1.0-VECC-1

Reference(s): E2/T1/S7/pg. 7

a) Please provide the customer group rate riders as indicated in Table 35 at the above reference.

Response:

a) Alectra Utilities has provided the customer group rate riders in Table 1. The customer specific bill adjustments for Global Adjustment and Capacity Based Recovery are provided in Tabs 6.1a and 6.2a of Alectra Utilities 2018 Rate Generator Model for the Horizon Rate Zone. The rate riders presented in Table 1, are based on the updated Rate Generator and IRM Models filed as Alectra Utilities response to G-Staff-2.

Table 1 - Rate Riders by Customer Group – Horizon Utilities RZ

Customers - GENERAL SERVICE 50 TO 4,999 KW	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs	$0.1075				
Class A (Jan-Dec, 2016)	$0.1075	$(0.4519)			
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)	$0.1075	$(0.4519)			specific to customer
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)	$0.1075	$(0.4519)			specific to customer
Class B non-RPP (Jan-Dec, 2016) Customers	$0.1075	$(0.4519)	$(0.01719)	$(0.0018)	
Class B RPP Customers	$0.1075	$(0.4519)	$(0.01719)		

Customers - LARGE USE (1)	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs	$0.1412				
Class A (Jan-Dec, 2016)	$0.1412	$(0.6689)			
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)	$0.1412	$(0.6689)			specific to customer
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)	$0.1412	$(0.6689)			specific to customer
Class B non-RPP (Jan-Dec, 2016) Customers	$0.1412	$(0.6689)	$(0.02595)	$(0.0018)	
Class B RPP Customers	$0.1412	$(0.6689)	$(0.02595)		

Customers - LARGE USE WITH DEDICATED ASSETS	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs	$0.1628				
Class A (Jan-Dec, 2016)	$0.1628	$(0.5507)			
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)	$0.1628	$(0.5507)			specific to customer
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)	$0.1628	$(0.5507)			specific to customer
Class B non-RPP (Jan-Dec, 2016) Customers	$0.1628	$(0.5507)	0.0000	0.0000	
Class B RPP Customers	$0.1628	$(0.5507)	0.0000		

Customers - RESIDENTIAL; GENERAL SERVICE LESS 50 KW; UNMETERED SCATTERED LOAD	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs					
Class A (Jan-Dec, 2016)					
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)					
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)					
Class B non-RPP (Jan-Dec, 2016) Customers	$(0.0009)	$0.0000	$(0.00005)	$(0.0018)	
Class B RPP Customers	$(0.0009)	$0.0000	$(0.00005)		

Customers - SENTINEL LIGHTING	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs					
Class A (Jan-Dec, 2016)					
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)					
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)					
Class B non-RPP (Jan-Dec, 2016) Customers	$(0.3376)	$0.0000	$(0.01727)	$(0.0018)	
Class B RPP Customers	$(0.3376)	$0.0000	$(0.01727)		

Customers - STREET LIGHTING	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs					
Class A (Jan-Dec, 2016)					
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)					
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)					
Class B non-RPP (Jan-Dec, 2016) Customers	$(0.3354)	$0.0000	$(0.01715)	$(0.0018)	
Class B RPP Customers	$(0.3354)	$0.0000	$(0.01715)		

1.0-VECC-2

Reference(s): E2/T1/S2/pg. 13

Pre-amble: In the Board approved settlement agreement EB-2014-0002 it states:

“Horizon Utilities agrees to undertake a Service Charge Cost Recovery Study that focuses on determining the appropriate level of service charges and impacts (e.g. a determination of who may be subsidizing whom). The purpose of the study is to consider the extent which the service charges are reflective of the costs of providing the services. Horizon Utilities agrees to collaborate with intervenor representatives on the terms of reference for this study. Horizon Utilities has agreed to file this study as part of its 2020 rebasing application. Horizon Utilities agrees to explore opportunities to collaborate with other utilities on the study including the sharing of costs.”

a) Alectra states that no such study has yet begun. Please provide an update on Alectra’s intentions with respect to the agreed upon study.

Response:

a) Included in Alectra Utilities’ predecessor, Horizon Utilities’ Settlement Agreement in its Custom IR Application (EB-2014-0002) was an agreement to retain an external consultant to conduct a study of its Specific Service Charges for the purposes of determining appropriate levels of charges. Alectra Utilities was to consult with intervenor representatives in the Custom IR proceeding in establishing the Terms of Reference for the study. Included in the Settlement Agreement was the provision to explore opportunities to collaborate with other utilities on the study including the sharing of costs.

Alectra Utilities is aware that the Ontario Energy Board (“OEB”) commenced a *Review of Miscellaneous Rates and Charges* (EB-2015-0304). Alectra Utilities is evaluating whether the second phase of the OEB’s review will include a Specific Service Charges review, as referenced in the Settlement Agreement. In the event that it does, Alectra Utilities expects that this would be in line with the intent in the Settlement Agreement for the sharing of costs.

1.0-VECC-3

Reference(s): E2/T1/S9, page 5 & LRAMVA Work Form, Tab 2

Please provide references for the LRAMVA Thresholds set for the years 2012- 2015 by customer class.

a) What was the last year of actual data used in developing the load forecast for EB-2010-0131 when the threshold for 2011-2014 was established?

b) What was the last year of actual data used in developing the load forecast for EB-2014-0002 when the threshold for 2015 was established?

c) Are the threshold values based on annualized savings consistent with the manner in which the IESO reports verified results?

Response:

a) The last year of actual data used in developing the load forecast for EB-2010-0131 when the threshold for 2011-2014 was established was 2009, as provided in EB-2010-0131, Exhibit 3, Tab 2, Schedule 1, referenced below:

Horizon Utilities Corporation
EB-2010-0131
Exhibit 3
Tab 2
Schedule 1
Page 3 of 5
Filed: August 26, 2010

Tables 3-5, 3-6, and 3-7 below provide a summary of the weather normalized load and customer/connection forecast used in this Application.

Table 3-5 - Summary of Load and Customer/Connection Forecast

Year	Billed (GWh)	Growth (GWh)	Percent Change	Customer/ Connection Count	Growth	Percent Change (%)
Billed Energy (GWh) and Customer Count / Connections						
2008 Board Approved	5,600.3			289,425		
2003 Actual	5,531.4			280,203		
2004 Actual	5,512.5	(18.9)	(0.3%)	281,634	1431.0	0.5%
2005 Actual	5,654.0	141.5	2.6%	283,505	1870.9	0.7%
2006 Actual	5,349.7	(304.3)	(5.4%)	284,980	1475.0	0.5%
2007 Actual	5,260.1	(89.5)	(1.7%)	286,154	1174.6	0.4%
2008 Actual	5,121.1	(139.1)	(2.6%)	287,292	1138.0	0.4%
2009 Actual	4,597.3	(523.8)	(10.2%)	288,245	952.5	0.3%
2010 Normalized Bridge	**4,788.5**	**191.2**	**4.2%**	**289,617**	**1371.6**	**0.5%**
2011 Normalized Test	**4,660.0**	**(128.5)**	**(2.7%)**	**290,997**	**1380.7**	**0.5%**

2003 to 2009 are weather actual while 2010 and 2011 are weather normalized. Horizon Utilities currently does not have a process to adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and is used in this application.

Total Customers and Connections are on a midyear basis and streetlight, sentinel lights, and unmetered loads are measured as connections.

b) The last year of actual data used in developing the load forecast for EB-2014-0002 when the threshold for 2015 was established was 2013, as detailed below in the overview of the forecasting approach found in EB-2014-0002, Exhibit 3, Tab 1, Schedule 2.

It is important to note that the load forecast was developed by a regression analysis model which incorporated historical years of actual data to predict future load and as a result the impact related to a single year of data would immaterially influence the forecast year.

Horizon Utilities Corporation
EB-2014-0002
Exhibit 3
Tab 1
Schedule 2
Page 5 of 33
Filed: April 16, 2014

Overview of Forecasting Approach

Horizon Utilities developed regression models using a customer class specific approach in order to forecast future loads for each customer class. Horizon Utilities developed weather normalized load forecasts for rate classes other than the Large Use customer class as follows:

- A customer class weather normalized billed energy forecast was developed for each rate class based on a multifactor regression model that incorporates: historical load, weather, calendar related events, prices, and economic factors;
- Rate class forecasts were then adjusted for Conservation and Demand Management ("CDM") savings projections by subtracting the cumulative monthly savings impact from the class specific sales forecasts.

Horizon Utilities based the load forecast models on actual kWh sales through December 2013.

c) The threshold values are based on annualized savings consistent with the manner in which the IESO reports verified results.

1.0-VECC-4

Reference(s): E2/T1/S9, page 4
LRAMVA Work Form, Tab 1- LRAMVA Summary

a) According to the LRAMVA Summary Tab, Alectra is claiming savings for impact of Horizon's 2011 CDM programs persisting in 2012 (see cell D56). However, in Schedule 9 (page 4) Alectra indicates that it is only seeking lost revenues from the persistence of 2011 programs in 2013 and 2014. Please reconcile.

Response:

a) Alectra Utilities withdraws the recovery of 2011 persistence amounts in the 2012 lost revenue. The Horizon Utilities LRAMVA model tab 4. 2011-2014 LRAM has been updated accordingly. This is reconciled with Schedule 9 (Page 4), 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.

1.0-VECC-5

Reference(s): E2/T1/S9, page 3
Attachments 12 and 13

a) Please provide the excel versions of Attachments 12 and 13 as these are much easier to read/review.

Response:

a) The Excel versions of ATTACHMENT 12 and ATTACHMENT 13 – 2014 & 2015 FINAL IESO RESULTS REPORT HORIZON UTILITIES RZ can be found in the response to Board Staff: HRZ-Staff-14.

1.0-VECC-6

Reference(s): E2/T1/S9, page 4
LRAMVA Work Form, Tab 7- Persistence Data

a) If not already provided, please provide an excel version of the IESO report regarding the persistence of 2011-2014 CDM program savings through to and including 2015.

Response:

a) The information is provided in a response to the OEB Staff Interrogatories, reference: HRZ-Staff-14.

2.0-VECC-7

Reference(s): Exhibit 2/T2/S10/pg.12 Brampton ICM

a) Is Alectra aware of any Board precedent which allowed a CCRA obligation to be included as an ICM project? If so please provide a reference to that precedent(s) and an extract of the relevant decision.

b) What if any forecast risk does Alectra take with respect to similar projects (i.e. with potential CCRA payments to Hydro One)?

Response:

a) Alectra Utilities is aware of the recent decision of the Ontario Energy Board ("OEB") in the Enersource Hydro Mississauga Price Cap IR and Incremental Capital Module ("ICM") application (EB-2015-0065), in which the OEB approved the recovery of the payment to Hydro One for the capital cost recovery agreement ("CCRA"). The relevant section can be found on p.9-10 of the OEB's decision, dated April 7, 2016.

b) Alectra Utilities enters into a CCRA agreement with Hydro One, where Hydro One investments are required to address shortfalls in transmission system capacity identified in Alectra Utilities long term load forecast. Alectra Utilities' initial contribution is calculated based upon a 25 year forecast of future load at the time that it enters into a CCRA with Hydro One for the construction/expansion of a Transformer Station ("TS"). The forecast risk taken by Alectra Utilities with respect to Hydro One payments comes from the forecast load and related revenue true-ups that occur at the 5^{th}, 10^{th} and in some cases, the 15^{th} anniversary of the agreement.

The 25 year load forecasts are trued-up to actual load at these intervals and Alectra Utilities, would be required to make payments to Hydro One if load forecasts and related revenues are not realized. In the unlikely scenario that load is higher than expected, Hydro One would pay the distributor at the true-up date.

The distributor holds the forecast risk; Hydro One does not bear any risk if the load drops. Hydro One receives payment in either scenario, i.e., through the load guarantee if the load drops or through higher revenue if load increases.

2.0-VECC-8

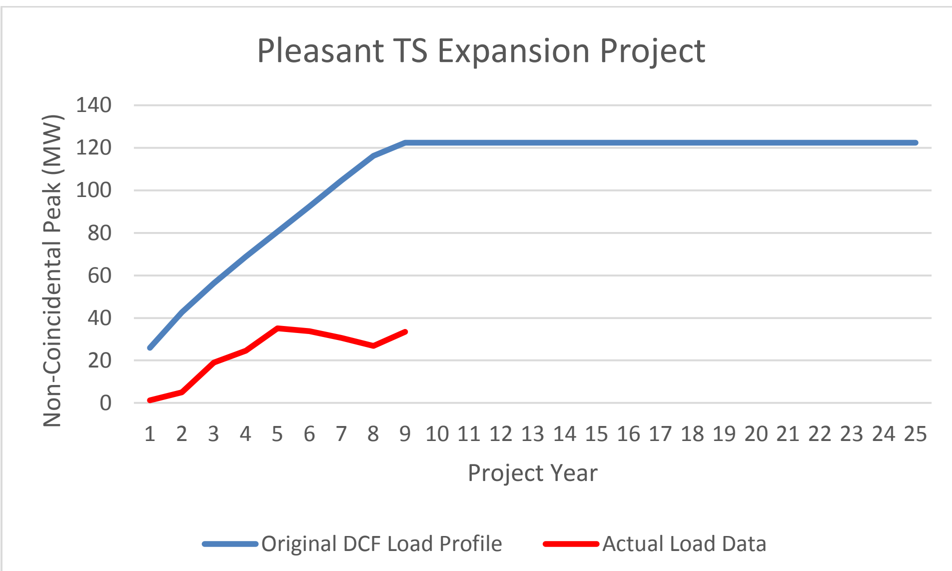
Reference(s): Attachment 21/pg.3 Brampton ICM

Please amend Figure 1 to include the forecast peak demand for the Pleasant TS at the time of the signing of the first Hydro One agreement.

Response:

Alectra Utilities has amended Figure 1 to include the forecast peak demand for the Pleasant TS at the time of signing the Hydro One agreement.

Figure 1 – Pleasant TS Peak Demand Forecast



2.0-VECC-9

Reference(s): Exhibit 2/Tab 2/Schedule 10

The following extracts are provided from EB-2014-0083 and (2nd table) the current application.

CATEGORY	20 Test Year	20 16	20 17	20 18	20 19
System Access	17,605,940	14,998,570	14,444,690	14,878,370	15,080,960
System	8,803,080	9,310,580	10,329,890	10,120,900	9,006,760
System Service	1,472,290	599,560	530,230	623,630	676,870
General Plant	9,741,020	9,288,690	3,966,470	3,981,820	3,740,710
TOTAL	**37,622,330**	**34,197,400**	**29,271,280**	**29,604,720**	**28,505,300**

Source: Appendix 2-AB Exhibit 2, Tab 5, Schedule 1 EB-2014-0083

Category	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020
System Access	$21,333	$20,792	$15,378	$20,751	$13,560	$20,333
System Renewal	$15,674	$8,144	$11,980	$12,855	$9,677	$10,960
System Service	$1,779	$826	$1,812	$529	$575	$682
General Plant	$3,785	$996	$11,048	$3,934	$16,332	$11,098
Total	**$42,571**	**$30,757**	**$40,218**	**$38,069**	**$40,144**	**$43,073**

Source Table 60, Exhibit 2, Tab 2, Schedule 10 EB-2017-0024

a) **Please provide an explanation as to the variance between the capital expenditures in the four reporting areas (System Access, System Renewal, System Service, and General Plant) shown in Table 60 and the forecast capital expenditures amounts shown in Appendix 2-AB provided as evidence to the Board in EB-2014-0083.**

b) **Specifically, please explain why the projected expenditures provided to the Board in late 2014 for 2017 capital expenditures of $29.271M were significantly less than the current project in 2017 of $40.218M.**

c) **In EB-2014-0083 Brampton Hydro filed a detailed capital expenditure plan, distribution system plan and an Asset Condition Assessment report by an expert independent consulting firm (Kinectrics Inc.). Brampton provided over 1000 pages of evidence supporting capital expenditures between 2017 and 2018 of approximately $87.4M. In this application the Brampton RZ now expects to require $118.3M in capital expenditures over the same period. Please explain the significant change in the Brampton RZ needs since 2015 which argue for this 35% increase in capital expenditures over the stated period.**

d) **Please recalculate the revenue requirement impact of the ICM based on the original project capital expenditures in the Brampton RZ of 2017 of $29.271 million.**

Response:

a) and b) Please see Tables 1-3 below for the variance between Appendix 2-AB provided as evidence to the Board in EB-2014-0083 and the current forecast as per Table 60:

Table 1 – Capital expenditures in EB-2014-0083

Appendix 2-AB					
Category	**2015**	**2016**	**2017**	**2018**	**2019**
System Access	$17,605,940	$14,998,570	$14,444,690	$14,878,370	$15,080,960
System Renewal	$8,803,080	$9,310,580	$10,329,890	$10,120,900	$9,006,760
System Service	$1,472,290	$599,560	$530,230	$623,630	$676,870
General Plant	$9,741,020	$9,288,690	$3,966,470	$3,981,820	$3,740,710
TOTAL EXPENDITURE	$37,622,330	$34,197,400	$29,271,280	$29,604,720	$28,505,300

Table 2 – Capital expenditures EB-2017-0024

Current Forecast					
Category	**Actual 2015**	**Actual 2016**	**BP 2017**	**BP 2018**	**BP 2019**
System Access	$21,333,048	$20,792,168	$15,378,476	$20,751,276	$13,560,040
System Renewal	$15,674,384	$8,143,641	$11,979,923	$12,855,011	$9,677,490
System Service	$1,779,131	$825,738	$1,812,259	$529,158	$574,580
General Plant	$3,784,937	$995,861	$11,047,804	$3,934,035	$16,331,610
TOTAL EXPENDITURE	$42,571,500	$30,757,408	$40,218,462	$38,069,480	$40,143,720

Table 3 – Capital expenditure variance

Variance					
Category	**2015**	**2016**	**2017**	**2018**	**2019**
System Access	$3,727,108	$5,793,598	$933,786	$5,872,906	($1,520,920)
System Renewal	$6,871,304	($1,166,939)	$1,650,033	$2,734,111	$670,730
System Service	$306,841	$226,178	$1,282,029	($94,472)	($102,290)
General Plant	($5,956,083)	($8,292,829)	$7,081,334	($47,785)	$12,590,900
TOTAL EXPENDITURE	$4,949,170	($3,439,992)	$10,947,182	$8,464,760	$11,638,420

Variance Explanations

Year	Variance Breakdown & Comments		
	Category	Variance	
2015	SA	$3,727,108	Actual costs higher by $3.7M due to Pleasant & Goreway load guarantees $5.4M, partially offset by lower spend on road widening $1M, and new Commercial/Industrial customers $0.7M.
	SR	$6,871,304	Higher System Renewal expense of $6.9M due to 16S meter replacement costs of $5.6M, and higher 4.16Kv to 27.6Kv conversion costs $1.3M.
	SS	$306,841	Not Material
	GP	($5,956,083)	General Plant costs were lower due to the inclusion of ERP costs of $5M in the DSP model, as well as lower actual building upgrade costs $1M.
	Total	$4,949,170	

Year	Variance Breakdown & Comments		
	Category	Variance	
2016	SA	$5,793,598	Actual costs higher by $5.8M mainly due to higher new residential low density connections $2.5M, industrial/commercial connections $2.1M, and road widening $0.7M.
	SR	($1,166,939)	Lower System Renewal expense of $1.2M mainly due to lower spend on feeder cable replacement $2.1M and distribution cable replacement $1.3M, partially offset by higher expenditure on MS14 Power transformers $1.2M and the 44kv/13.8kv MS22 transformer replacement $1M.
	SS	$226,178	Not Material
	GP	($8,292,829)	General Plant costs were lower due to the inclusion of ERP costs of $5.1M in the DSP model, as well as lower actual fleet costs $1.8M, and building upgrade costs $1.2M.
	Total	($3,439,992)	

Year	Variance Breakdown & Comments		
	Category	Variance	
2017	SA	$933,786	Current Forecast is higher than DSP by $0.9M mainly due to the inclusion of the Electric Bus charging station in the budget of $0.8M.
	SR	$1,650,033	Current Forecast higher than DSP primarily due to higher projected costs for Socket Gate upgrades $0.9M, ND-10 Radio change-outs $0.7M.
	SS	$1,282,029	Current Forecast higher than DSP due to the inclusion of MS20 Station Protection upgrade of $1.375M. DSP model did not project expense for such upgrade.
	GP	$7,081,334	Current Forecast includes $6.8 M for ERP (Appendix 2-AB included $10M for ERP - $5M each in 2015&16).
	Total	$10,947,182	

Year	Variance Breakdown & Comments		
	Category	Variance	
2018	SA	$5,872,906	Current Forecast includes load guarantee true-up for Pleasant TS of $6.9M.
	SR	$2,734,111	Current Forecast higher than DSP mainly due to higher planned costs for the 4.16Kv to 27.6Kv conversion program $1.2M, Feeder Cable replacemet program $0.8M, Distribution Cable replacement program $0.5M, and C&I Metering Equipment Commissioning $0.5M.
	SS	($94,472)	Not Material
	GP	($47,785)	Not Material
	Total	$8,464,760	

Year	Variance Breakdown & Comments		
	Category	Variance	
2019	SA	($1,520,920)	Current Forecast is lower primarily due to lower road widening expense $1.4M.
	SR	$670,730	Current Forecast higher than DSP mainly due to higher 4.16Kv to 27.6Kv conversion program $0.8M.
	SS	($102,290)	Not Material
	GP	$12,590,900	Current Forecast higher than DSP due to inclusion of CIS expense of $14M.
	Total	$11,638,420	

c) In EB-2014-0083, Alectra Utilities predecessor Brampton, projected capital spend over the three years 2017, 2018 and 2019 totaled $87.4M; however, the current projections over the same three years are now $118.4M. The $31M variance is mainly attributed to the inclusion of CIS spend in 2019 of $14M; ERP spend of $6.8M in 2017 (which was included in 2015-16 in EB-2014-0083 but not incurred); and the CCRA payment of $6.9M for the Pleasant TS that was not included in the prior filing.

d) The Brampton RZ 2018 ICM calculations are based on the last approved cost of service rates in 2015 and its approved 2015 capital expenditures of $37.6 million. There is no impact on the 2018 ICM revenue requirement by changing the projected 2017 capital expenditures of $40.2 million to $29.271 million.

2.0-VECC-10

Reference(s): Exhibit 2/Tab 2/Schedule 10/Table 60 Brampton ICM

a) Please clarify whether the system access category of capita spending shown in Table 60 is net of capital contributions.
b) Please provide the actual and forecast contributions for system access projects for the 2013-2019 period.

Response:

a) Yes, the capital spending data shown in Table 60 is net of Capital Contributions.

b) Table 1 provides actual and forecasted Capital Contributions for the years 2013-2019.

Table 1 – Actual and Forecasted Capital Contribution 2013-2019

	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019
Capital Contributions	$19,495	$14,557	$11,772	$13,186	$12,891	$13,360	$12,089

2.0-VECC-11

Reference(s): Exhibit 2/Tab 2/Schedule 10

a) Please provide the actual 2017 capital expenditures to date.

Response:

a) Table 1 provides actual August year-to-date capital expenditures for the Brampton RZ.

Table 1 - Capital expenditures – YTD August 2017

Category	YTD August 2017 ($000s)
System Access	$5,648
System Renewal	$5,656
System Service	$563
General Plant	$1,221
Total Brampton Rate Zone	**$13,088**

3.0-VECC-12

Reference(s): E2/T3/S5/pg.9

a) Please provide the customer group rate riders as indicated in Table 80 at the above reference.

Response:

a) Alectra Utilities has provided the customer group rate riders in Table 1. The customer specific bill adjustments for Global Adjustment and Capacity Based Recovery are provided in Tabs 6.1a and 6.2a of Alectra Utilities 2018 Rate Generator Model for the PowerStream Rate Zone. The rate riders presented in Table 1, are based on the updated Rate Generator and IRM Models filed as Alectra Utilities' response to G-Staff-2.

Table 1 - Rate Riders by Customer Group – PowerStream RZ

Customers - RESIDENTIAL	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs					
Class A (Jan-Dec, 2016)					
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)					
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)					
Class B non-RPP (Jan-Dec, 2016) Customers	$(0.0028)		$0.0002	$(0.0017)	
Class B RPP Customers	$(0.0028)		$0.0002		

Customers - GENERAL SERVICE LESS 50 KW; UNMETERED SCATTERED LOAD	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs					
Class A (Jan-Dec, 2016)					
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)					
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)					
Class B non-RPP (Jan-Dec, 2016) Customers	$(0.0027)		$0.0002	$(0.0017)	
Class B RPP Customers	$(0.0027)		$0.0002		

Customers - SENTINEL LIGHTING	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs					
Class A (Jan-Dec, 2016)					
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)					
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)					
Class B non-RPP (Jan-Dec, 2016) Customers	$(0.9968)		$0.0890	$(0.0017)	
Class B RPP Customers	$(0.9968)		$0.0890		

Customers - STREET LIGHTING	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs					
Class A (Jan-Dec, 2016)					
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)					
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)					
Class B non-RPP (Jan-Dec, 2016) Customers	$(0.9768)		$0.0864	$(0.0017)	
Class B RPP Customers	$(0.9768)		$0.0864		

Customers - GENERAL SERVICE 50 TO 4,999 KW	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs	$0.0182				
Class A (Jan-Dec, 2016)	$0.0182	$(1.0567)			
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)	$0.0182	$(1.0567)			specific to customer
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)	$0.0182	$(1.0567)			specific to customer
Class B non-RPP (Jan-Dec, 2016) Customers	$0.0182	$(1.0567)	$0.0900	$(0.0017)	
Class B RPP Customers	$0.0182	$(1.0567)	$0.0900		

Customers - LARGE USE	DVA Rate Rider 1	DVA Rate Rider 2	CBR B Rate Rider	GA Rate Rider	GA/CBR Bill Adjustment
WMPs	$(1.2283)				
Class A (Jan-Dec, 2016)	$(1.2283)				
Class B non-RPP (Jan-Jun, 2016)/Class A (Jul-Dec, 2016)	$(1.2283)				specific to customer
Class A non-RPP (Jan-Jun, 2016)/Class B (Jul-Dec, 2016)	$(1.2283)				specific to customer
Class B non-RPP (Jan-Dec, 2016) Customers	$(1.2283)				
Class B RPP Customers	$(1.2283)				

3.0-VECC-13

Reference(s): E2/T3/S7 (Deferral & Variance Accounts)

a) Are the Metrolinx Crossing Remediation Project expenditures subject to contributions from Metrolinx?
b) If yes, please explain how the contributions will accounted for in the proposed new deferral account.

Response:

a) The Metrolinx Crossing Remediation Project is not subject to contributions from Metrolinx. Individual crossings are subject to a crossing agreement between Alectra Utilities and Metrolinx. Current crossing agreements state; "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".

b) Please see Alectra Utilities' response to a).

3.0-VECC-14

Reference(s): E2/T3/S10

Pre-amble: The following table is reproduced from EB-2015-0003 (Exhibit G, Tab 2, page 3)

	2015	2016	2017	2018	2019	2020	
	Proposed	Proposed	Proposed	Proposed	Proposed	Proposed	Total
General Plant	$24,544,709	$17,631,419	$19,557,978	$13,966,910	$16,840,554	$18,205,522	$110,747,091
System Access	$24,145,118	$28,232,154	$28,469,723	$29,560,667	$28,726,052	$31,866,709	$171,000,423
System Renewal	$42,388,194	$48,714,625	$51,500,169	$52,051,933	$52,970,854	$52,405,780	$300,031,555
System Service	$27,321,977	$38,321,819	$32,071,882	$29,920,325	$26,963,080	$23,022,061	$177,621,144
Grand Total	$118,399,998	$132,900,017	$131,599,752	$125,499,835	$125,500,540	$125,500,071	$759,400,213

a) Please explain the significant ($31 million shortfall) in actual 2016 capital expenditures as compared to that provided to the Board in EB-2015-0003. Specifically identify which projects were delayed or removed in order to make these savings.

Response:

a) PowerStream filed a Custom Incentive Rate (‘CIR”) application with the Ontario Energy Board (“OEB”) on May 22, 2015, seeking approval for changes to the rates that PowerStream charges for electricity distribution, to be effective January 1, 2016 and each year until December 31, 2020. The OEB did not approve PowerStream’s application to set rates for 2016-2020. 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). 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”. Due to the timing of the OEB’s Decision in the 2016 Custom IR Application, PowerStream delayed spending in 2016, pending the outcome of the decision. Projects in all categories were paced and deferred to future years. The table below provides a listing of key plan categories impacted:

Table 1 - Project Categories 2016

2016 per EB-2015-0003 (Exhibit G, Tab 2, page 3) (in MM)		$132.9
General Plant		**($8.3)**
IT and Info/Communication Systems	($4.9)	
Smart Grid projects moved to deferral accounts	($1.3)	
Other projects paced	($2.0)	
System Access		**($5.4)**
System Access - changes in customer demand		
System Renewal		**($6.3)**
Storm Hardening projects	($3.6)	
UG Lines - Planned Asset Replacement	($3.7)	
Other System Renewal	$1.0	
System Service		**($11.7)**
Additional Capacity - Lines	($6.9)	
Additional Capacity - Stations	($3.0)	
Other System Service	($1.8)	
2016 Rate Base Actual Spend		**$101.1**

3.0-VECC-15

Reference(s): E2/T3/S10

Pre-amble: Alectra notes that in EB-2015-0003 the Board that it was up to-"*PowerStream to determine the appropriate way to allocate the capital budget within the limits of the total capital budget for the year*". In that same Decision the Board also stated:

PowerStream has proposed a total capital budget of $131.6 million for 2017. The OEB considers that the capital budget should be decreased, and approves a total capital budget of $115.8 million in 2017 representing a 12% cut from the proposed level. In arriving at this amount, the OEB took into account a number of elements of the proposed capital budget that it considers should reasonably be reduced. Where a specific expenditure is not discussed, this means that the OEB did not have concerns with it. *The elements of the capital budget that the OEB considers should reasonably be reduced are discussed below*. (emphasis added)

The Board included this summary table of those items:

2017 Capital Budget proposed by PowerStream:	**131,600**
OEB Reductions	
System Renewal	
Underground Cable Replacement/Injection Program	-5,120
Pole Replacement Program	-1,380
Rear Lot Supply Remediation Program	-2,200
Mini-Rupter Switch Replacement Program	-405
Unscheduled Replacements of Distribution Equipment	-190
General Plant	
Customer Information System (CIS) Modifications	-6,700
General	
Internal/External Resource Mix For Capital Projects	-240
Total Reductions	-16,235
2017 Revised Capital Budget	**115,365**

(Source EB-2015-0003 Decision and Order page 15.)

a) **Please compare and contrast the Board's list of exclusions and the**

proposed ICM projects shown in Table 103. For any projects that overlap (i.e. Rear Lot Remediation) please explain how Alectra has addressed the Board's specific concerns as articulated at pages 14-21 of the Decision EB-2015-0003.

b) Specifically address how the Alectra addressed in this application the following concern of the Board:

"*However PowerStream has not provided evidence that it took advantage of the opportunities it did have to obtain customer views on the specifics of its proposals before those proposals were decided on. Some examples of this are discussed below under the proposed capital budgets for rear lot relocation and PowerStream's new Customer Information System.*"

Response:

a) Table 1 identifies the Board's list of exclusions and the proposed ICM projects shown in Table 103 in Exhibit 2, Tab 3, Schedule 10 of the application, for projects that overlap.

Table 1 – OEB exclusion list compared to the list of ICM Projects

PowerStream Plan Category	Project	2017 DSP (Submitted)	2017 Budget	2018 ICM Projects	Variance 2017 Budget vs DSP	Variance 2018 ICM vs DSP
Storm Hardening & Rear Lot Conversion	Storm Hardening & Rear Lot Conversion	$7,999,752	$5,779,749	$4,341,820	$2,220,003	$3,657,932
UG Lines - Planned Asset Replacement	Underground Cable Replacement/Injection Minirupter Switch Replacement	$18,469,828	$12,889,613	$13,065,399	$5,580,215	$5,404,429

Rear lot and Storm hardening spend was reduced by $2.2MM in the 2017 budget and $3.76MM in 2018 compared to the 2017 DSP budget. The budgeted spend in 2018 was reduced by additional $1.46MM for the Rear Lot project in addition to the Ontario Energy Board's recommended $2.2 MM reduction, following the customer engagement activities for Alectra Utilities 2018 Rate Application.

Alectra Utilities reduced the cable replacement/injection spend in 2017 and 2018 by $5.6MM and $5.4MM respectively.

b) In 2017, Alectra Utilities engaged Innovative Research Group to solicit feedback from customers on proposed incremental funding for the PowerStream rate zone. Details of the customer engagement initiative as well as results are provided in E2/T3/S10 in pages 11 to 15. Based on feedback from customers, Alectra Utilities revised its ICM request by reducing

$1.46MM, which represents the removal of the Rear Lot Supply Remediation project at Queen/Greenway. Please see Alectra Utilities response to PRZ-Staff-10 for an explanation of the changes to the rear lot renewal projects. Additionally, please refer to Alectra Utilities' response to PRZ-AMPCO-4 for an explanation of the scope and investment need in the Customer Information System. Alectra Utilities is not proposing incremental capital funding for the Customer Information System.

3.0-VECC-16

Reference(s):

Pre-amble. In EB-2015-0003 the Board made the following statement in consideration of the PowerStream Capital Plans:

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

a) Please explain what benchmarking and measures of continuous improvement have been made to address the Board's concern.

b) In the absence of significant initiatives to address the Board's concern why does Alectra believe the Board should allow for an overall capital budget above the dollar value last Board approved by the Board.

Response:

a) In order to address the OEB's concerns identified in the statements in the PowerStream Decision and Order (EB-2015-0003), PowerStream undertook a review of the capital investment plan, with a focus on customer value and improvement on execution of capital projects. PowerStream restructured initiatives such as the cable replacement and rear lot remediation programs to be implemented as distinct individual projects rather than programs. The objective of the restructuring was to evaluate, prioritize and pace distinct projects based on individual project cost/ benefit analysis and justification.

Further, by restructuring these programs into individual projects the result is a more clearly defined project scope, schedule and cost estimate that directly addresses an investment driver and provides an alignment of the investment to the expected customer value.

Alectra Utilities has continued this revised approach in the PRZ for the cable replacement and rear lot remediation projects. Alectra Utilities uses project management controls for each specific project, rather than implementing the initiatives as a program with pooled resources. Alectra Utilities has taken a disciplined approach and expects to deliver the desired outcomes that benefit customers on schedule, within scope and budget as compared to the previous program structure.

b) With the restructuring of the cable replacement and rear lot remediation programs into projects, Alectra Utilities has continued to improve and enhance customer value, beyond the measures and metrics presented in Section 5.2.3 Performance Measurement for Continuous Improvement of the PowerStream 2015-2020 DSP (EB-2015-0003/SII/Exhibit G/Tab 2/Section 5.2.3). In 2017, Alectra Utilities forecasts to deliver the Cable Replacement at a rate of $297 per meter, a 28% reduction, relative to the $415 per meter rate planned in the PowerStream DSP. Alectra Utilities is forecast to deliver the Left Behind Cable Replacement initiative at rate of $456 per meter, an 11% reduction relative, to the $515 per meter rate planned in the PowerStream DSP. Alectra Utilities, and its predecessor PowerStream, have taken significant steps to address the concerns articulated by the OEB in the Decision and Order (EB-2015-003).

In addition to the cable replacement program restructuring, PowerStream restructured the rear lot remediation program with the objective to drive more value for the customer while managing the reliability and operational concerns with rear lot service construction. Based on the review, PowerStream restructured the projects to pace the investments over a longer term. PowerStream also determined that additional design options, namely utilizing overhead infrastructure where possible, as opposed to a strictly underground solution, will further reduce the cost of certain projects.

Of the 35 locations in the PRZ service territory that require rear lot remediation, PowerStream determined that four locations could be remediated using a rear lot overhead design; two locations could be remediated with a front lot overhead design; and two locations can now be remediated with a hybrid overhead/underground design. The remaining 27 locations will continue to require remediation to front underground, as originally planned. Through the introduction of alternative design options, Alectra Utilities continues to seek and identify cost saving opportunities, while managing reliability and operational concerns with rear lot service construction in the PowerStream RZ.

3.0-VECC-17

Reference(s): E2/T3/S10/pg. 21 – York Region Rapid Transit VIVA Bus Rapid Transit and H2 projects

a) Please explain the capital contribution policy that applies to the YRRT/BRT projects.
b) Is the $11.24 million noted for this project net of contributions?
c) Given the level of uncertainty described in the evidence and similarities with the proposed Metrolinx Crossing Remediation and Go Rail Network deferral (variance) accounts-has Alectra considered a specific variance accounting for this project? If not, please explain why and what difference the project(s) is expected in comparison to the other two identified by Alectra for Deferral/Variance account treatment.

Response:

a) The capital contribution policy that applies to the YRRT/BRT projects follows the cost share arrangement as per the Public Service Works on Highway Act. For convenience a link has been provided to the Act (https://www.ontario.ca/laws/statute/90p49). Specifically the Act states that the cost of labour shall be apportioned equally between the road authority and operating corporation – refer to P.49, s. 2 (2) of the Act.

b) Yes, the $11.24MM noted for the YRRT project is net of contributions.

c) Alectra Utilities has not considered specific variance accounting for this project. Alectra Utilities believes the level of certainty for this project to be constructed in 2018 is very likely. The YRRT project is funded by Metrolinx. With funds secured by the Region of York, Alectra Utilities does not have reason to believe the relocation work will not take place.

3.0-VECC-18

Reference(s): E2/T3/S10/pgs. 20-33

a) Were all of the projects described at the above reference identified in the Distribution System Plan filed with the Board in EB-2015-0003?

b) If not, please identify the incremental projects and explain why these projects were not identified the last DSP five year plan.

c) For all projects that were identified and for which project estimates were provided in the DSP please compare and contrast the prior $ estimates with the current projections.

Response:

a) b) c) Please see Alectra Utilities' response to PRZ-Staff-7.

3.0-VECC-19

Reference(s): E2/T3/S9, page 5
LRAMVA Work Form, Tab 2

a) Please provide references for the LRAMVA Thresholds set for the years 2014-2015 by customer class.
b) What was the last year of actual data used in developing the load forecast for EB-2012-0161 when the threshold for 2013-2015 was established?
c) Are the threshold values based on annualized savings consistent with the manner in which the IESO reports verified results?

Response:

a) The LRAMVA threshold approved in the 2013 cost of service (COS) application was used as the comparator against actual savings in the period of the LRAMVA claim. Table 1 below provides references for the LRAMVA Thresholds set for the years 2014-2015.

Table 1: LRAMVA Thresholds by Customer Class

Rate Class	kWh	kW	Inputs for LRAMVa Threshold
Res	44,207,932	-	44,207,932
GS<50	16,984,563	-	16,984,563
GS>50	73,463,176	195,431	195,431
LU	1,251,684	3,732	3,732
USL	208,627	-	208,627
Sentinel	7,674	20	20
Street Light	976,097	2,868	2,868
	137,099,754	**202,051**	

b) 2011 was the last year of actual data used in developing the load forecast for EB-2012-0161 when the threshold for 2013-2015 was established. The energy purchases forecasting model utilized monthly loads time series from January 2002 to December 2011.

c) The threshold values based on annualized savings are consistent with the manner in which the IESO reports verified results since the IESO actual verified results are annualized.

3.0-VECC-20

Reference(s): E2/T3/S9, page 4
Attachments 29 and 30

a) Please provide the excel versions of Attachments 29 and 30 as these are much easier to read/review.

Response:

a) Alectra Utilities provides the Excel versions of Attachment 29 (2011-2014 IESO Final Results Report_PowerStream RZ) and Attachment 30 (2015 IESO Final Results Report_PowerStream RZ) in its response to Staff-PRZ-Staff-20.

3.0-VECC-21

Reference(s): E2/T3/S9, page 4
LRAMVA Work Form, Tab 7- Persistence Data

a) If not already provided, please provide an excel version of the IESO report regarding the persistence of 2011-2014 CDM program savings through to and including 2015.

Response:

a) The 2011-2014 IESO Report regarding the persistence of CDM program savings can be found in Alectra Utilities' response to PRZ-Staff-20.

3.0-VECC-22

Reference(s): E2/T3/S9, page 4
LRAMVA Work Form, Tab 1- LRAMVA Summary

a) Please explain why for PowerStream the Application includes for the 2015 claim, the persisting impacts from 2011-2014 programs whereas in Horizon's case it does not.

Response:

a) Alectra Utilities' predecessor, Horizon Utilities, filed a 2015 Custom Incentive Rate-setting Application (EB-2014-0002) with the Ontario Energy Board ("OEB") on April 16, 2014. Horizon Utilities 2015 load forecast incorporated 2011-2014 persistence from Conservation and Demand Management ("CDM") programs. Alectra Utilities' predecessor, PowerStream, filed a 2013 Cost of Service Application (EB-2012-0161) with the OEB on May 4, 2012. PowerStream's load forecast did not include persistence from 2011-2014 CDM programs. Alectra Utilities is proposing to dispose of 2014 and 2015 Lost Revenue Adjustment Mechanism ("LRAM") balances for the PowerStream rate zone.

3.0-VECC-33

Reference(s): E2/T3/S9, page 4
LRAMVA Work Form, Tab 1- LRAMVA Summary

a) Please explain why for Enersource the Application includes for the 2015 claim, the persisting impacts from 2011-2014 programs whereas in Horizon's case it does not.

Response:

a) Enersource has not filed an LRAMVA Application to dispose of balances for 2011- 2014 programs; therefore, in filing the 2015 claim, the persistence impacts from 2011-2014 programs are included. Please see Alectra Utilities' response to ERZ-Staff-17.

Horizon Utilities filed a Custom Incentive Rate Application for 2015-2019 (EB-2014-0002), where the impact of CDM activity up to and including 2014 was embedded in the load forecast in the application.

4.0-VECC-23

Reference(s): E2/T4/S11/pg.4

a) Please provide the 2015 and 2016 budget and actual capital expenditures in the form of Table 129.
b) Please provide the 2017 actual spending to date in the same form.

Response:

a) Table 1 provides 2015 and 2016 budget and actual capital expenditures in the same format as Table 129:

Table 1 – Actual and Budget Capital Expenditures

Category	Budget 2015	Actual 2015	Budget 2016	Actual 2016
System Access	$37,178	$52,732	$10,277	$11,823
System Renewal	$27,760	$37,472	$34,735	$35,196
System Service	$18,750	$16,297	$17,200	$12,723
General Plant	$10,335	$9,546	$12,796	$4,333
Total	**$94,023**	**$116,047**	**$75,008**	**$64,075**

b) Table 2 provides year to date August 2017 actual capital expenditures.

Table 2 – Actual Capital Expenditures year-to-date August 2017

Category	YTD August 2017 ($000s)
System Access	$4,733
System Renewal	$22,514
System Service	$6,793
General Plant	$1,977
Total	**$36,017**

4.0-VECC-24

Reference(s): E2/T4/S11/Table 129 & 2-Staff-3 EB-2015-0065 (attached)

a) In Enersource's last ICM application it presented forecast capital expenditures for the period 2016 through 2012. Please compare and contrast the projections for 2017 through 2021 shown in the prior table (attached) with those shown in Table 129.

b) Please provide an updated table similar to that filed at 2-Staff-3 which shows the CIAC amounts for the capital categories (including LRT/transit if applicable).

c) Please describe any significant change in capital planning that has occurred subsequent to the DSP and Asset Condition Assessment. That is, please highlight *material or significant* investments that are being made in light of the new plan and explain how these needs were identified only as part of the recent DSP/Asset Management exercise. For example, were the two new substations identified for the downtown core first identified as part of the DSP? Or were they contemplated in Enersource's last capital budget project presented to the Board? Similarly were the transformer remediation's described at pages 14-15 identified in EB-2015-0065 or only as part of the new DSP?

Response:

a) A comparison of the 2017 through 2021 capital expenditures from Alectra Utilities 2018-2022 DSP for the Enersource Rate Zone (Table 129) to the Enersource 2017-2021 DSP provided in EB-2015-0065 (Table 1) and variance explanation is provided in Table 2 below.

Table 129 - Alectra Utilities (Enersource Rate Zone) 2018-2022 DSP

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

Table 1 - Enersource 2017-2021 DSP (EB-2015-0065)

Category	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021
System Access	$ 12,785	$ 12,992	$ 13,031	$ 12,106	$ 8,236
System Renewal	$ 37,243	$ 38,240	$ 40,280	$ 38,570	$ 38,490
System Service	$ 13,015	$ 13,130	$ 12,825	$ 13,105	$ 13,490
General Plant	$ 11,337	$ 10,281	$ 10,794	$ 10,755	$ 9,984
Total Enersource RZ (Net)	**$ 74,379**	**$ 74,642**	**$ 76,930**	**$ 74,536**	**$ 70,201**

Table 2 – Capital Expenditure Forecast Variance: 2018-2022 DSP vs. 2017-2021 DSP

Category	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021
System Access	$ (4,671)	$ (1,313)	$ 766	$ 1,705	$ 4,515
System Renewal	$ 143	$ 2,670	$ 1,870	$ 2,950	$ 1,670
System Service	$ (1,868)	$ 292	$ 582	$ 612	$ 32
General Plant	$ (4,539)	$ (3,609)	$ (3,214)	$ (2,344)	$ (3,231)
Total Enersource RZ (Net)	**$ (10,934)**	**$ (1,959)**	**$ 4**	**$ 2,923**	**$ 2,986**

b) An updated table similar to that filed at 2-Staff-3 which shows the CIAC amounts for the capital categories (including LRT) is provided below.

Table 3 – Capital contributions by capital categories

Capital Spend 2017-2022

	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022
System Access	$12,820	$14,437	$13,474	$13,799	$13,429	$12,549
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	**$68,151**	**$75,441**	**$76,611**	**$77,447**	**$73,864**	**$69,365**
Administration Building	-	-	-	-	-	-
Hydro One TS Payments	-	-	-	-	-	-
LRT	$400	$4,400	$8,800	$8,550	$7,800	$5,200
Total						
TOTAL GROSS	$68,551	$79,841	$85,411	$85,997	$81,664	$74,565
CIAC - System Access	($5,106)	($5,658)	($5,478)	($5,538)	($5,478)	($5,238)
CIAC - System Renewal	-	-	-	-	-	-
CIAC - System Service	-	-	-	-	-	-
CIAC - General Plant	-	-	-	-	-	-
CIAC - LRT	-	($1,500)	($3,000)	($3,000)	($3,000)	($1,700)
CIAC	($5,106)	($7,158)	($8,478)	($8,538)	($8,478)	($6,938)
TOTAL NET	**$63,445**	**$72,683**	**$76,933**	**$77,459**	**$73,186**	**$67,627**

c) A variance is provided by investment category in Table 4 below along with explanation of material changes.

Table 4: Variance Comparison of 2018-2022 (2017) DSP vs. 2017-2021 (2015) DSP

Year	Variance Breakdown & Comments		
	Category	Variance 2017 vs 2015	
2017	SA	($4,671)	2017 projections lower by $4.6M mainly due to delay in the LRT project($5.0M) - only design work anticipated in 2017; construction t begin in 2018.
	SR	$143	Not Material
	SS	($1,868)	Variance due to lower Substation Upgrade costs - Webb Municipal Station deferred from 2017 to 2018.
	GP	($4,539)	Deferrals due to merger - ERP upgrade ($2.0M), other Engineering & Asset System Upgrades ($1.7M), and fleet ($0.4M).
	Total	($10,934)	

Year	Variance Breakdown & Comments		
	Category	Variance 2017 vs 2015	
2018	SA	($1,313)	Further delay in the LRT project by six months ($2.5M); partially offset by increased activity in Offers to Connect $0.7M, and Residential Service upgrades $0.3M.
	SR	$2,670	Increased spend for both UG and OH Transformer overhauls due to costs for fixing PCB/Leaking issues.
	SS	$292	Not Material
	GP	($3,609)	Mainly deferrral of JDE upgrade ($1.1M), Engineering & Asset Systems upgrade ($1.0M), and other projects (Meter Data Wahehouse, $500K; Business Intelligence for CC&B, $400; Customer Billing System Enhancements, $200K).
	Total	($1,959)	

Year	Variance Breakdown & Comments		
	Category	Variance 2017 vs 2015	
2019	SA	$766	Primarily higher Offer to Connect activity $0.7M.
	SR	$1,870	Increased spend for both UG and OH Transformer overhauls due to costs for fixing PCB/Leaking issues.
	SS	$582	Mainly higher spend projected for SCADA/Automation switch program.
	GP	($3,214)	Deferral of JDE Upgrade ($1.3M); Engineering & Asset Systems ($0.9M); and CISCO VoIP Phone System upgrade ($0.8M)
	Total	$4	

Year	Variance Breakdown & Comments		
	Category	Variance 2017 vs 2015	
2020	SA	1,705	Higher projections due to increase in Offers to Connect activity $0.7M, and higher LRT construction costs $0.7M.
	SR	2,950	Increased spend for both UG and OH Transformer overhauls due to costs for fixing PCB/Leaking issues.
	SS	612	Mainly higher spend projected for SCADA/Automation switch program.
	GP	(2,344)	Mainly deferral of JDE Upgrade ($1.6M); and Customer Billing & System Enhancements ($1.0M).
	Total	2,923	

Year	Variance Breakdown & Comments		
	Category	**Variance 2017 vs 2015**	
2021	**SA**	$4,515	Mainly due to LRT ($3.8) that had been delayed from 2017/18.
	SR	$1,670	Increased spend for both UG and OH Transformer overhauls due to costs for fixing PCB/Leaking issues.
	SS	$32	Not Material
	GP	($3,231)	Mainly deferral of JDE Upgrade ($1.4M); and Customer Billing & Web Self-Service Enhancements ($1.0M).
	Total	$2,986	

4.0-VECC-25

Reference(s): E2/T4/S11/Figure 2

a) Please explain the trend correlation between years 2014-2016 of zero or near zero cable failures in the months through January –March with the geometrical progression in the June through December months.

Response:

a) The values in E2/T4/S11/Figure 2 are provided in E3/T1/S1/A50 p. 362 Table 72. Figure 2 is a cumulative graph and does not display monthly outages. The majority of cable faults occur in the summer, or depending on the year, warmer months. From Table 72, May to August have over 10 outages year over year. September and October also have higher failure rates driven by cables surviving the summer peak but ultimately failing due to the stresses on the distribution system.

4.0-VECC-26

Reference(s): E2/T4/S11/pg.7

Pre-amble: At the above reference it states "[D]*ue to the high-density layout and emphasis on pedestrian-friendliness, Alectra Utilities is required to adopt underground designs for all downtown core electrical infrastructure*."

a) Please clarify – are the underground requirements mandated by legislation or municipal by-laws. If yes please specify.

Response:

a) The conditions for underground infrastructure in the downtown core are mandated by municipal guidelines and requirements. In addition, some of the existing legacy pole lines in the downtown core are currently being converted to an underground system as per the City of Mississauga requirements.

4.0-VECC-27

Reference(s): E2/T4/S11/pg.22/Table 135

a) Please explain the significant increase in Grounds and Buildings spending in the 2017-2022 period.

Response:

a) Please see Alectra Utilities' response to ERZ-SEC -17.

4.0-VECC-28

Reference(s): E2/T4/S11/pg.22

Pre-amble: In EB-2015-0065 Enersource provided the following vehicle replacement policy:

- **Light vehicles are replaced after three - five years, or 170,000 km**
- **Service trucks are replaced after five - eight years or 200,000 km**
- **Heavy equipment trucks are replaced after eight - 12 years, or after 230,000 km**
- **Work equipment is replaced on a condition based assessment.**
  (Source Supp-Staff-15/EB-2015-0065)

a) Do all of the vehicles being targeted for replacement meet (or are expected to meet) this policy?

Response:

a) The planned vehicle replacement criteria established above were based on existing best practices within and outside the industry, manufacture recommendations and vehicle conditions at that time. Many of the planned vehicle replacements for 2015 and 2016 did not take place due to financial constraints or from the merger due to fact that Management believed that by standardizing its fleet specifications and rationalizing its fleet requirements it could make better investments after the merger. As a result of deferring some of the purchases because of the merger, many of the vehicles that were planned for replacement must be replaced due to decreasing vehicle availability caused by more maintenance and repairs as well as increased safety concerns.

4.0-VECC-29

Reference(s): E2/T4/S11/Table 144

a) For each incremental eligible capital project shown in Table 144 please provide the expected capital contribution. Please also clarify whether the amounts shown in Table 144 are net of contributions.

Response:

a) The amounts provided in Table 144 are net of Contributions. Table 1 below provides the expected capital contributions for the ICM projects.

Table 1 – ICM Projects Capital Contribution

Enersource Rate Zone - ICM Projects	Gross Capital Expenditures	Customer Contribution	Net Capital Expenditures
Roads - QEW - Evans to Cawthra	$1,617,775	$323,555	$1,294,220
System Access	**$1,617,775**	**$323,555**	**$1,294,220**
OH Rebuild - Lake/John	$927,370	$0	$927,370
OH Rebuild - Church	$1,020,107	$0	$1,020,107
Subdivision Rebuild - Glen Erin & Montevideo - Section 1	$1,961,142	$0	$1,961,142
Credit Woodlands Crt/Wiltshire	$1,548,270	$0	$1,548,270
Tenth Line Main Feeder	$1,135,398	$0	$1,135,398
Folkway & Erin Mills Main Feeder	$1,032,180	$0	$1,032,180
Glen Erin & Battleford	$2,064,360	$0	$2,064,360
City Centre Drive Cable Renewal	$1,548,270	$0	$1,548,270
Leaking Transformer Replacement Project	$8,447,243	$0	$8,447,243
System Renewal	**$19,684,339**	**$0**	**$19,684,339**
Substation - York MS	$3,268,463	$0	$3,268,463
System Service	**$3,268,463**	**$0**	**$3,268,463**
Total Enersource Rate Zone Incremental Capital Funding	**$24,570,577**	**$323,555**	**$24,247,022**

4.0-VECC-30

Reference(s): E2/T4/S9, page 6
LRAMVA Work Form, Tab 2

a) Please provide references for the LRAMVA Thresholds set for the years 2014-2015 by customer class.
b) What was the last year of actual data used in developing the load forecast for EB-2012-0033 when the threshold for 2013-2015 was established?
c) Are the threshold values based on annualized savings consistent with the manner in which the IESO reports verified results?

Response:

a) The LRAMVA Thresholds set for the years 2014-2015 was included in the OEB's Decision and Order for the Enersource 2013 COS Application EB-2012-0033).

b) The last year of actual data used in developing the load forecast for the Enersource Cost of Service Application (EB-2012-0033) was 2011, when the threshold for 2013-2015 was established.

c) The threshold values based on annualized savings are consistent with the manner in which the IESO reports verified results.

In addition to continuing the existing DVA accounts, Enersource requested a new deferral account to capture costs for inspecting or certifying suite meters. However, this request was subsequently withdrawn in the company's Reply Argument

Board Findings

The Board approves the continuation of the existing accounts. The proposed new accounts are addressed elsewhere in this Decision.

LRAMVA

The Board in its Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) established that the Board would authorize a Lost Revenue Adjustment Variance Account ("LRAMVA") to capture, at the customer rate-class level, the difference between the level of CDM program activities included in the distributor's load forecast and the actual, verified impacts of authorized CDM activities between 2011 and 2014.

The cumulative CDM forecast by rate class to which the CDM actuals will be compared is shown in the table below.

Customer Class	2013 CDM Forecast
Residential	35,842,920
Small Commercial	-
Unmetered Scattered Load	-
GS < 50kW	39,519,293
GS 50kW- 499kW	6,718,613
GS 500kW - 4999 kW	7,166,687
GS Large Use (> 5000kW)	8,983,655
Street lighting	20,915,195
Total	119,146,362

Source: Exhibit 3 Tab 1 Schedule 2 p. 6 Table 3.

4.0-VECC-31

Reference(s): E2/T4/S9, page 4
Attachments 43 and 44

a) Please provide the excel versions of Attachments 29 and 30 as these are much easier to read/review.

Response:

a) Please see Alectra Utilities' response to ERZ-Staff-18.

4.0-VECC-32

Reference(s): E2/T4/S9, page 4
LRAMVA Work Form, Tab 7- Persistence Data

a) If not already provided, please provide an excel version of the IESO report regarding the persistence of 2011-2014 CDM program savings through to and including 2015.

Response:

a) The information is provided in a response to the OEB Staff Interrogatories, reference: ERZ-Staff-18.