ENERGY+ INC.

EB-2018-0028

Response to Interrogatories

Vulnerable Energy Consumers Coalition

(VECC)

September 14, 2018

Energy+ Inc.

Response to Interrogatories

Vulnerable Energy Consumers Coalition (VECC)

Table of Contents

Exhibit 1 - Administration and Customer Engagement

1-VECC-1

INTERROGATORY

Reference: E1/pgs.72-73, 98, 112

a) Please explain what specific customer feedback was provided that caused Energy+ to defer the additional third overhead feed line into the Town of Paris? (pg.98).

RESPONSE

In the Telephone Surveys and Online Workbook Portal, low-volume customers, in both the County of Brant and Cambridge and North Dumfries, consistently stated that they value delivering reasonable rates above all else. Satisfaction with system reliability was generally very high, with lower levels among business customers in the County of Brant. Customers in the County of Brant suggest that, next to lowering electricity rates, addressing power outages should be a priority.

Based on overall customer feedback for reasonable distribution rates, and given the high cost and technical challenges of adding a third feeder line into the Town of Paris, Energy+ will defer adding a third overhead feed line in favour of a less costly solution.

Instead of an additional third overhead feed line into Paris, Energy+ chose a lower cost, alternate solution that will connect lines to an existing Hydro One 27.6kV feeder in Paris. While this solution will not provide as much capacity as a completely new feed line, Energy+ believes that this is the best option, given customers' feedback related to delivering reasonable rates above all else, while addressing customer feedback with respect to reliability.

1-VECC-1

INTERROGATORY

Reference: E1/pgs.72-73, 98, 112

b) Please explain what the purpose of the “Service Order module” that was to be integrated into the My Account Online portal, but was subsequently deferred due to customer feedback (pg.112).

RESPONSE

The Service Order module (Service Connect) integrates with Energy+’s Customer Information and Billing System. Customers signed up for My Account Online, would have access to Service Connect, which would provide customers with the option to request and track service work orders, and receive notifications from Energy+ when the service work was completed. Customers could also use Service Connect to notify Energy+ of a Move, or any service-related issue, such as a tree on a line, or flickering lights.

The Service Order module could be used by a customer to stay up-to-date on any changes, with regard to a service request logged on the customer’s account through My Account Online. A customer could activate the notification function to receive a message instantly via email, SMS or telephone when the status of their service order changed.

Based on customer feedback relating to value-added services and reasonable distribution rates, Energy+ deferred the decision to implement the Service Order module. In its place, Energy+ has streamlined its online forms for customers to report a Move, report a problem or streetlight out. With the upgrade and improvements to the existing corporate website, the online forms will be “fully responsive” allowing customers the opportunity to use the existing online forms on mobile devices. When a customer completes an online form to report a Move, report a problem or streetlight out they receive a return notification that Energy+ is addressing their request.

1-VECC-2

INTERROGATORY

Reference: E1/pg.89

a) Please provide the calculation which supports the estimated typical cost of the planned new facilities of $0.68 per month per customer.

RESPONSE

The calculation which supports the estimated typical cost of the planned new facilities of $0.68 per month per customer is detailed in Table 1-VECC-2, below.

Table 1-VECC-2: Calculation of Customer Rate Impact of Planned New Facilities					
Southworks Development		**Annual**			
Incremental Operating Costs	A	$ 107,640	Based on Sq. Ft costs for Bishop St. Location		
Parking Costs		$ 150,000	Parking for 70 Employees		
		$ 257,640			
Less: Thompson Lease		-$ 57,904	Lease costs in 2019 @ $11.25 per sq. ft		
	B	$ 199,736			
			Useful Life	Annual Dep'n	
Estimated Capital Costs					
Land		$ -			
Building					
Structure		$ 3,600,000	80	$ 45,000	
Roofing		$ 280,000	20	$ 14,000	
Mechanical		$ 620,000	25	$ 24,800	
Office Furniture		$ -	10	$ -	
	C1	$ 4,500,000		$ 83,800	C2
Estimated Operating Costs, based on Bishop St. Operating Costs					
2016 Building Costs - Per Sq. Ft		$ 5.00			
Estimated Sq. Footage		21,528			
		$ 107,640.00	A		
Rate Base:					
Incremental OM&A		$ 199,736	B		
Working Capital		7.50%			
W/C Allowance		$ 14,980.22	D		
Capital Expenditures		$ 4,500,000	C		
W/C Allowance		$ 14,980	D		
Rate Base		$ 4,514,980			
Estimated Financing Capital Structure					
Debt @ 80%		$ 3,611,984	E		
Equity @ 20%		$ 902,996	F		
		$ 4,514,980			
Deemed Interest Rate		4.22%	G	Based on existing interest rates plus estimate for new debt % in 2019	
Deemed Interest		$ 152,426	H=E*G		
Deemed ROE		8.78%	I	Based on 2017 CoS Filers	
Allowable ROE		$ 79,283	J=F*I		
Revenue Requirement:					
Allowable ROE		$ 79,283	J		
PILs		$ 11,012	K	Computed at 12.5% (estimated current tax rate)	
Pre-tax Income		$ 90,295	L=J+K		
Allowable Expenses					
Interest (Deemed)		$ 152,426	H		
OM&A		$ 199,736	B		
Depreciation		$ 83,800	C2		
Total Allowable Expenses		$ 435,962	M=H+B+C2		
Total Distribution Revenue Requirement		$ 526,257	N=L+M	$ 24.45	Per square foot
Existing Approved Distribution Revenue Requirement		$ 32,928,000	O	2011 CoS (BCP) + 2014 CoS (CND)	
% Increase		1.60%	P=N/O		
Number of Customers		64,123	Q		
Annual Revenue Per Customer		$ 8.21	R=N/Q		
Monthly Revenue Required per Customer		$ 0.68	S = R/12		
Total Bill - Estimated using 2017 Distribution Rates - Avg. Res. 750 kWh		$ 126.43			
% Increase on Total Bill		0.5%			

1-VECC-3

INTERROGATORY

Reference: E1/pg.389

a) What was the total cost of the Innovative Research customer engagement activities and surveys?

RESPONSE

The total cost of the Innovative Research customer engagement activities and surveys was $163,856.26 + HST.

EXHIBIT 2 – RATE BASE AND CAPITAL EXPENDITURES

2-VECC-4

INTERROGATORY

Reference: Exhibit 2, Section 2.7.2.1, Table 2-29

a) Actual capital contributions in 2015 and 2016 were 56% and 50% respectively of system access costs. The equivalent average forecast for 2019 through 2022 is only 19%. Please explain why E+ is expecting capital contributions in the future to be a much lower portion of system access funding.

RESPONSE

Energy+ is expecting capital contributions in the future to be a much lower portion of system access funding due to i) the forecasted decline in Region of Waterloo/Municipality and Ministry of Transportation ("MTO") road restoration/relocation projects and ii) a change in classification of meter capital expenditures to general plant, both explained herein.

In 2015 and 2016 Energy+ had the following material road relocation projects (extracted from EB-2018-0028, Exhibit 2, Pages 59-61):

Table 2-VECC-4a)(i): 2015 & 2016 Road Relocation Projects

Projects	2015	2016
Reporting Basis	**MIFRS**	**MIFRS**
System Access		
Franklin Boulevard Roundabouts - Year 1	$ 1,792,761	
Franklin Boulevard Roundabouts - Year 2	$ 107,324	$ 127,897
Relocations - Various City/Township/Region Projects	$ 223,212	$ 144,007
Relocations - South Boundary Road (SBR) - Water St. S./SBR, Cheese Factory Rd./SBR		$ 448,252
Relocations - Fountain St./King St. (Region of Waterloo)		$ 384,608
Highway 401 Widening and Bridge Replacements	$ 288,286	$ 74,014
Munch Ave Relocations	$ 204,702	
Relocations - Shettleston Dr.	$ 135,191	
Relocations - Sheffield St.		$ 134,746
Material Road Relocation Projects	**$ 2,751,476**	**$ 1,313,524**

The average for 2015 and 2016 was $2,032,500.

The budgeted cost of road relocation projects from 2019 to 2022 is shown below (extracted from EB-2018-0028, Exhibit 2, Page 62).

Table 2-VECC-4-a)(ii): Road Relocation Capital Budget

Year	Capital Cost
2019	$ 766,600
2020	$ 548,900
2021	$ 977,000
2022	$ 629,800
Average	**$ 730,575**

The average for the four year period from 2019 to 2022 is $730,575.

Therefore, the average road relocation capital spending in the 2015/2016 period of $2,032,500 per year is forecasted to drop to an average of $730,575 in the four year period from 2019 to 2022. There are not as many road relocation projects expected based on consultations with the Municipalities, Region of Waterloo, and the MTO. This lowers the percentage of capital contributions from system access projects as road relocations have significant contributed capital.

The second factor that reduces the capital contributions in the future to a much lower portion of system access funding is the change to include meters in the system access budget instead of the previous general plant. The 2019 Test Year includes $751,092 in meter expenditures under system access. There is no contributed capital with respect to the meter capital expenditures. Therefore, the overall percentage of system access costs funded by contributed capital is lower.

See Response to Interrogatory 2-Staff-19 (a).

2-VECC-4

INTERROGATORY

Reference: Exhibit 2, Section 2.7.2.1, Table 2-29

b) Please explain how the capital contribution forecast was derived

RESPONSE

Energy+ derived the capital contribution forecast on a project-by-project basis during the budgeting process. Energy+ determined the expected level of capital contributions for each project in each year. The list of projects was determined with input from the Municipalities and the Ministry of Transportation Ontario (MTO).

2-VECC-4

INTERROGATORY

Reference: Exhibit 2, Section 2.7.2.1, Table 2-29

c) Please provide the actual capital contributions received in 2017.

RESPONSE

Capital contributions of $3,212,375 were recorded in 2017.

2-VECC-4

INTERROGATORY

Reference: Exhibit 2, Section 2.7.2.1, Table 2-29

d) Please provide the contributions for 2018 to date.

RESPONSE

Energy+ has recorded capital contributions for 2018 as at June 30, 2018 of $1,057,588.

2-VECC-5

INTERROGATORY

Reference: Exhibit 2, Appendix 2-AA

a) Please provide a progress update on the following projects including how much of the 2018 forecast budget has been spent to date:

   i) Fountain St. Relocations

   ii) Powerline Road

   iii) Servicing Industrial (underground)

   iv) Grand Ridge Drive

   v) Burtch Road

   vi) Cockshutt Road

RESPONSE

The updates on these projects are as follows:

i) Fountain St. Relocations

   The start date for the Fountain St. Relocations project has been deferred to 2019 or later based on updated information received from the Region of Waterloo with regards to the overall timing of the project. There has been $0 spent to date out of $1,170,000 capital budget amount.

ii) Powerline Road

   The Powerline Road from Rest Acres to Mill Hill Road Relocation project had a scope change which eliminated the underground conversion for Energy+. The project scope involves overhead relocation in conjunction with Hydro One. There has been $0 spent out of the $695,000 capital budget amount.

iii) Servicing Industrial (underground)

Servicing Industrial (underground) continues throughout the year. There has been $319,979 spent to date out of $1,193,500 capital budget.

iv) Grand Ridge Drive

The Grand Ridge Drive phase 2 underground rebuild project is currently underway. There has been $94,001 spent to date out of the $713,300 capital budget.

v) Burtch Road

The Burtch Road overhead line rebuild from West of Biggars Lane to Cockshutt Road will begin in late Q3 of 2018. There has been $363 spent to date out of the $611,000 capital budget.

vi) Cockshutt Road

There are two Cockshutt Road rebuild projects.

The Cockshutt Road from Sour Springs Road to River Road & McGill Road from Cockshutt Road to 2km West of Cockshutt Road overhead rebuild started in Q1 of 2018. There has been forestry work and engineering work completed with construction slated to start in September. There has been $50,784 spent to date out of the $964,000 capital budget.

The Cockshutt Road from Burtch Road to Sour Springs Road overhead line rebuild has been deferred to 2019 as another project was advanced to help address a capacity constraint area in the distribution system (Colborne Street East). There has been $33,629 spent to date out of the $635,800 capital budget which is pertaining to third party engineering design costs.

vii) Colborne Street East Rebuild (McBay to White Swan Rd).

The Colborne Street East Rebuild overhead line rebuild project was advanced to 2018 due to capacity constraints on the 8kV distribution lines resulting from load growth. Energy+ advanced two segments of this project into 2018 with an estimated capital cost of $1, 232,330. The Cockshutt Road from Burtch Road to Sour Springs overhead rebuild project

('Cockshutt') with an estimated budget of $635,800 was deferred to 2019 and the Cindy Avenue underground rebuild project ('Cindy') with an estimated budget of $281,000 was deferred to 2019. The deferral of both the Cockshutt and Cindy projects along with timing changes to some System Access projects will ensure Energy+ remains on track with respect to its overall 2018 planned capital budget.

2-VECC-6

INTERROGATORY

Reference: EB-2013-0116, 1.1-SEC-1 Response to Interrogatories, Feb 25, 2014

a) Please confirm that in E+'s last cost of service application, EB-2013-0016 (Cambridge North Dumfries) that CND underspent its OEB Approved 2010 base year budget by approximately 16% ($1.6 million).

RESPONSE

Energy+ confirms that the 2010 Actual Gross Capital Expenditures (excl. capital contributions) were $1,666,921 lower than the 2010 Board Approved amount, which is approximately 16% of the gross capital expenditures.

Energy+ provided a detailed explanation for the variance as part of EB-2013-0116, Exhibit 2, Tab 2, Schedule 4, Page 1 of 4 (a copy of which is attached as reference), whereby the majority of the variance was due to the timing of two large general plant expenditures: (i) $1MM CIS/Billing System completed in 2011; and (ii) $650,000 ERP Replacement completed in 2012.

2-VECC-6

INTERROGATORY

Reference: EB-2013-0116, 1.1-SEC-1 Response to Interrogatories, Feb 25, 2014

b) The following table was provided in EB-2013-0116 and shows the capital expenditure plan presented to the CND Board of Directors (dated January 18, 2013). Please provide the actual spending for these categories for the CND utility for the period 2013 through 2015.

Capital Investment Plan Summary

CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.							
CAPITAL EXPENDITURE FORECAST							
($'000)							
	2012	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Net Capital Expenditure	$ 13,343	$ 7,929	$ 18,820	$ 16,251	$ 11,400	$ 10,730	$ 26,720

RESPONSE

Energy+ notes that the table provided by VECC is the 2013 Capital Expenditure Plan that was initially provided to the CND Board on December 20, 2012 (EB-2013-0116, Response to Interrogatories 1.1-SEC-1, Pg. 119 through 154). The Capital Expenditure Plan based on the January 18, 2013 Presentation to the Board was contained on Page 117.

For purposes of responding to this interrogatory, Energy+ has utilized the January 18, 2013 Capital Expenditure Plan.

Commencing in 2013, the former CND revised its reporting of actual capital expenditures to align to the categories required by the OEB as part of the Distribution System Capital Plan Filing Requirements. As a result, Energy+ cannot easily categorize the actual expenditures based on the categories utilized in the January 18, 2013 Capital Expenditure Plan. Energy+ has presented the actual capital expenditures for the years 2013 to 2015 based on the revised categories, and has categorized the January 18, 2013 Capital Expenditure Plan to align to these categories for comparative purposes.

Table 2-VECC-6b), below provides the Actual Capital Expenditures for 2013 to 2015 for the former CND compared to the January 18, 2013 Capital Expenditure Plan.

Table 2-VECC-6b): Actual Capital Expenditures vs. Plan

1.

2-VECC-6(b)								
CND Capital Expenditures								
2013-2015 Capital Expenditure Forecast vs. Actuals ($000's)								
	Budget Presented to CND Board January 18, 2013 (Note 1)			**EB-2013-0116**				
	Budget 2013	**Budget 2014**	**Budget 2015**	**2013 Bridge** (Note 2)	**2014 Board Approved** (Note 3)	**Actual 2013**	**Actual 2014**	**Actual 2015**
Land and Buildings (Reclassified - See Below)	$ -	$ -	$ -			$ -	$ -	$ -
Transformer Station and Equipment	3	-	-			-	-	-
System Renewal								
Lines - Overhead - Rebuilt	7,160	7,182	4,100					
Lines - Underground - Rebuilt	2,200	2,260	1,800					
	9,360	9,442	5,900	7,089	5,229	7,678	3,880	5,006
System Access/System Service								
Lines - Overhead - New	4,910	1,930	2,100					
Lines - Underground - New	5,481	7,281	2,000					
Line Transformers	2,193	2,006	2,000					
	12,584	11,217	6,100	9,171	8,410	5,203	3,560	7,514
Sub-total Distribution System - Gross	21,947	20,659	12,000	16,260	13,639	12,881	7,440	12,520
General Plant								
Land and Buildings	$ 483	$ 5	$ 100	448	55	388	219	80
Meters	915	887	500	915	967	649	277	197
Office Equipment and Furniture	141	-	50	187	80	161	59	9
Information Technology	1,153	411	500	609	2,086	609	1,373	1,502
Vehicles	592	925	700	588	520	576	462	611
Tools and Equipment	46	20	50	117	109	68	38	46
Sub-total General Plant	3,330	2,248	1,900	2,864	3,817	2,063	2,428	2,445
Gross Capital Expenditure	25,277	22,907	13,900	19,124	17,456	14,944	9,868	14,965
Less: Contributed Capital / Subdivisions Assumed	(7,072)	(7,406)	(3,000)	(3,041)	(2,406)	(2,880)	(500)	(4,207)
Net Capital Expenditure	$ 18,205	$ 15,501	$ 10,900	$ 16,083	$ 15,050	$ 12,064	$ 9,368	$ 10,758

Notes:
(1) EB-2013-0116, Response to Interrogatories 1.1-SEC-1, Pg. 117
(2) EB-2013-0116, Exhibit 2, Table 2-15 and Table 2-16 (General Plant)
(3) EB-2013-0116, Decision and Order, Settlement Proposal, April 2, 2014, Appendix C Capital Expenditures, Pg. 24 of 30.

2-VECC-7

INTERROGATORY

Reference:

a) Please provide the total annual capital expenditures for BCP for each year 2012 through 2015.

RESPONSE

Energy+ has provided the total annual gross capital expenditures for BCP for each year 2012 through 2015 in the Table 2-VECC-7a), below. Please refer to Exhibit 2, Appendix 2-BA for BCP Fixed Asset Continuity Schedule for each year.

Table 2-VECC-7a): BCP Capital Expenditures

Summary of Annual Capital Expenditures for BCP 2012 through 2015					
	2012	2013 Old CGAAP	2013 New CGAAP	2014 New CGAAP/ MIFRS	2015 New CGAAP/ MIFRS
Capital Expenditures	$ 3,707,619	$ 2,438,976	$ 2,287,723	$ 2,377,721	$ 2,296,121

2-VECC-7

INTERROGATORY

Reference:

b) Please provide the total capital contributions for BCP for each year 2012 through 2015.

RESPONSE

Energy+ has provided the total annual capital contributions for BCP for each year 2012 through 2015 in Table 2-VECC-7b), below.

Table 2-VECC-7b): BCP Capital Contributions

Summary of Annual Capital Contributions for BCP 2012 through 2015					
	2012	2013 Old CGAAP	2013 New CGAAP	2014 New CGAAP/ MIFRS	2015 New CGAAP/ MIFRS
Capital Contributions	$ (49,480)	$ (59,601)	$ (59,601)	$ (255,698)	$ (289,909)

2-VECC-8

INTERROGATORY

Reference: Exhibit 2, Section 2.7.3.2 & appendix N: Facilities Business Plan, pg. 1032

a) Please provide the square footage per management/ administration FTE and separately for operations and maintenance FTEs before and after the relocations.

RESPONSE

Please see Table 2-VECC-8a)(i), below for the square footage per management/ administration FTE and separately for operations and maintenance FTEs before the relocations. Please see Table 2-VECC-8a)(ii), below for the square footage per management/ administration FTE and separately for operations and maintenance FTEs after the relocations. CDM staff (5) are included in the calculations in both tables.

Please note that the increase in square foot per FTE for administrative includes vacant space that would be utilized in the event of a merger or acquisition, or could be leased to a third party. Administrative staff would be consolidated at the Southworks Facility, while most Operations staff would remain near the partner distributor in order to provide good customer service.

Table 2-VECC-8a)(i): Square Footage Per FTE – Before Relocations

Type of Staff	Administrative	Operations	Total
Facilities Square Feet	23,336	49,294	72,630
Number of FTEs	61	75	136
Square Foot Per FTE	383	657	534

Table 2-VECC-8a)(ii): Square Footage Per FTE – After Relocations

Type of Staff	Administrative	Operations	Total
Facilities Square Feet	37,724	50,519	88,243
Number of FTEs	61	75	136
Square Foot Per FTE	618	674	649

2-VECC-8

INTERROGATORY

Reference: Exhibit 2, Section 2.7.3.2 & appendix N: Facilities Business Plan, pg. 1032

b) Why is the sq. ft. per customer as shown in Figure 1 of the Facilities Plan a relevant metric of space needs?

RESPONSE

Energy+ considers the square feet of facilities space per customer a measure of efficiency. The lower the square feet per customer, the more cost effective it is for customers.

Figure 1 shows a steady decline in facilities space per customer for more than 20 years. The metric only increases when space needs to be leased at the Thompson Drive building (i.e. increased square feet) and when BCP is acquired (i.e. increased square feet and increased customers).

2-VECC-8

INTERROGATORY

Reference: Exhibit 2, Section 2.7.3.2 & appendix N: Facilities Business Plan, pg. 1032

c) Does the sq. ft. per employee as shown by the black line in Figure 1 show the final figure once all new facilities are in place (i.e. 2020)? If not please extend the table to show the final figures once all new facilities completed.

RESPONSE

Energy+ confirms that the black line in Figure 1 shows the final square foot per employee once all new or renovated facilities are in place.

2-VECC-9

INTERROGATORY

Reference: Exhibit 2, Section 2.7.3

a) In what year was 65 Dundas building ($1.5) removed from the continuity schedules of Energy+?

RESPONSE

Energy+ removed the net book value of the 65 Dundas land and building from the continuity schedule in 2018. The net book value amounts removed were $87,795 land and $297,429 building. Please refer to Exhibit 9 and Response to Interrogatory 9-Staff-103.

2-VECC-10

INTERROGATORY

Reference: Exhibit 2, DSP, pg. 138

a) Please provide the customer interruption hours by cause code as shown in Table 206 but separately for BCP and CND for the year 2014 and 2015.

RESPONSE

Table 2-VECC-10, below shows a breakdown of Table 2-6 for customer interruption hours by cause code broken out separately for BCP and CND for years 2014 and 2015.

Table 2-VECC-10: Customer Interruptions by Cause Code – CND and Brant

Customers Hours Lost by Cause				
Cause	**CND Area**		**Brant Area**	
	2014	**2015**	**2014**	**2015**
0 - Unknown/Other	1,503.7	2,409.3	10.0	78.8
1- Scheduled	6,476.9	10,442.3	240.0	5.0
2 - Loss of Supply	2,763.4	5,059.5	5,669.0	7,071.0
3 - Tree Contacts	11,249.1	12,768.3	16,607.0	449.8
4 - Lightning	770.5	283.3	0.0	42.8
5 - Defective Equipment	6,932.0	20,022.1	4,548.0	434.9
6 - Adverse Weather	12.7	4,801.3	5,646.0	0.0
7 - Adverse Environment	0.0	0.0	53.0	2.3
8 - Human Element	0.0	171.0	0.0	0.0
9 - Foreign Interference	6,732.5	6,739.9	56.0	2,249.4

2-VECC-11

INTERROGATORY

Reference: Exhibit 2, DSP, pgs. 218, 271

a) Figure 4-16 shows the impact of the system investment is to actually increase slightly OM&A costs. Please explain why this would be the case give that the average system renewal spending will rise during 2019-22 period to $8,154,223 from the 2014-2018 average system renewal spending of $6,694,000 (Appendix 2-AB).

RESPONSE

The Operations and Maintenance expenditures, based on the 2014 Board Approved Proxy (Exhibit 4, Appendix 2-JA) were $5,890,444. The 2019 Test Year O&M is $5,930,641 or $40,197 – a 0.68% increase over the past five years.

Energy+ would also note that the O&M expenditures include $182,968 increase between the 2019 Test Year and the 2014 Board Approved Proxy related to the transition to a 24/7 Control Room, which necessitates additional Control Room staff. Please refer to Exhibit 4, Section 4.3.3, Page 42.

Excluding the impact of the incremental costs associated with the 24/7 Control Room, and recognizing the annual wage increases, Energy+ submits that O&M costs have decreased as a result of the expenditures that have occurred with respect to system renewal.

2-VECC-12

<u>INTERROGATORY</u>

<u>Reference: Exhibit 2, 2017 Asset Condition Assessment</u>

a) For each asset category listed in Figure 5, the Health Index Results please provide the following:

  a) total population of assets;

  b) total population of assets physically tested;

  c) description of physical test as per response to b);

  d) total population of assets only visually inspected

<u>RESPONSE</u>

The requested information is shown in Table 2-VECC-12, below.

Table 2-VECC-12: Asset Type Information

Asset Type	Total Population	Total Population of Assets Physically Tested	Description of Physical Test	Total Population of Assets Only Visually Inspected See Note # 3
Station Transformers - Combined	4	4	Power Factor, Surge Arresters, Excitation, Transformer Turns Ratio, Resistance Tests, Oil Tests	0
Station Transformers Main Tank	4	4	Power Factor, Surge Arresters, Excitation, Transformer Turns Ratio, Resistance Tests, Oil Tests	0
Station Transformers LTC	4	4	Oil Tests	0
Station Circuit Breakers	17	17	Contact Resistance, Insulation Resistance, Protection Tests (Relays)	0
Voltage Regulators	6	0	N/A	6
Capacitors	18	0	N/A	18
OH Line Switches	387	0	N/A	387
OH Line Reclosers	15	0	N/A	15
Pole Mounted Transformers 1-PH	3727	0	N/A	3727
Pole Mounted Transformers 3-PH	1995	0	N/A	1995
Wood Poles (Brant)	6956	4920	Drilling	2036
Wood Poles (Cambridge)	12746	4106	Drilling	8640
Concrete Poles	1625	0	N/A	1625
Steel Poles	347	0	N/A	347
Pad Mounted Transformers 1-PH	3268	0	See Note # 1	3268
Pad Mounted Transformers 3-PH	541	0	See Note # 1	541
Pad Mounted Switchgear	67	0	N/A	67
Vault Transformers	55	0	See Note # 1	55
Submersible Transformers	102	0	See Note # 1	102
UG Primary Cables (KM) Brant 1-PH	72	0	N/A	See Note # 2
UG Primary Cables (KM) Brant 3-PH	31	0	N/A	See Note # 2
UG Primary Cables (KM) Cambridge 1-PH	371	0	N/A	See Note # 2
UG Primary Cables (KM) Cambridge 3-PH	170	0	N/A	See Note # 2

Note # 1 - Energy+ electrically tests all new transformers before they are deployed in the field. Energy+ also electrically tests any transformers removed from the field before they are re-deployed.
Note # 2 - Underground cables cannot be visually inspected.
Note # 3 - Energy+ conducts annual inspections for 1/3 of its distribution system through line patrols.

2-VECC-13

INTERROGATORY

Reference: Exhibit 2, Asset Condition Assessment, pg. 845

a) Table 2 (Summary of Flagged for Action) describes the replacement strategy for wood poles as proactive and reactive. Is the policy of a proactive strategy to replace wood poles a departure from Energy+'s (CND) previous distribution system plan. If yes, please explain the reason for the change in policy.

RESPONSE

No, the policy of proactively replacing wood poles is not a departure from Energy+'s (CND) previous distribution system plan. In the previous Distribution System Plan (DSP), CND stated that by renewing old and failing plant, it is expected that fewer poles will need to be replaced on a reactive maintenance basis (Page 14 of DSP dated Sept 28, 2013). Wood poles are replaced on a proactive basis in the case of overhead line rebuilds or spot pole replacements, and reactively when poles fail unexpectedly.

2-VECC-14

INTERROGATORY

Reference: Exhibit 2, Tables 2-24 and 2-25

a) Please provide a schedule that sets out the calculation of the $78,123,704 forecast for Power Purchase costs.

RESPONSE

Table 2-VECC-14, below outlines the calculation of the power purchase forecast of $79,123,704 in Table 2-24.

Please refer to the response to Interrogatory 1-Staff-9 a-I for the calculation to the revised power purchase costs.

Table 2-VECC-14: Calculation of Power Purchase Forecast

Rate Class	RPP / Non RPP	2019 Forecasted kWh/kW	2019 Loss Factor	Customer Percentage	Uplifted kWh/kW	COP Rates	Total Cost
Residential	RPP	466,068,279	1.0287	97.02%	465,180,396	$0.08192	$38,109,209
Residential	Non RPP	466,068,279	1.0287	2.98%	14,285,466	$0.02279	$325,615
GS<50kW	RPP	195,276,256	1.0287	85.13%	171,026,454	$0.08197	$14,019,656
GS<50kW	Non RPP	195,276,256	1.0287	14.87%	29,863,207	$0.02301	$687,129
General Service > 50 to 999 kW	RPP	493,112,062	1.0287	9.95%	50,498,389	$0.07694	$3,885,131
General Service > 50 to 999 kW	Non RPP	493,112,062	1.0287	90.05%	456,788,657	$0.02292	$10,471,779
General Service > 1000 to 4999 kW	RPP	231,017,192	1.0185	1.15%	2,711,058	$0.00000	$0
General Service > 1000 to 4999 kW	Non RPP	231,017,192	1.0185	98.85%	232,570,367	$0.02310	$5,372,570
Large Use	RPP	145,503,126	1.0045	0.00%	-	$0.00000	$0
Large Use	Non RPP	145,503,126	1.0045	100.00%	146,157,890	$0.02281	$3,333,861
Unmetered Scattered Load	RPP	2,273,988	1.0287	90.71%	2,122,035	$0.08567	$181,804
Unmetered Scattered Load	Non RPP	2,273,988	1.0287	9.29%	217,321	$0.01209	$2,628
Sentinel Lighting	RPP	126,989	1.0287	42.08%	54,967	$0.08429	$4,633
Sentinel Lighting	Non RPP	126,989	1.0287	57.92%	75,673	$0.02344	$1,774
Street Lighting	RPP	5,367,464	1.0287	3.01%	166,097	$0.08311	$13,805
Street Lighting	Non RPP	5,367,464	1.0287	96.99%	5,355,660	$0.02273	$121,713
Embedded WNH	RPP	58,104,381	1.0287	0.00%	-	$0.00000	$0
Embedded WNH	Non RPP	58,104,381	1.0287	100.00%	59,774,648	$0.00000	$0
Embedded HON	RPP	12,605,162	1.0287	0.00%	-	$0.08200	$0
Embedded HON	Non RPP	12,605,162	1.0287	100.00%	12,967,510	$0.02281	$295,789
Embedded Distributor	RPP	347,757	1.0185	0.00%	-	$0.08200	$0
Embedded Distributor	Non RPP	347,757	1.0185	100.00%	354,176	$0.02281	$8,079
Embedded Distributor	RPP	12,191,720	1.0185	0.00%	-	$0.08200	$0
Embedded Distributor	Non RPP	12,191,720	1.0185	100.00%	12,416,761	$0.02281	$283,226
Embedded Distributor	RPP	43,274,122	1.0185	0.00%	-	$0.08200	$0
Embedded Distributor	Non RPP	43,274,122	1.0185	100.00%	44,072,897	$0.02281	$1,005,303
Total							**$ 78,123,704**

<u>2-VECC-14</u>

<u>INTERROGATORY</u>

<u>Reference: Exhibit 2, Tables 2-24 and 2-25</u>

b) If Embedded Distributor-Waterloo North is included in the calculation (as Table 2-25 suggests), please explain why since it is a WMP (per Exhibit 3, page 26).

<u>RESPONSE</u>

Energy+ confirms that the Embedded Distributor-Waterloo North is not included in the calculation.

2-VECC-14

INTERROGATORY

Reference: Exhibit 2, Tables 2-24 and 2-25

c) Please explain how the volumes for each customer class used to calculate the Global Adjustment were determined.

RESPONSE

The volumes for each customer class used to calculate the Global Adjustment were based on the 2019 Load Forecast. Please refer to the Response to Interrogatory 1-Staff-9 a-i for the calculation of the Global Adjustment.

EXHIBIT 3 - REVENUES

3-VECC-15

INTERROGATORY

Reference: **Exhibit 3, pages 9 and 11 (Tables 3-5 and 3-7)**

Exhibit 3, pages 4 and 19

Load Forecast Model, Rate Class Customer Model Tab

Preamble: **At page 4, lines 8-12, E+ states that revenue figures for 2017 are a forecast based on 11 months of actual data.**

a) Please explain how the historical annual customer/connection count for each class was calculated (e.g., year-end values, average of 12 months, etc.).

RESPONSE

The historical annual customer/connection count for each class was calculated by adding the previous year-end value to the current year-end value and dividing the result by two.

3-VECC-15

INTERROGATORY

Reference: Exhibit 3, pages 9 and 11 (Tables 3-5 and 3-7)

Exhibit 3, pages 4 and 19

Load Forecast Model, Rate Class Customer Model Tab

Preamble: At page 4, lines 8-12, E+ states that revenue figures for 2017 are a forecast based on 11 months of actual data.

b) For purposes of the Rate Class Customer Model Tab, please confirm whether the 2017 customer counts are based on 12 months of actual data. If not, please update the load forecast using 12 months of actual 2017 customer count data

RESPONSE

Energy+ confirms that the 2017 customer counts are based on 12 months of actual data.

3-VECC-16

INTERROGATORY

Reference: Exhibit 3, page 4 (lines 8-12) and page 6 (lines 9-10)

Load Forecast Model, Purchased Power Model and Rate Class

Energy Model Tabs

Preamble: At page 4, lines 8-12, Energy+ states that revenue figures for 2017 are a forecast based on 11 months of actual data. At page 6 (lines 9-10), Energy+ state that the regression analysis used actual data up to the end of 2017.

a) Please confirm that, for purposes of the regression analysis used to predict weather normal purchases (Purchased Power Model Tab), 12 months of actual 2017 purchased power data was available and used. If not, please re-estimate the models and provide an updated load forecasts based on 12 months of actual 2017 purchased power data.

RESPONSE

Energy+ confirms that for purposes of the regression analysis, 12 months of actual 2017 purchased power data was available and used.

3-VECC-16

INTERROGATORY

Reference: Exhibit 3, page 4 (lines 8-12) and page 6 (lines 9-10)

Load Forecast Model, Purchased Power Model and Rate Class Energy Model Tabs

Preamble: At page 4, lines 8-12, Energy+ states that revenue figures for 2017 are a forecast based on 11 months of actual data. At page 6 (lines 9-10), Energy+ state that the regression analysis used actual data up to the end of 2017.

b) For purposes of the Rate Class Energy Model Tab, please confirm whether the 2017 energy use by customer class is based on 12 months of actual data. If not, please update the load forecast using 12 months of actual 2017 data.

RESPONSE

Energy+ confirms that for purposes of the Rate Class Energy Model Tab the 2017 energy use by customer class is based on 12 months of actual data.

3-VECC-17

INTERROGATORY

Reference: Exhibit 3, pages 7 and 15

Preamble: At page 15 Energy+ indicates that a cogeneration facility began operation at the start of 2016. Table 3-3 (page 7) shows a drop in billed load in both 2016 and 2017.

a) If the 2017 data in Table 3-3 is not based entirely on actuals, please provide a revised table that is.

RESPONSE

Since the 2017 data in Table 3-3 is based entirely on actuals, there is no need to provide a revised table.

b) What wee the kWh provided by the co-generatin facility ean each of 2016 and 2017?

RESPONSE

The co-generation facility provided **REDACTED** kWh in 2016 and **REDACTED** kWh in 2017

3-VECC-18

INTERROGATORY

Reference: Exhibit 3, pages 14, 21 and 25

Load Forecast Model, Purchased Power Model Tab

a) At page 25 Energy+ indicates that it only has kW and not the kWh associated with the WMPs. However, in Column C of the Purchase Power Model, historical monthly kWh values are set out for the WMPs. Please reconcile.

RESPONSE

Energy+ is unable to find in Exhibit 3, page 25 where it is indicated that it only has kW and not the kWh associated with the WMPs. On page 25 it states:

There are a number of Energy+ customers/connections that are charged volumetric distribution on a per kW basis. This includes Wholesale Market Participants ("WMP"). However, WMPs only have kW associated with them since there are no charges to them from Energy+ that are based on kWh.

The above statement does not indicate that Energy+ does not have the kWh associated with the WMPs.

3-VECC-18

INTERROGATORY

Reference: Exhibit 3, pages 14, 21 and 25

Load Forecast Model, Purchased Power Model Tab

b) Please clarify what is included in Column B of the Purchased Power Model Tab and the sources of the data used to derive the values.

RESPONSE

Column B of the Purchased Power Model Tab includes the usage for the WMPs that were not WMP prior to 2013. The source of data is the Energy+ billing system.

3-VECC-18

INTERROGATORY

Reference: Exhibit 3, pages 14, 21 and 25

Load Forecast Model, Purchased Power Model Tab

c) Does Energy+ have any Fit or microFIT installations in its service area? If yes, please provide a schedule setting out the annual purchases for the period 2008-2017

RESPONSE

Yes, Energy+ has Fit and microFIT installations in its service area. Energy+ has provided the following Table 3-VECC-18c) for the annual purchases for the period of 2012-2017, based on the available information.

Table 3-VECC-18c): Embedded Generation

Energy+ Embedded Generation	
Year	kWh
2012	5,714,465
2013	8,429,697
2014	10,767,494
2015	15,648,011
2016	19,418,416
2017	19,213,267
Total	**79,191,350**

Energy+(CND) Embedded Generation	
Year	kWh
2012	5,510,021
2013	7,201,400
2014	9,263,239
2015	13,356,972
2016	16,828,325
2017	15,885,967
Total	**68,045,924**

Energy+(BCP) Embedded Generation	
Year	kWh
2012	204,444
2013	1,228,297
2014	1,504,255
2015	2,291,039
2016	2,590,091
2017	3,327,299
Total	**11,145,426**

3-VECC-18

INTERROGATORY

Reference: Exhibit 3, pages 14, 21 and 25

Load Forecast Model, Purchased Power Model Tab

d) If the response to part (c) is yes, were these purchases included in the "total system purchased energy" for purposes of estimating the regression model (i.e., Column F of the Purchased Power Model Tab)

RESPONSE

Energy+ confirms that the purchases were included in "total system purchased energy" for purposes of estimating the regression model.

3-VECC-18

INTERROGATORY

Reference: Exhibit 3, pages 14, 21 and 25

Load Forecast Model, Purchased Power Model Tab

e) If the FIT/microFIT purchases were not included in the total system purchased energy please provide a revised load forecast (i.e. excel model similar to current filing) where the total of IESO plus FIT/microFIT purchases is used as the dependent variable.

RESPONSE

Not applicable.

3-VECC-18

INTERROGATORY

Reference: Exhibit 3, pages 14, 21 and 25

Load Forecast Model, Purchased Power Model Tab

f) Based on the formula used to determine Column F of the Purchased Power Model Tab it appears that the load associated with WMPs served by Energy+ is excluded from the Purchased Power actual data used. Please confirm if this is the case. If not please explain the derivation of Column F.

RESPONSE

The load associated with WMPs served by Energy+ is excluded from the Purchased Power actual data used.

3-VECC-19

INTERROGATORY

Reference: Exhibit 3, page 15

Preamble: The regression model is set out at page 15 and the coefficient for CDM Activity is -0.30.

a) Please confirm that, based on Energy+'s proposed load forecast model, a 1 kWh increase in CDM activity will result in a 0.3 kWh decrease in purchased power.

RESPONSE

Energy+ updated the load forecast to include 2017 CDM actual results. The updated load forecast is provided in working Microsoft Excel format in the file named 2019 EnergyPlus Load Forecast Model_3 VECC 19 a). When the 2017 CDM actual results were included in the CDM Activity variable, the variable became statistically insignificant when the regression analysis was re-run. As a result, the CDM Activity variable has been removed as a variable in the regression analysis supporting the load forecast.

3-VECC-19

INTERROGATORY

Reference: Exhibit 3, page 15

Preamble: The regression model is set out at page 15 and the coefficient for CDM Activity is -0.30.

b) Please explain how/why this result is considered to be intuitively correct. Wouldn't one intuitively expect the coefficient to be reasonably close to -1.0, recognizing that there would also be a need to allow for losses?

RESPONSE

The assertion that the coefficient would be reasonably close to -1 is no longer applicable due the explanation provided in part a), above.

3-VECC-19

INTERROGATORY

Reference: Exhibit 3, page 15

Preamble: The regression model is set out at page 15 and the coefficient for CDM Activity is -0.30.

c) Did Energy+ test a load forecast model specification where the dependent variable was purchases plus CDM savings?

i. If yes, please provide both the model results and the resulting forecast.

ii. If no, please provide an alternative load forecast model that:

1) As the dependent variable, uses the Power Purchases (per the current model) – adjusted for FIT and micro/FIT purchases if required – but also adds to this value the monthly CDM activity values (adjusted by the annual loss factor for the year concerned).

2) As the independent explanatory variables, uses the same variables as the current model – excluding the CDM activity variable.

ii. If no, please provide a forecast of power purchases for 2019 by:

- Using the model developed per part (ii) and the currently forecast values for the independent variables (excluding CDM activity) to obtain an initial forecast for 2018 and 2019.
- Adjusting the total CDM activity results shown in Table 3-10 for 2018 and 2019 by the average historical loss factor (2.82% per page 18).
- Adjust the initial forecasts for 2018 and 2019 by the total (loss adjusted) CDM activity values.

RESPONSE

Energy+ did not test a load forecast model specification where the dependent variable was purchases plus CDM savings.

The alternative load forecast model is provided in working Microsoft Excel format in file named 2019 EnergyPlus Load Forecast Model_3 VECC 19 c).

3-VECC-20

INTERROGATORY

Reference: Exhibit 3, page 18

Load Forecast Model, Purchased Power Model Tab

a) What exactly does the unemployment variable used in the regression analysis represent?

b) Please confirm that for the forecast years (2018 and 2019) Energy+ used the average unemployment for 2017 as the value for all months. If not confirmed, what was basis for the forecast values used for unemployment?

c) Is Energy+ aware of any forecasts of unemployment for 2019 for the Kitchener-Waterloo area (either levels or percentages)? If yes, please provide. If not, please provide any forecasts for 2019 Energy+ is aware for Ontario unemployment (either levels or percentages).

RESPONSE

a) The unemployment variable used in the regression analysis represents the number of people of the labour force in the Kitchener-Waterloo-Barrie area that are unemployed in the referenced month. The number is shown in thousands. As an example, the value of 34.6 in January 2008 means there were 34,600 people unemployed in that month in the Kitchener-Waterloo-Barrie area.

b) The forecast years (2018 and 2019) Energy+ used the average unemployment for 2017 as the value for all months.

c) Energy+ is not aware of any forecasts of unemployment for 2019 for the Kitchener-Waterloo area. Energy+ did a “Google” search and was able to find a 2019 forecast for Ontario unemployment. The forecast from TD Economic as of June 19, 2018 indicates an unemployment rate of 6.0% for 2019.

3-VECC-21

INTERROGATORY

Reference: Exhibit 3, page 16 (Table 3-10)

a) Please provide the reports (i.e., for CND and Brant County) from the OPA/IESO that support the 2006-2010 CDM results set out in Table 3-10.

RESPONSE

The reports (i.e., for CND and Brant County) from the OPA/IESO that support the 2006-2010 CDM results set out in Table 3-10 are provided in working Microsoft Excel format under files named 2016-2010 Final OPA CDM Results Brant County Power Inc. 3-VECC-21 a) and 2016-2010 Final OPA CDM Results Cambridge and North Dumfries Hydro Inc. 3-VECC-21 a.

3-VECC-21

INTERROGATORY

Reference: Exhibit 3, page 16 (Table 3-10)

b) Energy+ has provided a copy of the 2011-2014 CDM Persistence Report for Brant County (Excel File). However, a similar report for Cambridge North Dumfries does not appear to have been provided. Please provide.

RESPONSE

The Cambridge North Dumfries version of the CDM Persistence Report has been provided in working Microsoft Excel format under file named 2011-2014 Final Results Report_HCCambridge and North Dumfries Hydro Inc 3-VECC-21 b.

3-VECC-21

INTERROGATORY

Reference: Exhibit 3, page 16 (Table 3-10)

c) Please explain how the 2017 Program values for 2017-2019 were derived from the Excel File – EnergyPlus_01_2018_Participation and Cost Report

RESPONSE

The 2017 information has been revised in the updated load forecast provided in 3 VECC 19 a) to reflect the 2017 Final Verified CDM Results Report.

3-VECC-21

INTERROGATORY

Reference: Exhibit 3, page 16 (Table 3-10)

d) Please confirm that 2017 Final Verified CDM Results Report for Energy+ is now available from the IESO and provide a copy.

RESPONSE

The 2017 Final Verified CDM Results Report for Energy+ has been submitted in response to IR 4-Staff-71 e).

3-VECC-21

INTERROGATORY

Reference: Exhibit 3, page 16 (Table 3-10)

e) Based on the 2017 Final Verified CDM Results Report:

i. Are any revisions required to Table 3-10?

ii. If yes, please provide a revised version.

iii. If yes, please provide a revised Load Forecast.

iv. If yes, please provide revised LRAMVA values (i.e., Table 3-24)

RESPONSE

Based on the 2017 Final Verified CDM Results Report:

i. A revised Table 3-10 is provided below

ii. As above.

iii. A revised Load Forecast is provided in 3 VECC 19 a. However, in the revised load forecast the CDM Activity variable has been deleted since it is no longer statistically significant which makes the information in Table 3-10 below irrelevant.

iv. A revised Table 3-24 is provided below

Table 3-10: CDM Activity Variable Supporting Data

Year	OPA Annual CDM Results 2006 to 2010 programs (kWh)	IESO/OPA Annual CDM Results 2011 to 2014 programs (kWh)	IESO Annual CDM Results 2015 programs (kWh)	IESO Annual CDM Results 2016 programs (kWh)	IESO Annual CDM Results 2017 programs (kWh)	Total Annual CDM Results (kWh)
2006	2,199,695	0		0	0	2,199,695
2007	5,865,381	0	0	0	0	5,865,381
2008	8,715,686	0	0	0	0	8,715,686
2009	14,062,057	0	0	0	0	14,062,057
2010	19,632,401	0	0	0	0	19,632,401
2011	23,543,736	6,993,904	0	0	0	30,537,640
2012	23,185,906	19,010,177	0	0	0	42,196,083
2013	23,093,273	29,756,733	0	0	0	52,850,006
2014	22,519,904	45,730,999	0	0	0	68,250,903
2015	20,225,485	55,118,689	10,515,310	0	0	85,859,483
2016	19,336,761	54,157,230	20,981,651	8,714,054	0	103,189,696
2017	16,614,719	52,313,262	20,698,092	17,428,107	16,410,757	123,464,936
2018	13,279,279	51,465,422	20,605,060	17,454,763	30,494,190	133,298,713
2019	7,609,615	50,830,908	20,593,543	17,454,763	30,486,756	126,975,585

Table 3-24: 2019 LRAMVA Threshold

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Large User	Street Lights	Total
2019 kWh	23,915,258	6,999,588	9,916,083	8,166,186	1,749,897	7,582,887	58,329,899
2019 kW - Annual			31,295	19,165	3,989	21,852	76,300
2019 kW - Monthly			2,608	1,597	332	1,821	6,358

3-VECC-22

INTERROGATORY

Reference: Exhibit 3, pages 19-21

Load Forecast Model, Rate Class Customer Model Tab

a) Do the customer counts set out in Table 3-13 and used in the derivation of the values in Tables 3-14 to 3-16 include the WMPs?

b) Do the kWh values by customer class used to determine the 2017 actual average usage per customer (Table 3-16) include the usage of the WMPs

c) If both the customer counts and usage values do not exclude the WMPs, please provide revised tables that do and a revised load forecast.

RESPONSE

a) The customer counts set out in Table 3-13 and used in the derivation of the values in Tables 3-14 to 3-16 exclude the WMPs.

b) The kWh values by customer class used to determine the 2017 actual average usage per customer (Table 3-16) exclude the usage of the WMPs

c) Not applicable.

3-VECC-23

INTERROGATORY

Reference: Exhibit 3, pages 22-23

Exhibit 7, page 10

d) Please provide copy of the 2015-2020 CDM Plan for Energy referenced on page 22. Please confirm that this is the most recent CDM Plan approved by the IESO and, if not, provide the most current approved Plan.

RESPONSE

The most recent approved CDM plan was approved by the IESO on May 16, 2018. The most recent plan and the approval letter are attached as Appendix 3-VECC-23d).

3-VECC-23

INTERROGATORY

Reference: Exhibit 3, pages 22-23

Exhibit 7, page 10

e) Is the new load displacement generation referenced at Exhibit 3, page 22 (lines 15-17), the same facility as discussed in Exhibit 7 (page 10) and for which a "cogeneration facility flag" was included in the Purchased Power Model?

i. If no, when is this additional load displacement generation expected to go into service and is this "load displacement generation" contributing to Energy+'s 2015-2020 CDM Plan?

ii. If yes, please confirm that by using a "cogeneration facility flag" in the purchased power model and the average use in 2017 to determine class loads, the Application has already accounted for the load reduction associated with the load displacement generation.

iii. If yes, is any portion of the CDM savings set out in Table 3-10 for 2016 and 2017 programs attributable to this load displacement generation? If so, why were these "savings" included in the CDM Activity variable when the impact of the load displacement generation is already accounted for by the "cogeneration facility flag"? Please revise the load forecast model to remove the double counting.

iv. If yes, please explain why the 2018 CDM values have not also been adjusted to remove the impact of the load displacement generation?

RESPONSE

The new load displacement generation referenced at Exhibit 3, page 22 (lines 15-17), is not the same facility as discussed in Exhibit 7 (page 10) and for which a "cogeneration facility flag" was included in the Purchased Power Model.

i. This additional load displacement generation is expected to go into service in 2018 and 2019. The “load displacement generation” is included to Energy+’s 2015-2020 CDM Plan.

ii. Not applicable.

iii. Not applicable.

iv. Not applicable.

3-VECC-23

INTERROGATORY

Reference: Exhibit 3, pages 22-23

Exhibit 7, page 10

f) What was the kWh adjustment for load displacement generation that was included in Table 3-20 (per page 22, lines 15-17)? What would be the associated impact on annual billing demand?

RESPONSE

The load displacement generation was excluded in Table 3-20 for 2019. The amount excluded from 2018 programs is 15,270,000 kWh and from 2019 programs is 2,400,000 kWh for a total of 17,670,000 kWh in 2019. This translates into an associated impact on the annual billing demand of 41,470 kW on a full year basis.

3-VECC-24

INTERROGATORY

Reference: Exhibit 3, pages 23-24

a) Please confirm that the LRAMVA values set out in Table 3-24 exclude the savings from the load displacement generation discussed on page 22 (lines 15-17). If not confirmed, please explain why.

RESPONSE

The LRAMVA values set out in Table 3-24 exclude the savings from the load displacement generation discussed on page 22 (lines 15-17).

3-VECC-24

INTERROGATORY

Reference: Exhibit 3, pages 23-24

b) If Energy+ 2018 actual savings from 2018 or 2019 CDM programs include savings due to new load displacement generation in those years (i.e., in addition to the existing 2016 load displacement generation), does Energy+ expect that such savings will be included in the verified results reported by the IESO for those years? If not, why not?

RESPONSE

Energy+ 2018 actual savings from 2018 or 2019 CDM programs include savings due to new load displacement generation in those years. Energy+ does expect that such savings will be included in the verified results reported by the IESO for those years.

3-VECC-24

INTERROGATORY

Reference: Exhibit 3, pages 23-24

c) If yes, why shouldn't these savings also be included in the LRAMVA threshold values for the relevant year(s)?

RESPONSE

Aside from the half year rule adjustment on the manual CDM adjustment, it is assumed the 2019 LRAMVA threshold should be consistent with the 2019 manual CDM adjustment made to the load forecast. It is also assumed that the IESO verified results would be adjusted by Energy+ for load displacement savings before the comparison to the threshold is made in the LRAMVA claim.

3-VECC-24

INTERROGATORY

Reference: Exhibit 3, pages 23-24

d) If yes, what are the expected annual kWh savings and associated impact on annual billing demand?

RESPONSE

The expected annual kWh savings in 2019 is 17,670,000 kWh and associated impact on annual billing demand is 41,470 kW.

3-VECC-24

INTERROGATORY

Reference: Exhibit 3, pages 23-24

e) Please confirm that the energy forecast by customer class excludes: i) the customer load supplied by load displacement generation and ii) the energy use by WMPs. If either point is not confirmed, please explain (with reference to the Load Forecast model) how the relevant energy values have been included in the customer class values.

RESPONSE

The energy forecast by customer class shown in Exhibit 3, Table 3-3 excludes: i) the customer load supplied by load displacement generation discussed in Exhibit 7 (page 10) and ii) the energy used by WMPs.

3-VECC-25

INTERROGATORY

Reference: Exhibit 3, pages 25-27

Load Forecast Model, Rate Class Load Model Tab

a) Does the kW forecast in Table 3-30 include the kW that will be subject to the proposed Standby Charge? If yes, please indicate the values included for each customer class for 2019 and how they were determined.

b) With reference to the Rate Class Load Model Tab, please explain the reason for the 50,379.33 kW adjustment to the 2019 Large Use billing demand forecast. How was the 50,379.33 kW value determined?

RESPONSE

a) The kW forecast in Table 3-30 includes the kW that will be subject to the proposed Standby Charge. The value 50,379.33 kW is included in the Large Use class for 2019. This value is determined by the annual kW difference between one case which assumes a flat contract capacity amount of 28.8 MW per month and another case reflecting the actual monthly load peaks for the load displacement customer in 2016. The adjustment reflects the impact on annual demand units resulting from providing the standby service. In the revised load forecast provided in response to 3- VECC-19 a) the load associated with load displacement customer has been updated for 2017 actual data. This updates the kW that will be subject to the proposed Standby Charge to 30,443.08 kW.

b) See response to a)

3-VECC-26

INTERROGATORY

Reference: Exhibit 3, page 42 (Table3-45)

a) Please provide the 2017 actual Other Operating Revenue broken down per Table-3-45.

RESPONSE

Please refer to Response to Interrogatory 1-Staff-10 a) for updates for 2017 Actuals. Other Operating Revenue for 2017 Actual is included in Chapter 2 Appendices 2H, which is consistent with Table 3-45.

3-VECC-27

INTERROGATORY

Reference: Exhibit 3, pages 42-43 (Table3-45) and 53

Exhibit 8, page 21

a) Please explain the reduction in revenues as between 2016 actual and 2019 forecast for: i) Late Payment Charges, ii) Change of Occupancy Charges, and iii) Document Charges.

RESPONSE

The following are explanations for the changes in revenues as between 2016 actual and 2019 forecast for each of the following:

i) Late payment charges in 2016 were $225,148 compared to the 2019 Test Year of $189,000. Late payment charges in 2017 Actual were $170,944. The reduction in late payment charges is principally attributable to lower average outstanding account balances that attract late payment charges due to: (i) transition to monthly billing; and (ii) reduction in commodity costs due to the introduction of the Fair Hydro Plan.

ii) Change of occupancy charges in 2016 were $277,455 compared to the 2019 Test Year of $238,000. 2016 and 2017 were strong years for the real estate market. Based upon a high level review of housing sales in the community and the estimated number of new subdivisions planned, Energy+ reduced the 2019 Test Year change of occupancy charges by approximately 15%.

iii) Document charges were $411,071 in 2016 and $379,113 in 2017. The 2019 Test Year forecast is $278,000. Actuals to June 30, 2018 are $87,540, as per Response to Interrogatory 3-SEC-28. The reduction in document charges is related to the fact that on November 2nd, 2017 the OEB issued a Decision and Order banning licensed electricity distributors from disconnecting or threatening to disconnect homes for non-payment from November 15th to April 30th every year, and requires that homes that were disconnected due to non-payment be reconnected without charge. With the OEB's announcement on November 2nd, there will not be any revenue earned from document charges (disconnection notices) during the period November 15 to April 30 each year.

3-VECC-27

INTERROGATORY

Reference: Exhibit 3, pages 42-43 (Table3-45) and 53

Exhibit 8, page 21

b) Please explain the significant drop after 2015 in revenues from Collection/Reconnection charges.

RESPONSE

The Collection//Reconnection Charges were $121,631 in 2015, $31,265 in 2016 and $46,667 in 2017. The decrease in revenues from Collection/Reconnection Charges is principally due to the fact that on November 2nd, 2017 the OEB issued a Decision and Order banning licensed electricity distributors from disconnecting or threatening to disconnect homes for non-payment from November 15th to April 30th every year, and requires that homes that were disconnected due to non-payment be reconnected without charge. As a result of this Decision Energy+ is no longer permitted to ask residential customers to pay account collection fees during the disconnection ban. As such, there has been an actual decrease in the Collection/Reconnection Charges. Energy+ expects this to continue in the 2019 Test Year.

<u>3-VECC-27</u>

<u>INTERROGATORY</u>

<u>Reference: Exhibit 3, pages 42-43 (Table3-45) and 53</u>

<u>Exhibit 8, page 21</u>

c) At Exhibit 3, page 53 the Application states that the Specific Charge for Access Power Poles has been increased and the increase ($22.35 to $43.63) is shown in Exhibit 8. However, there is not a similar increase in Pole Rental revenues for 2019. Please reconcile.

<u>RESPONSE</u>

Energy+ has updated the 2019 Test Year pole rental revenue, please refer to 3-Staff-56 a).

EXHIBIT 4 – OM&A

4-VECC-28

INTERROGATORY

Reference: E1/pg. 47

a) E+ variously describes the incremental costs of monthly billing and OEB costs in 2019 as 496k (Figure 1, pg. 47) or 487k (390+97 table 1-18, pg. 49). Please clarify.

RESPONSE

The incremental costs of monthly billing and OEB costs in 2019 is $487k ($390+97 Table 1-18, Pg. 49). The description in Figure 1, Pg. 47 was incorrect.

4-VECC-29

INTERROGATORY

Reference: E1/pg. 50

a) Please explain why the average increase for management/executive salaries for the 2014-2019 period (23%) far exceeds the rate of inflation for the same period.

RESPONSE

The average percentage increase for management/executive salaries that is referred to in this question was computed by VECC as the % increase of the average Management salary in the 2019 Test Year ($138,752 = $3,746,319/27 FTEs) compared to the average Management salary in the 2014 Board Approved Proxy ($112,492 = $3,487,244/31 FTEs).

Based upon this computation, the average wage per FTE of $138,752 in the 2019 Test Year is 23% higher than $112,492. This comparison and computation assumes that the mix of level of employees is constant across the five year period.

As described in Exhibit 4, Section 4.4.1 Compensation Philosophy, Energy+'s total compensation program is reviewed and analyzed for its competitiveness against three market comparators:

- Broader Public Sector Ontario – excluding GTA
- Industrial Sector (Industrial) Ontario – excluding GTA
- LDC Sector – LDCs of similar size and scope, and those that Energy+ considers its market competition for talent.

In setting its total compensation, Energy+ strives to maintain a 50th percentile position against the public and private sectors, with a primary focus on maintaining a 50th percentile position against its LDC market competition.

Energy+ uses a pay grade system that includes 11 pay grades within the management group, with each pay grade having a higher base salary as the level of responsibility increases.

In Exhibit 4, Energy+ provided the Annual Salary Adjustment for Management/Non-Union Staff as follows:

Table 4-18: Annual Salary Adjustment for Management/Non-Union Staff

Annual Salary Adjustment %	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge
Management/Non-Union						
Energy+	NA	NA	3.04%	1.91%	2.00%	2.00%
Former CND	3.39%	2.02%				
Former BCP	0.00%	3.95%				

The average annual % increase for Management/Non-Union Staff Wages from 2014 to 2017 Actual was between 2.23% and 2.59% (former BCP/Energy+ 0%+3.95%+3.04%+1.91% over 4 years and former CND/Energy+ 3.39%+2.02%+3.04%+1.91% over 4 years). The estimated annual increase for the 2018 Bridge and 2019 Test Years is 2%.

Energy+ recognizes that the average annual % increase for Management/Non-Union Staff wages from 2014 to 2017 were higher than inflation.

The increase in 2014 for the former CND employees of 3.39% was principally attributable to the phase in over a two year period of market based adjustments that were identified as part of a third party market survey conducted in 2013. Based upon the market survey at that time, approximately 7 of the 15 pay grades were not within “market” and certain positions were not aligned to the market comparators. As a result, the salaries of certain positions were adjusted over a two year period to align to the target compensation ratio for those positions.

The increase in 2015 for the former BCP employees of 3.95% was principally attributable to the alignment of the management wages to be consistent with the pay grades established for the former CND. Energy+ would also note that the former BCP employees did not receive any increase in 2014 and as such the increase of 3.95% is over a two year period.

The percentage increase in 2016 for Energy+ was based on (i) market based survey information; and (ii) increases in individual salaries based on Energy+’s performance management program, as described under Salaries (Pg. 51 of 540, Exhibit 4).

4-VECC-29

INTERROGATORY

Reference: E1/pg. 50

b) Please explain why management/executive total compensation for that same period also significantly exceeds the non-management increase of the 5 year period (i.e. 21.1% vs 9.8%).

RESPONSE

Energy+ has computed the average percentage increase for non-management as 14.6% using the same methodology used by VECC in 4-VECC-20(a), which is different than the 9.8% quoted above.

Average non-management salary 2014 Board Approved Proxy $70,666 ($7,985,237/113 FTEs) compares to the Average non-union salary 2019 Test Year $80,966 ($8,339,516/103 FTEs).

This comparison and computation assumes that the mix of level of employees is constant across the five year period.

Non-Management salaries comprise both unionized and non-unionized employees; the majority of which are unionized staff. The percentage increases for the unionized staff on an annual basis are derived from a collective bargaining process, based on negotiated processes, whereby wage increases are based on factors such as recent settlements reached in the LDC sector, particularly neighbouring LDCs, as well as the local cost of living factor (as outlined in Exhibit 4, Section 4.4.1.2 Unionized Employees).

Non-management employee wages are set as described for the Management/Executive Salaries. Please refer to a).

4-VECC-30

INTERROGATORY

Reference: E1/pg. 141

a) Please explain how (if) the desired outcomes of the metrics listed in Table 1-10A are related to executive and other employee compensation.

RESPONSE

Energy+ notes that Table 1-10A should have been labelled Table 1-40A.

The measures outlined in Table 1-40A represent a combination of the various measurements that Energy+ has utilized for a number of years, as well as new measures that it will measure, monitor, and report on progress over the next five years. Many of the existing measurements are incorporated into the day to day activities of Energy+ and included in: (i) the corporate Balanced Scorecard; (ii) Key Performance Indicator Report to the Board; (iii) RRR reporting to the OEB; (iv) OEB Scorecard; and (v) various other forms of reporting to the Board of Directors.

As outlined in Exhibit 4, Employee Compensation, Energy+'s performance management program provides a system for rewarding employees based on behavior and performance competencies; the various performance measures in place assist in assessing employee performance and determining merit increases for non-management and management employees.

The Corporate Balanced Scorecard is used as a tool to measure Energy+'s performance aligned to its Strategic Imperatives. The Corporate Balanced Scorecard is also used as part of the executive and management incentive program as described in Exhibit 4, Section 4.4.1.Compensation Philosophy, 4.4.1.3 Incentive.

With respect to the Performance Measures outlined in Table 1-40A, the following metrics have historically and/or are currently incorporated into Energy+'s Corporate Balanced Scorecard:

- Service quality metrics
    - Connection of New Services within 5 Business Days
    - Appointments Met
    - Customer Access/Calls Answered
    - Locate Service Performance
- System reliability
    - SAIDI, SAIFI, CAIDI

Please refer to Response to Interrogatories 1-SEC-6(a) for the historical Corporate Balanced Scorecards.

4-VECC-31

INTERROGATORY

Reference: E1/pg. 146

a) Please update E+'s Scorecard to include 2017 actual results.

RESPONSE

Please see the response to interrogatory 1-Staff-10c) for the Energy+ Scorecard updated with 2017 actual results.

4-VECC-31

INTERROGATORY

Reference: E1/pg. 146

b) Why in the provided Scorecard was E+ forecasting a significant decline in its future reliability performance?

RESPONSE

Reliability performance (both SAIDI and SAFI) declined in 2017 vs 2016 actual due to the following factors:

- An outage in the CND area occurred on the 65M15 feeder along Franklin Boulevard20 where there were four (4) lockouts during rain and wind conditions. Work has been done along Franklin Boulevard to install spacers between phases and dampers to try and reduce outages along this exposed section of multi-circuit 27.6kV lines.

- There were two (2) broken porcelain insulators that significantly affected the number of customer hours of interruption in 2017. Energy+ is increasing its change-out rate of these insulators in 2018 and beyond to further address this issue.

- A large outage in the Brant area due to a complete dc power failure at Powerline MTS that resulted in both 115-26 kV circuits being forced from service. Several changes were made immediately after the incident; however, further changes will be made to reduce the likelihood of a similar event in the future.

These outages are described in Section 2.3.1.1.2 of the DSP.

4-VECC-32

INTERROGATORY

Reference: E1/pg. 249 & Appendix 2-K

a) Please explain why in the 2018-19 Business Plan it lists salaries and benefits expenditures of $10.6M whereas in Appendix 2-K the amount listed is $15.3 (rounded).

RESPONSE

The salaries and benefits expenditures of $10.6MM for 2018 OM&A included in the 2018 Operating Expenditure budget represents the value of expenditures allocated to Operating expenditures. The difference between this amount and the amount of $15.3MM (rounded) in Appendix 2-K would be the estimated amount of salaries and benefits that are either capitalized, billable to third parties, or included in removal costs (incorporated as part of depreciation expense).

4-VECC-33

INTERROGATORY

Reference: Exhibit 4, pg.29

a) Please explain how the incremental customer care clerk and billing clerk are directly associated with the move to monthly billing.

RESPONSE

All customers served by Energy+ were transitioned to monthly billing as of January 2, 2017. Customers served by the former Brant County Power Inc. were already being monthly billed at the time of the amalgamation on January 1, 2016. Commercial and Industrial customers served by the former Cambridge and North Dumfries Hydro Inc. were also already being billed monthly. The residential and small commercial customers of the former Cambridge and North Dumfries Hydro Inc. were the customers that were transitioned to monthly billing commencing in November 2016 and December 2016. For Energy+, moving all customers to monthly billing meant an increase of over 300,000 additional bills being issued annually. To illustrate the increase in bills issued, the average number of residential and small commercial bills issued to Cambridge and North Dumfries customers before monthly billing was 26,057 bills per month and this doubled to 52,346 bills per month, a 100% increase in residential and small commercial bills.

A Customer Care Clerk is responsible for processing all payments, including Cheque payments through the mail, Electronic Funds Transfer, Debit Card, and Preauthorized Payments. The Clerk is responsible to send telephone reminder calls for Residential Accounts, printing of reminder notices for small commercial accounts, and to run/print door hangers for Collections. With the move to monthly billing, these activities moved from a two (2) month billing and collection cycle to a compressed one (1) month billing and collection cycle.

Similarly, in Billing, the additional resource, a Billing Representative I, was added to address the increased volume and workload of billing all customer cycles daily, over a one-month period, instead of a two-month period. The billing functions and processes to issue a bill did not change with the move to monthly billing, only the volume of output increased requiring an additional resource to ensure accurate and timely monthly bills are issued to customers.

4-VECC-33

INTERROGATORY

Reference: Exhibit 4, pg.29

b) Please explain how monthly billing causes “incremental collection notices” and how “processing of increased payments” is related to the move to monthly billing.

RESPONSE

Exhibit 4, Table 4-11 outlines an additional $25,000 in Other Expenses as a result of the increase in volume of bills issued monthly, which also resulted in additional collection activity.

Other expenses include the incremental costs associated with an increase in the printing of collection notices, and the costs for third party telephone minutes for Friendly Reminder calls. Sub-contractor delivery costs increased based on the increased volume of collection notices.

Despite the reduced amounts being billed to customers with monthly bills, some customers unable to pay their bi-monthly bill by the due date, continued to experience problems paying their monthly bill, by the due date. For example, in the first six months of 2017, Energy+ saw an 8% increase in residential Friendly Reminder calls and a 54% increase in residential collection notices. Monthly billing also increased the volume of customer payment transactions received, triggering an increase in banking fees paid to process electronic payments made by customers.

4-VECC-34

INTERROGATORY

Reference: Exhibit 4, pg.30

a) What incentives does Energy+ offer its customers to switch to e-billing or if they pay through on-line banking?

RESPONSE

As part of the augmented customer engagement surveys, Energy+ polled customers on the likelihood they would switch to e-billing. Between 48%-52% of low-volume customers in the County of Brant responded they are unlikely to switch to e-billing knowing they would receive a $0.75 credit on each bill. Cambridge and North Dumfries customers (32%-35%) responded they were unlikely to switch to e-billing knowing they would receive a $0.75 credit on each bill (Exhibit 1, Page 397). Further, some 18% of customers stated they had not signed up for e-billing because they were not aware it was available. Based on these results, Energy+ is focusing on lower cost incentives, as outlined below, to attract increased customer e-billing uptake and increasing the promotion of e-billing to increase customer awareness.

Energy+ runs promotions with financial incentives to encourage its customers to switch to eBilling, and remain enrolled. For example, existing paperless billing customers and customers who newly enroll in e-billing between September 1 and December 31, 2018, will have two chances every month (September to December), to win a $250 pre-paid credit card. A similar campaign was implemented in 2017, with positive results in new e-billing sign ups.

Energy+ does not offer incentives to pay through on-line banking. Approximately, 93% of customers pay their bill electronically.

4-VECC-35

INTERROGATORY

Reference: Exhibit 4, pg.32

a) We are unclear how as to why and how there is an increase in operating cost with the potential sharing of services with Brantford Power (BPI). The evidence states:

The increase in operating costs of $195,000 is comprised of the following:

	Annual Cost
Shared Space Operating Lease Estimate	$255,000
Shared Mechanic (1/2 FTE)	40,000
Operating Costs (Exclusive Space)	35,000
	$330,000
Less: Current Operating Costs (Existing Facility)	(135,000)
Total Operating Costs	$195,000

i) Why does the sharing of the mechanic with BPI who is employed by Energy+ result in an increase in cost?

ii) Why is Energy+ leasing space for $255k to replace space that cost 135k?

RESPONSE

i) The Shared Mechanic position would be a new FTE position shared 50/50 between Energy+ and BPI. Currently, Energy+ has one mechanic located in the CND service territory that principally services the CND service territory vehicles. There is very little capacity remaining for the one mechanic employed by Energy+ to service all of the vehicles in both service territories. Vehicle servicing and repairs for the vehicles that are utilized in the Brant County service territory are substantially completed by third party mechanical service providers. As a result of sharing a mechanics bay, Energy+ and BPI would share an in-house mechanic.

In Response to Interrogatory 4-Staff-61, Energy+ provided the following additional information:

As explained in Exhibit 4, Pg. 31, Energy+ and BPI plan to enter into a Shared Service Agreement to achieve economies of scale, and as well as this collaboration is expected to achieve operating synergies in the future that will benefit customers. Achieving economies of scale and/or operating synergies will not always equate to a reduction of operating costs in a single year. It also means that future costs are avoided, efficiencies can lead to a greater number of activities being achieved with existing resources (preventing future hires), or costs can be spread over a larger customer base resulting in lower unit costs.

Specific areas of economies of scale identified with respect to the shared Mechanics Bay included:

- Sharing space for mechanical/vehicle bays, stock room and outdoor space.

  The sharing of a mechanical bay, stock room, and outdoor space results in a sharing of warehousing and other equipment (e.g. forklifts, tools and equipment used by the mechanic, etc.) as opposed to each utility acquiring its own, as well as reducing the number of future capital replacements.

- Improved service levels to customers and reduce costs to third party mechanical services as a result of an in-house mechanic to provide mechanical services provided to Energy+.

  The implementation of on-site fueling, as well as a mechanical bay to service vehicles, is expected to result in productivity improvements in both operating and capital activities (an increase in tool time for outside crews), including: (i) a reduction in travel time (non-tool time) as a result of fueling on-site; and (ii) vehicles are available sooner as a result of having inspections, maintenance and small repairs completed on-site.

(ii) As explained in Response to Interrogatory 4-Staff-61, the $255,000 in annual operating lease cost for the shared space represents the annual lease cost with respect to:

  - 50% of the estimated capital costs associated with the construction of the shared space ($155,652); plus

- An incremental amount for the annual operating costs (e.g. utility costs, property taxes, repairs, landscaping, cleaning, etc.) of approximately $100,000. The $100,000 plus the $35,000 for the exclusive space compares to the $135,000 in annual operating costs incurred at the existing facility.

As the shared space is being constructed (capital) and then leased from BPI, it is represented as an operating lease to Energy+.

As explained in Exhibit 2, Appendix 2-1 DSP, Appendix N: Facilities Business Plan the existing operations facility in the Brant service territory is 34+ years old and in poor condition. In the past few years repairs were identified as being required to address roof leaks, flooding, and mold in a portion of the building. The facility is also no longer suited to its original functionality since the amalgamation. The administrative portion of the building (approximately 5,000 square feet) is largely unused since these employees were relocated to Cambridge. The operational space, on the other hand, is too small to accommodate increased rebuild activity and anticipated customer growth in the Brant County service territory. Over the next ten years, Energy+ expects an increase in construction activity in the Brant County service territory due to (i) customer growth; and (ii) a renewal program as a result of ageing infrastructure. In order to fully utilize the existing space, the building would need to be substantially renovated and reconfigured, including to increase the space required for operations, vehicles and inventory, which the current building was not designed to house. Building a new facility on this land would incur similar cost per square feet relative to the Garden Ave. (BPI) build.

Therefore, if Energy+ were to renovate or build its own facility in the Brant Service territory, such costs would be included as capital expenditures and subsequently amortize these costs as part of annual amortization expense. The $155,652 is therefore more representative of amortization expense.

4-VECC-36

INTERROGATORY

Reference: Exhibit 4, pgs.32-34, 42

a) What was the forecast annual operating cost of the System Control Room provided to the Board in EB-2013-0116?

RESPONSE

In EB-2013-0116, the former CND estimated the annual operating costs related to the addition of three system control room operators at $180,000 for wages and benefits (EB-2013-0116, Response to Interrogatories 3.1-Staff-6, Pg. 531).

Energy+ would note that, as explained in Exhibit 4, Section 4.4.2.1 Employee Costs and Variance Analysis, the 2014 Board Approved OM&A of the former CND was reduced by $379,806 citing “increase in staffing levels which seems aggressive…”

4-VECC-36

INTERROGATORY

Reference: Exhibit 4, pgs.32-34, 42

b) What are the current forecast annual operating costs for this is 2018?

RESPONSE

The forecast annual operating costs related to the transition to 24/7 Control Room is $175,000 for wages and benefits for three control room operators.

4-VECC-37

INTERROGATORY

Reference: Exhibit 4, pg49

a) Please amend Table 4-17 to add a row showing the annual yearly inflation rate (CPI) for each year 2014 through 2018 (to-date).

RESPONSE

Energy+ has created the following Table 4-VECC-37c), consistent with Table 4-17, to add the annual yearly inflation rate (CPI) for each year 2014 through 2018 (to-date). Energy+ used the Bank of Canada CPI Index, 2000 to Present, Total CPI measure.

Table 4-VECC-37c): Collective Agreement Wage Adjustment

Collective Agreement Annual Wage Adjustments

	Notes	2014	2015	2016	2017	2018	2019
Inside Collective Agreement - IBEW (April 1)		2.30%	2.25%	2.25%	2.20%	2.0%	2.0%
Outside Collective Agreement - IBEW (April 1)		2.30%	2.25%	2.25%	2.20%	2.0%	2.0%
Outside Collective Agreement - PWU (April 1 up to March 31, 2017)	1, 2	2.85%	2.25%	2.25%	NA	NA	NA
						YTD 2018-07	
CPI Increase	3	1.50%	1.60%	1.50%	1.90%	3.00%	

Notes:
(1) April 1, 2015 to March 31, 2017 Agreement also included a one-time $1.50 adjustment for all PLTs and $0.75 for Meter Technicians to phase in to former CND rates.
(2) PWU Agreement expired in March, 2017. IBEW became the sole union effective October 19, 2017, as a result of a representation vote under the Ontario Labour Relations Board.
(3) Source: Bank of Canada CPI Index, 2000 to Present, Total CPI Measure

Agreement Dates
Inside IBEW - April 1, 2014 to March 31, 2018
Inside IBEW - April 1, 2018 to March 31, 2024
Outside IBEW - April 1, 2014 to March 31, 2018
Outside IBEW - April 1, 2018 to March 31, 2024
Outside PWU - April 1, 2012 to March 31, 2015
Outside PWU - April 1, 2015 to March 31, 2017

4-VECC-38

INTERROGATORY

Reference: Exhibit 4, pg. 56, appendix 2-K

a) Please amend Appendix 2-K to add a row showing the total compensation capitalized in each year.

RESPONSE

Please refer to Response to Interrogatory 4-SEC-32.

4-VECC-39

INTERROGATORY

Reference: Exhibit 4, pg. 74

a) Please provide the EDA fees (actual and forecast) on a combined basis for the years 2014 through 2019.

RESPONSE

The following Table 4-VECC-39 provides the EDA fees (actual and forecast) on a combined basis for the years 2014 through 2019:

Table 4-VECC-39: Summary of Annual EDA Fees

Vendor Name	Product/Service	Actuals				Bridge	Test
		2014	2015	2016	2017	2018	2019
Electricity Distributors Association	EDA FEES	**$90,600**	**$77,100**	**$77,900**	**$78,700**	**$80,272**	**$80,272**

4-VECC-40

INTERROGATORY

Reference: Exhibit 4, pg. 82

a) Please provide (separately) the legal costs, consultant costs incurred to date for this application.

RESPONSE

Legal costs incurred to June 30, 2018 were approximately $73,300.

Consultant costs incurred to June 30, 2018 were approximately $344,800.

4-VECC-40

INTERROGATORY

Reference: Exhibit 4, pg. 82

b) Please describe the incremental staff costs of $107,538 allocated to this application. Specifically address what costs were incurred to replace staff resources allocated to this application.

RESPONSE

The incremental staff costs of $107,538 represent temporary/contract staff hired to: (i) ‘back fill’ for full-time accounting staff who were working on the Application; and (ii) to complete certain aspects of the Application to allow staff to complete their regular duties without interruption.

4-VECC-40

INTERROGATORY

Reference: Exhibit 4, pg. 82

c) Please breakdown by consultant the $347,861 in consulting costs incurred on this application. Please show the actual costs incurred to date for each consultant.

RESPONSE

Please see Energy+'s response to interrogatory 4-SEC-34 for a detailed breakdown of the $347,861 of consulting costs.

Table 4-VECC-40c), below shows the actual consultant costs incurred to June 30, 2018.

Table 4-VECC-40 c): Consultant Costs

Actual Consultant Costs - To Date June 30, 2018	
Customer Engagement Strategy and Execution	156,656
Load Forecast, Cost Allocation, Rate Design, Standby Rates	103,037
Distribution System Capital Plan	58,400
Witness Training	-
Conservation Impacts on Load Forecast, LRAM calculations, Other	19,705
Public meeting Expenses	-
Other	7,000
Total	**344,798**

4-VECC-41

INTERROGATORY

Reference: Exhibit 4, page 111 (lines 7-13)

http://www.ieso.ca/en/sector-participants/conservation-delivery-and-tools/conservation-targets-and-results

a) The 2017 Verified CDM Results Reports have been released by the IESO. Please update the LRAMVA Workforms and provide a revised version of Table 4-57.

RESPONSE

Please refer to Responses to Interrogatories 4-Staff-64 and 4-Staff-71 c).

EXHIBIT 5 – COST OF CAPITAL

5-VECC-42

INTERROGATORY

Reference: Exhibit 5, page 6

a) Please recalculate the long-term debt rate on the assumption that the notional portion of the debt attracts the Board's affiliate debt interest rate.

RESPONSE

Energy+ has provided the requested computation in Table 5-VECC-42a) below based on the assumption requested by VECC.

The requested computation recalculates the long-term debt rate on the assumption that the notional portion of the debt attracts the Board's affiliate debt interest rate. This is a variation of Table 5-2: 2019 Deemed Capital Structure.

Table 5-VECC-42a): Notional Debt Included at Board Interest Rate

	(%)	($)	(%)	($)
Debt				
Long-term Debt	51.42%	$88,019,703	4.37%	$3,844,892
Notional Debt	4.58%	$7,847,479	4.16%	$326,455
Short-term Debt	4.00%	$6,847,656	2.29%	$156,811
Total Debt	60.0%	$102,714,838	4.21%	$4,328,158
Equity				
Common Equity	40.00%	$68,476,559	9.00%	$6,162,890
Preferred Shares	0.00%	$ -		$ -
Total Equity	40.0%	$68,476,559	9.00%	$6,162,890
Total	100.0%	$171,191,397	6.13%	$10,491,049

5-VECC-42

INTERROGATORY

Reference: Exhibit 5, page 6

b) Since the $7.8M is notional debt please explain why it would not be appropriate to use either the Board's default affiliate rate or the lowest long-term borrowing rate of the Utility (i.e. 3.97%) to calculate the amount of deemed interest costs to be recovered related to notional debt?

RESPONSE

Energy+ has utilized the weighted average interest rate of actual long-term debt on its notional debt in accordance with the Board's policy on cost of capital, and in accordance with the Filing Requirements. Section 2.5.2 Cost of Capital in the 2019 Filing Requirements specifically states that "…notional debt should attract the weighted average cost of actual long-term debt rather than the current deemed long-term debt rate issued by the OEB. This approach has been upheld in several decisions in recent years."[1]

Energy+'s proposal in this Application is also consistent with the approach approved for the former CND in its 2014 Cost of Service Application.[2]

[1] Filing Requirements for Electricity Distribution Rate Applications, 2018 Edition for 2019 Rate Applications, July 12, 2018, Pg. 41

[2] EB-2013-0116 Cambridge and North Dumfries Hydro Inc. Decision and Order, August 14, 2014, Pg. 8-9.

5-VECC-43

INTERROGATORY

Reference: Exhibit 5, page 7

a) If the net result of Energy+'s loan of $3,665,000 with its affiliate is zero because an equal amount of interest is earned as is paid on this debt what purpose does this borrowing serve and what benefit does Energy+ receive on this transaction?

RESPONSE

As explained on Pg. 7, the intercompany debt of $3,665,000 represents cash that was advanced to Energy+, which is combined with Energy+'s cash. By combining cash balances of the corporate group of companies, a higher interest rate is earned than may be possible if each company invested independently.

Under its current banking arrangement, if Energy+ has a cash balance of between $0 and $4,999,999, Energy+ earns interest on its bank balances of Prime minus 1.85%; when cash balances are in excess of $5,000,000, Energy+ earns interest at a rate of Prime minus 1.75%. Therefore, the advance of $3,665,000 has the benefit of increasing the overall cash balance for Energy+ and its group of companies, which results in a higher interest income for Energy+ Inc. on its cash balances. As interest income is a revenue offset, customers benefit from higher earned interest income.

Example:				Annual Interest Income	
				Based on Pooled Cash Balances @ 1.95%	Based on Individual Cash Balances @ 1.85%
Energy+ Cash Balance	$	2,000,000		$ 39,000	$ 37,000
CND Energy Plus Advance	$	3,665,000			
Total Cash Balance for Interest	$	5,665,000			
Current Prime Rate		3.70%			
			Interest Rate		
Interest Rate if Cash Balance < $5MM	Prime - 1.85%		1.8500%		
Interest Rate if Cash Balance > $5MM	Prime - 1.75%		1.9500%		

EXHIBIT 7 – COST ALLOCATION

7-VECC-44

INTERROGATORY

Reference: Exhibit 7, page 6

a) Were there no assets associated with Services recorded for the CND service area because: i) all customers pay for their service connections or ii) the costs incurred by CND were recorded in another account?

RESPONSE

Energy+ recorded Services for the CND service area in other accounts, consistent with the accounts utilized in its 2014 Cost of Service Application. Please refer to Response to Interrogatory 7-Staff-79.

7-VECC-44

INTERROGATORY

Reference: Exhibit 7, page 6

b) Why are only Residential, GS<50, GS 50-999 and GS 1000-4999 given weighting factors for Services?

RESPONSE

The net book value of account 1855 - Services is $1.1 million which is a relatively small amount of assets compared to the total net book value for Energy+. These assets are associated with the BCP service area. Since the amount was small it was assumed it would be allocated to the main classes (i.e. Residential, GS<50, GS 50-999 and GS 1000-4999) that had customers in them from the BCP service area.

7-VECC-44

INTERROGATORY

Reference: Exhibit 7, page 6

c) What were the Service weighting factors used by BCP in its last cost of service application? Would it not be more appropriate to use these?

RESPONSE

The service weighting factors used by the former BCP in its last Cost of Service Rate Application were the default values used in the original cost allocation model. It is not appropriate to use these factors since the OEB expects distributors to develop and justify their own weighting factors. Energy+ does not have the information to determine the cost of installing service assets in the BCP service area by rate class. As a result, Energy+ submits that it is appropriate to allocate account 1855 based on non-weighted customer numbers. As the amount is small, any adjustment to the service weighting factors would have a very minimal impact on the costs allocated to the various rate classes.

7-VECC-44

INTERROGATORY

Reference: Exhibit 7, page 6

d) Do any of Energy+ Residential or GS customers have more than one service connection? If yes, how many customers and what are the number of associated service connections?

RESPONSE

Yes, Energy+ has seven (7) GS customers and one (1) Large Use customer with more than one service connection. These are situations where Energy+ provides two 27.6kV services to each customer and the metered quantities from the two services are totalized into one customer bill. This does not include situations where a customer has two services to one property but receives two bills. There are GS and Residential services where this is the case.

7-VECC-45

INTERROGATORY

Reference: Exhibit 7, page 6

a) What was the basis for the Billing and Collecting weighting factors used in the former CND's 2014 cost of service application (e.g., were they based on an analysis of CND's billing and collecting activities)?

RESPONSE

In the former CND's 2014 Cost of Service Rate Application, CND determined the weighting factor to be used for each customer class by totaling the costs for Billing and Collecting and allocating costs associated with a typical bill for each customer class. A weighting factor was determined by assigning the Residential customer class a factor of 1, and determining the relative weights of the rest of the classes. The weighting factors were based on an analysis of CND's billing and collecting activities.

7-VECC-46

INTERROGATORY

Reference: Exhibit 7, page 7 / Cost Allocation Model, Tab I7.1 – Meter Capital

a) Please explain why there is no meter/meter capital attributed to the Embedded Distributor-Waterloo North Hydro.

RESPONSE

There is no meter/meter capital attributed to the Embedded Distributor-Waterloo North Hydro because Waterloo North Hydro owns their own 27.6 KV primary metering unit.

7-VECC-47

INTERROGATORY

Reference: Exhibit 7, pages 8-9 / Appendix 2-Q

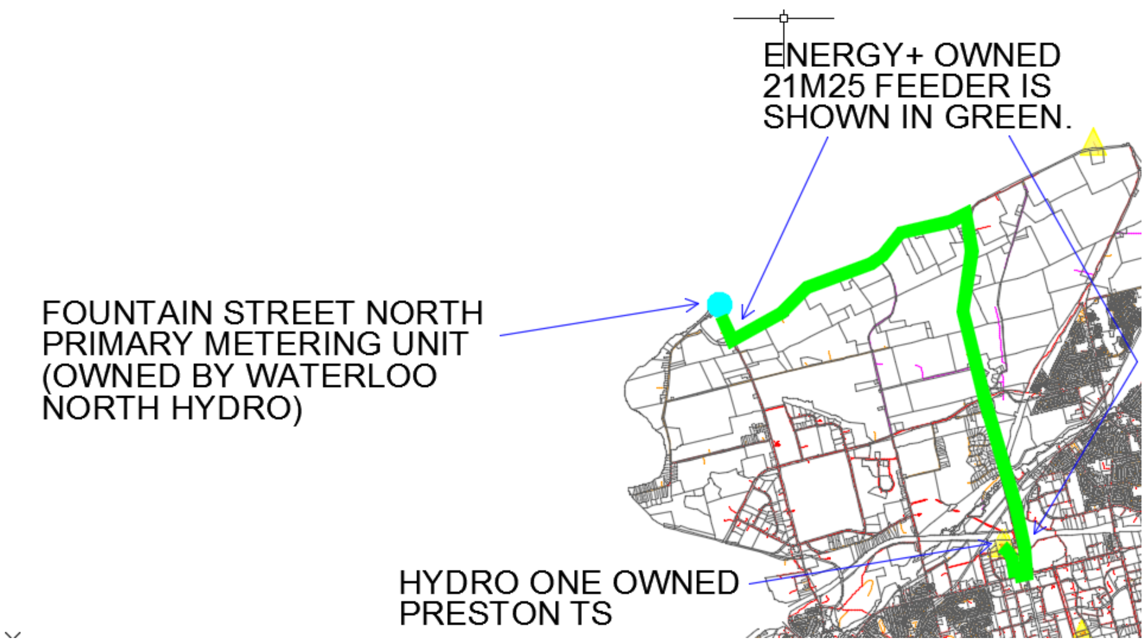
a) For each of the Embedded Distributor customer classes, please describe the supply arrangements in terms of what facilities owned by Energy+ are used to supply the customer(s) and how these facilities connect to HONI's transmission system.

RESPONSE

The supply arrangements in terms of what facilities owned by Energy+ are used to supply the customer(s) and how these facilities connect to HONI's transmission system for each of the Embedded Distributor customer classes, is described below.

Waterloo North Hydro – Fountain Street North at Riverbank Drive (Cambridge)

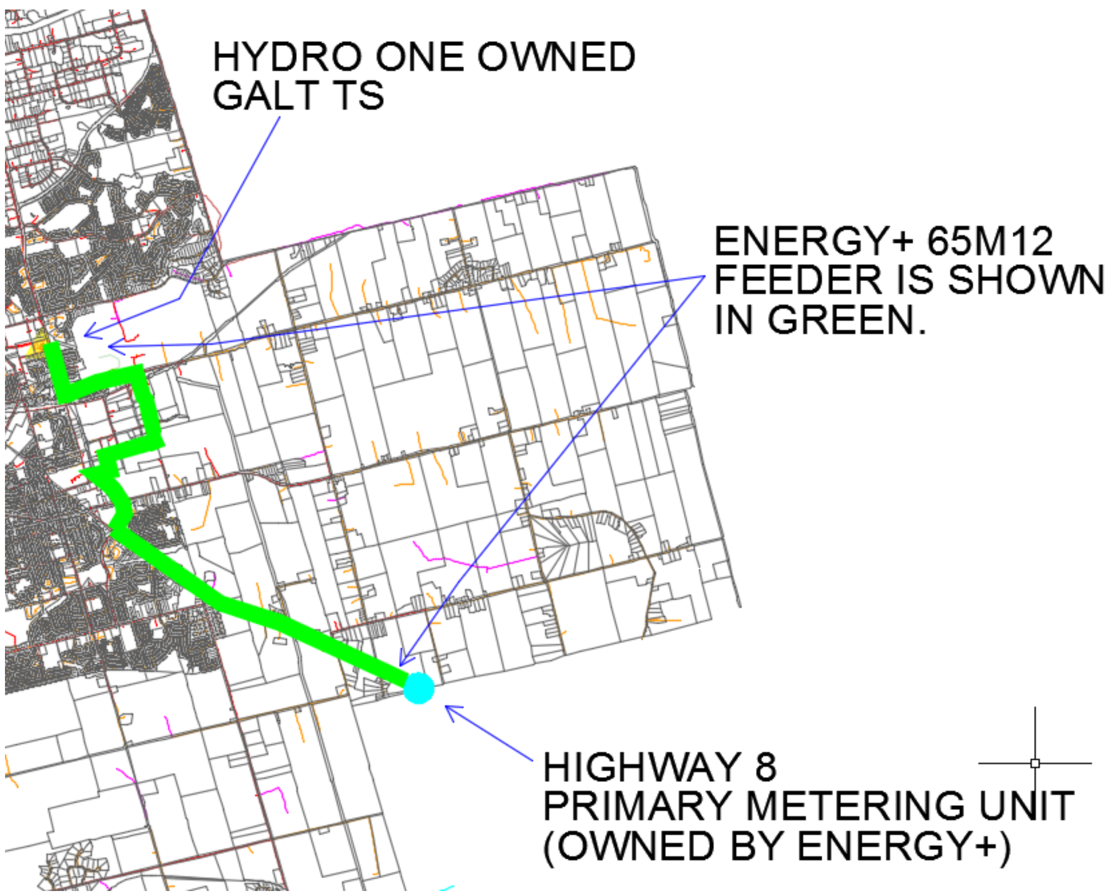
Energy+ provides a three phase 27.6kV supply to Waterloo North Hydro on Fountain Street North at Riverbank Drive in Cambridge where the Energy+ service area meets the Waterloo North Hydro service area. Please refer to the map below for the location.



The source of the power is normally from the Energy+ owned three phase 27.6kV 21M25 feeder from the Hydro One Networks owned Preston TS. The 21M25 feeder supplies Energy+ customers between Preston TS and Fountain Street North. A primary metering unit at Fountain Street North and Riverbank Drive then measures the power consumed by Waterloo North Hydro. From the metering unit, the Waterloo North Hydro portion of the 21M25 feeder goes north into Waterloo North Hydro's service area. The power at Preston TS is measured by Energy+ owned 230kV metering. The primary metering unit on Fountain Street North at Riverbank Drive is owned by Waterloo North Hydro.

Hydro One Networks Inc. (CND Service Territory)

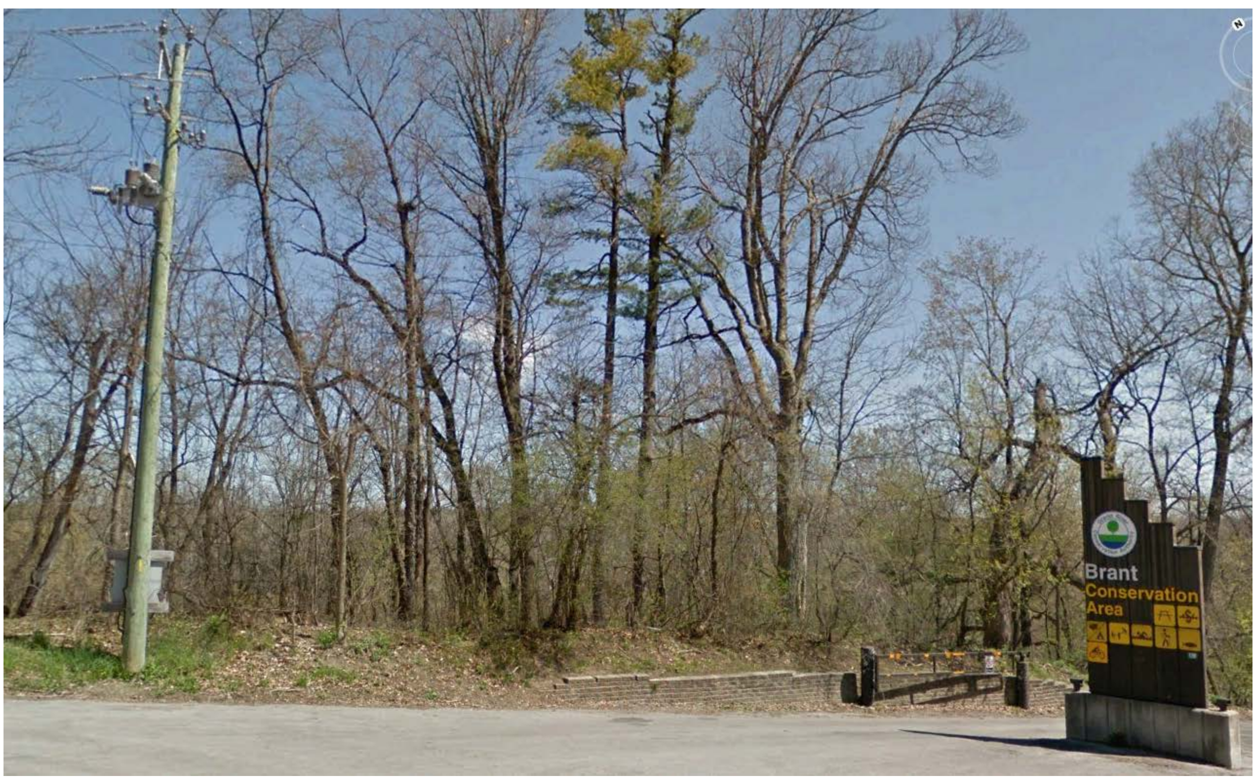
Energy+ provides a three phase 27.6kV supply to Hydro One Networks on Highway 8 at the boundary between the Township of North Dumfries and the City of Hamilton where the Energy+ service area meets the Hydro One Networks service area. Please refer to the map below for the location.



The source of the power is normally from the Energy+ owned three phase 27.6kV 65M12 feeder from the Hydro One Networks owned Galt TS. The 65M12 feeder supplies Energy+ customers between Galt TS and the boundary between the Township of North Dumfries and the City of Hamilton on Highway 8. A primary metering unit on Highway 8 at the boundary then measures the power consumed by Hydro One Networks. From the metering unit, the Hydro One Networks portion of the 65M12 feeder goes South into Hydro One Networks service area. The power at Galt TS is measured by Energy+ owned 230kV metering. The primary metering unit on Highway 8 is owned by Energy+.

Brantford Power Inc.

Energy+ provides a three phase 8.32kV supply to Brantford Power at 119 Jennings Road (Brant Conservation Area). Please refer to the image below for the location.

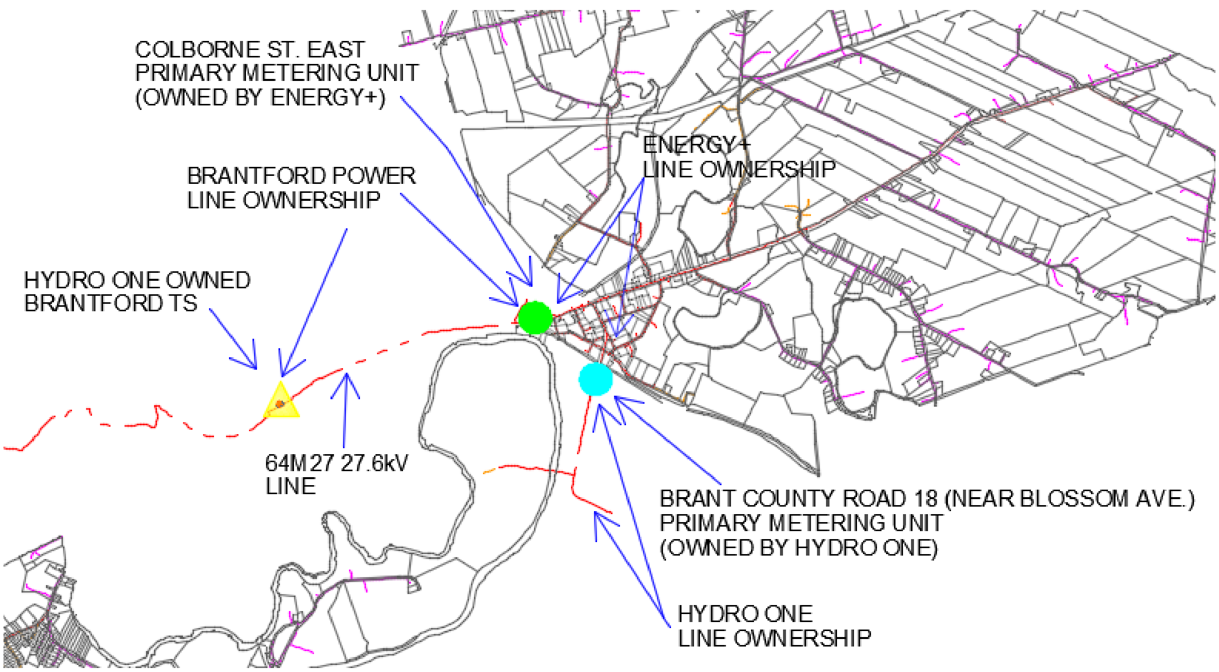


The source of the power is normally through an Energy+ owned three phase bank of 27.6/16kV-8.32kV stepdown transformers located on Greens Road South of Robinson Road that feeds an Energy+ owned 8.32kV overhead line going East on Robinson Road to Jennings Road which also supplies other Energy+ customers. The upstream 27.6kV supply to the stepdown transformers is normally the Brant TS 12M11 27.6kV feeder. Brant TS is owned by Hydro One Networks. Energy+ owns the 12M11 27.6kV feeder.

At 119 Jennings Road, Energy+ owns a 50' Class 4 wood pole that was installed in 2012. Energy+ also owns the 8.32kV primary metering unit.

Hydro One Networks Inc. # 1 (Brant Service Territory) - Brant County Road 18 (near Blossom Avenue)

Energy+ provides a three phase 27.6kV supply to Hydro One Networks on Brant County Road 18 (near Blossom Avenue) where the Energy+ service area meets the Hydro One service area. Please refer to the map below for the location.



The source of the power is normally from an Energy+ owned three phase 27.6kV line on the Hydro One Networks owned Brantford TS 64M27 feeder. Brantford Power owns the 64M27 feeder from Brantford TS to the service area boundary with Energy+. At the service area boundary between Brantford Power and Energy+ on Colborne Street East, there is an Energy+ owned 27.6kV primary metering unit to measure the power withdrawn from Brantford Power's distribution system Energy+ owns the 27.6kV line and supplies its customers within its service area on the East side of the City of Brantford (known as Cainsville). The 27.6kV line then continues into the service area of Hydro One Networks. At the service area boundary between Energy+ and Hydro One Networks on County Road 18 (near Blossom Avenue), there is a Hydro One Networks owned 27.6kV primary metering unit which measures the power consumed by Hydro One Networks.

Hydro One Networks Inc. # 2 (Brant Service Territory) – *Brian Drive, Burford, King Street, Burford, Pleasant Ridge Road, King Edward Street, Paris*

Brian Drive

A Hydro One Networks owned three phase 27.6kV primary metering unit is located on Brian Drive in the community of Burford where the Energy+ service area meets up with Hydro One Networks. Hydro One Networks owns the main line 27.6kV 12M21 feeder from Brant TS to Brian Drive in the community of Burford and beyond. The metering unit is required since the 12M21 feeder also supplies Energy+ load between Brant TS and Brian Drive.

The source of the power is normally from a Hydro One Networks owned three phase 27.6kV line supplied from the Hydro One Networks owned Brant TS 12M21 feeder. Hydro One Networks owns the main line 12M21 feeder between Brant TS and Brian Drive in Burford. The Hydro One Networks owned feeder supplies Energy+ customers as it is running through the Energy+ service area. A primary metering unit at Brant TS measures the power at the start point of the 12M21 feeder. Primary metering units on Brian Drive in Burford, on King St. in Burford (at Burford DS) and on Pleasant Ridge Road measure the outflow of power to Hydro One Networks. The difference is the consumption by Energy+. The primary metering unit on Brian Drive is owned by Hydro One Networks.

King Street

A Hydro One Networks owned three phase 8.32kV primary metering unit is located on King Street in the community of Burford at Hydro One Networks owned Burford DS. Hydro One Networks owns the main line 27.6kV 12M21 feeder from Brant TS to the community of Burford and beyond. The metering unit is required since the 12M21 feeder also supplies Energy+ load between Brant TS and Brian Drive. The primary metering unit is located on the 8.32kV Burford

DS F2 feeder. There is no load on the Burford DS F1 feeder. Hydro One considers anything metered at less than 13.8kV to be secondary metered.

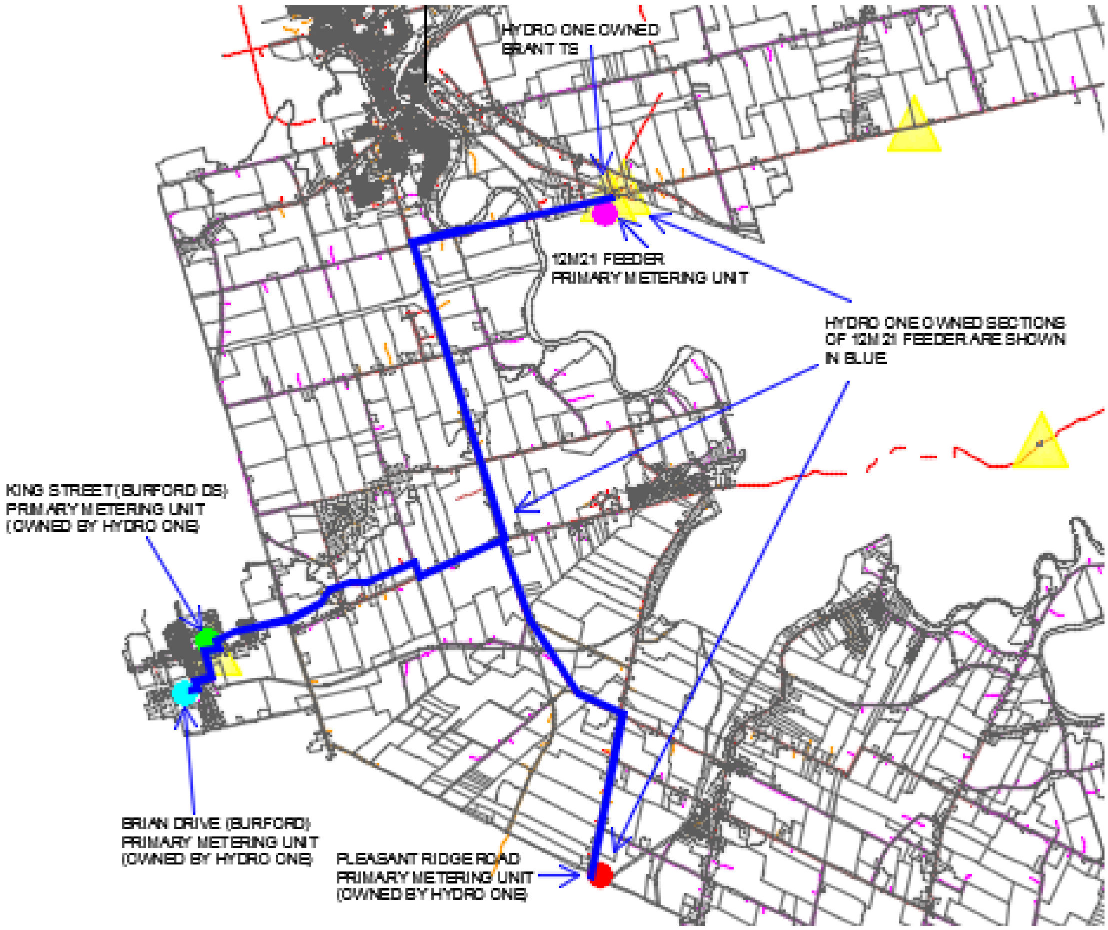
The source of the power is normally from a Hydro One Networks owned three phase 27.6kV line supplied from the Hydro One Networks owned Brant TS 12M21 feeder. Hydro One Networks owns the main line 12M21 feeder between Brant TS and King Street (Burford DS) in the community of Burford. The Hydro One Networks owned feeder supplies Energy+ customers as it is running through the Energy+ service area. A primary metering unit at Brant TS measures the power at the start point of the 12M21 feeder. Primary metering units on Brian Drive in Burford, on King St. in Burford (on 8.32kV Burford F2 feeder at Burford DS) and on Pleasant Ridge Road measure the outflow of power to Hydro One Networks. The difference is the consumption by Energy+. The primary metering unit on King Street (Burford DS) is owned by Hydro One Networks. Other than Burford DS, all other primary metering units are 27.6kV.

Pleasant Ridge Road

A Hydro One Networks owned three phase 27.6kV primary metering unit is located on Pleasant Ridge Road where the Energy+ service area meets the Hydro One Networks service area. Hydro One Networks owns the main line 27.6kV 12M21 feeder from Brant TS to the primary metering unit location on Pleasant Ridge Road. The metering unit is required since the 12M21 feeder also supplies Energy+ load between Brant TS and Pleasant Ridge Road.

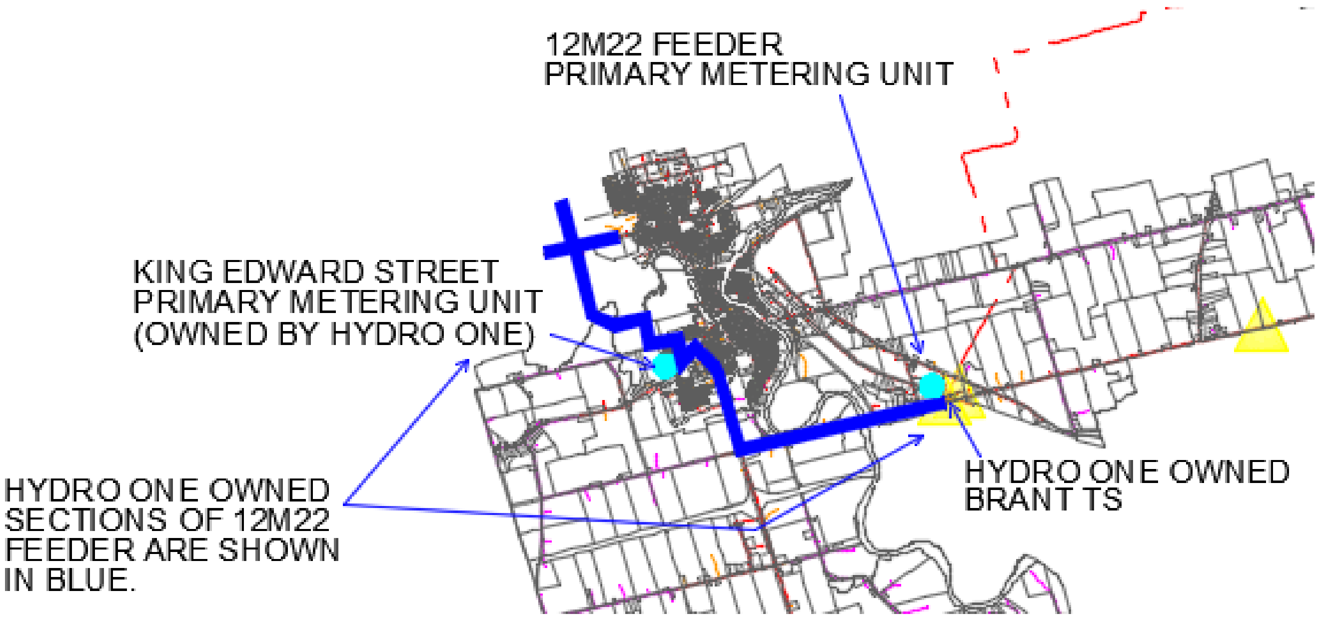
The source of the power is normally from a Hydro One Networks owned three phase 27.6kV line supplied from the Hydro One Networks owned Brant TS 12M21 feeder. Hydro One Networks owns the main line 12M21 feeder between Brant TS and Pleasant Ridge Road. The Hydro One Networks owned feeder supplies Energy+ customers as it is running through the Energy+ service area. A primary metering unit at Brant TS measures the power at the start point of the 12M21 feeder. Primary metering units on Brian Drive in Burford, on King St. in Burford (at Burford DS) and on Pleasant Ridge Road measure the outflow of power to Hydro One Networks. The difference is the consumption by Energy+. The primary metering unit on Pleasant Ridge Road is owned by Hydro One Networks.

The image below shows the map for Brian Drive, King Street, and Pleasant Ridge Road.



King Edward Street

A Hydro One Networks owned three phase 27.6kV primary metering unit is located on Pleasant Ridge Road where the Energy+ service area meets the Hydro One Networks service area. Hydro One Networks owns the main line 27.6kV 12M21 feeder from Brant TS to the primary metering unit location on Pleasant Ridge Road. The metering unit is required since the 12M21 feeder also supplies Energy+ load between Brant TS and Pleasant Ridge Road. Please refer to the map below for the location.



The source of the power is normally from a Hydro One Networks owned three phase 27.6kV line supplied from the Hydro One Networks owned Brant TS 12M22 feeder. Hydro One Networks owns the main line 12M22 feeder between Brant TS and King Edward Street in Paris. The Hydro One Networks owned feeder supplies Energy+ customers as it is running through the Energy+ service area. A primary metering unit at Brant TS measures the power at the start point of the 12M22 feeder. A primary metering unit on King Edward Street in Paris measures the outflow of power to Hydro One Networks. The difference is the consumption by Energy+. The primary metering unit on King Edward Street is owned by Hydro One Networks.

7-VECC-47

INTERROGATORY

Reference: Exhibit 7, pages 8-9 / Appendix 2-Q

b) Please provide the derivation of the 12% Administrative Burden used in Appendix 2-Q

RESPONSE

The 12% Administrative Burden was set in the original version of Appendix 2-Q which was developed in 2008 as part of the Cambridge and North Dumfries Hydro 2008 Incentive Regulation Mechanism (2008 IRM) Rate Application – Low Voltage Rates - EB-2007-0900. The Appendix was developed in conjunction with Cambridge and North Dumfries Hydro, Hydro One, OEB Staff and Waterloo North Hydro. There is no documentation available to show how the 12% was determined. In any event, the 12% is irrelevant since as part of the approved settlement agreement for the Cambridge and North Dumfries Hydro 2014 rate application, the direct costs for the embedded distributor from Appendix 2-Q are entered into tab I9 Direct Allocation of the cost allocation model. Then the cost allocation model by design adds the appropriate administrative costs to the direct costs.

7-VECC-47

INTERROGATORY

Reference: Exhibit 7, pages 8-9 / Appendix 2-Q

c) For each Embedded Distributor customer class, how was the "Total annual OM&A costs of asset class providing LV services" determined as input in Appendix 2-Q and why is the value the same for all classes?

RESPONSE

Based on the work done in 2008, the "Total annual OM&A costs of asset class providing LV services" is determined by adding the Energy+ amounts in accounts 5005, 5010, 5020, 5025, 5030, 5035, 5095, 5105, 5120, 5125, 5135 and 5160. It is the same amount for all classes since it is the total Energy+ system amount of which a portion (i.e. the amount in cell F35 of each version of Appendix 2-Q) is allocated to the embedded distributor.

7-VECC-47

INTERROGATORY

Reference: Exhibit 7, pages 8-9 / Appendix 2-Q

d) Why, in Appendix 2-Q, is the Original Asset Cost, Accumulated Depreciation and Annual Depreciation for Low Voltage Lines the same for all Embedded Distributor classes?

RESPONSE

The Original Asset Cost, Accumulated Depreciation and Annual Depreciation for Low Voltage Lines is the total Energy+ amounts for accounts 1830, 1835, 1850 and 1980. It is the same amount for all classes since a portion of the total Energy+ amount (i.e. the amount in cell F35 of each version of Appendix 2-Q) is allocated to the embedded distributor.

7-VECC-48

INTERROGATORY

Reference: **Exhibit 7, pages 5 and 10-15 / Cost Allocation Model, Tabs I6.1 and I8**

Preamble: **On page 5, Energy+ sets out the 2019 forecast kWh by customer class and the resulting Load Profile Scaling percentages used in the Cost Allocation. On page 10, Energy+ states that it has reflected a monthly peak of 28.8 MW for the Large Use customer with load displacement generation in the cost allocation model and rate design process.**

a) For 2019, what is the impact of the adjustment for load displacement generation on the billing demand for the Large Use class, i.e., the difference between the load displacement generation customer's forecast annual billing demand and 345.6 MW (12x28.8 MW)?

RESPONSE

It is the difference between the load displacement generation customer's 2016 annual billing demand and 345.34 MW (12x28.778 MW).

7-VECC-48

INTERROGATORY

Reference: Exhibit 7, pages 5 and 10-15 / Cost Allocation Model, Tabs I6.1 and I8

Preamble: On page 5, Energy+ sets out the 2019 forecast kWh by customer class and the resulting Load Profile Scaling percentages used in the Cost Allocation. On page 10, Energy+ states that it has reflected a monthly peak of 28.8 MW for the Large Use customer with load displacement generation in the cost allocation model and rate design process.

b) In Exhibit 3, the forecast 2019 billing kW for the Large Use class is 382,038 kW and the same value is used in Tab I6.1. Does this value include the adjustment for load displacement generation?

i. If yes, please show where/how in Exhibit 3 the kW forecast for the Large Use class is adjusted to account for the difference between the billed kW forecast for the load displacement customer and 28.8 MW / month.

ii. If no, what revisions are required to Tab I6.1

RESPONSE

The 382,038 kW includes the adjustment for load displacement generation.

i. The adjustment is not shown in Exhibit 3 but is reflected in the load forecast model tab Rate Class Load Model, cell D11. The adjustment in cell D11 is the difference outlined in the response to a).

ii. Not applicable.

7-VECC-48

INTERROGATORY

Reference: Exhibit 7, pages 5 and 10-15 / Cost Allocation Model, Tabs I6.1 and I8

Preamble: On page 5, Energy+ sets out the 2019 forecast kWh by customer class and the resulting Load Profile Scaling percentages used in the Cost Allocation. On page 10, Energy+ states that it has reflected a monthly peak of 28.8 MW for the Large Use customer with load displacement generation in the cost allocation model and rate design process.

c) It is noted that the Load Profile Scaling factor for the Large Use class is based on a 2019 forecast of 145.5 GWh, which is the same value as forecast in Exhibit 3.

How were the Large Use class load profiles set out in Tab I8 specifically adjusted to reflect a 28.8 MW monthly peak for the Large Use customer with load displacement generation?

RESPONSE

Please see response to 7–Staff-84 a).

7-VECC-49

INTERROGATORY

Reference: **Exhibit 7, page 5 / Exhibit 3, pages 25-26 and page 28 / Cost Allocation Model, Tabs I6.1 and I8**

Preamble: **It is noted that in Exhibit 3, page 26 the 2019 forecast energy for the GS 50-999 and GS 1000-4999 classes is 493.1 GWh and 231.0 GWh respectively and that these same values are used in Tab I6.1 of the Cost Allocation Model. However, in the case of the 2019 forecast billing demand for these classes the values are different. It is noted that the energy values referenced above are used to determine the Load Profile Scaling Percentages for the GS 50-999 and GS 1000-4999 classes.**

a) Is the difference between the billing demands for the GS 50-999 and GS 1000-4999 classes per Exhibit 3 versus the Cost Allocation model due to the fact the latter includes the billing demands for the WMPs in these classes? If not, what is the basis for the difference and where are the billing demands for the WMPs accounted for in Tab I6.1?

RESPONSE

The difference between the billing demands for the GS 50-999 and GS 1000-4999 classes per Exhibit 3 versus the Cost Allocation model is due to the fact the latter includes the billing demands for the WMPs in these classes.

7-VECC-49

INTERROGATORY

Reference: **Exhibit 7, page 5 / Exhibit 3, pages 25-26 and page 28 / Cost Allocation Model, Tabs I6.1 and I8**

Preamble: **It is noted that in Exhibit 3, page 26 the 2019 forecast energy for the GS 50-999 and GS 1000-4999 classes is 493.1 GWh and 231.0 GWh respectively and that these same values are used in Tab I6.1 of the Cost Allocation Model. However, in the case of the 2019 forecast billing demand for these classes the values are different. It is noted that the energy values referenced above are used to determine the Load Profile Scaling Percentages for the GS 50-999 and GS 1000-4999 classes.**

b) Please confirm that the energy values referenced in the Preamble for the GS 50-999 and GS 1000-4999 classes do not include the WMPs in those classes.

   i. If not confirmed, please indicate where/how in the Load Forecasts model the energy related to the WMPs has been included in the values for these classes.

   ii. If confirmed, please explain how the load associated with the WMPs in the GS 50-999 and GS 1000-4999 classes have been incorporated into the load profiles set out in Tab I8 of the cost allocation model.

RESPONSE

The energy values referenced in the Preamble for the GS 50-999 and GS 1000-4999 classes do not include the WMPs in those classes.

   i. Not applicable.

   ii. Please see response 7–Staff-85 a)

7-VECC-50

INTERROGATORY

Reference: Exhibit 7, page 18

a) Please explain why for each of the Embedded Distributor Customer classes the revenue to cost ratio has been decreased/increased such the proposed value is 100% as opposed to the max//min value for the OEB's policy range.

RESPONSE

This is consistent with approach taken to set the approved revenue to cost ratio for the Embedded Distributor Customer classes in the former Cambridge and North Dumfries Hydro 2014 Cost of Service Rate Application.

RATE DESIGN (EXHIBIT 8)

8-VECC-51

INTERROGATORY

Reference: Exhibit 8, page 5

a) Do the billing kWs used in the calculation of the fixed-variable split for the Large Use class include an adjustment to include the load that will be subject to a Standby Charge in 2019?

b) What is Energy+'s view as to whether the class' fixed/variable split percentage should or should not be calculated including the Standby load and why?

RESPONSE

a) The current fixed-variable split for the Large Use class excludes the revenue associated with the Standby Charge in 2019.

b) It is Energy+'s view that the class' fixed/variable split percentage should not include the revenue from the Standby load since it is not part of revenue at existing rates as the Standby charge currently does not exist.

8-VECC-52

INTERROGATORY

Reference: Exhibit 8, pages -8 / RRWF, Tab 12

a) What is the basis for the "current rates" set out in Tab 12 of the RRWF (i.e., fixed charge - $21.81 / variable charge - $0.0047/kWh)?

RESPONSE

The "current rates" set out in Tab 12 of the RRWF are a weighted average of the stand-alone rates using 2019 billing determinants as shown in Table 3-VECC-52, below.

Table 3-VECC-42: Current Rates

Service Territory	2019 Annualized Customers	Service Charge	2019 Fixed Distribution Revenue
CND	594,761	21.35	12,698,140
BCP	109,366	24.30	2,657,596
Total	704,127	21.81	15,355,736

Service Territory	2019 Annual kWh	Variable Rate	2019 Variable Distribution Revenue
CND	393,677,816	0.0046	1,810,918
BCP	72,390,462	0.0053	383,669
Total	466,068,279	0.0047	2,194,587

8-VECC-53

INTERROGATORY

Reference: Exhibit 8, pages 13-14

a) What wording is Energy+ proposing for purposes of describing how the monthly billing demand (kW) that the standby charge will apply to will be determined?

b) It is noted that for purposes of the RTSRs, Energy+ is proposing that the billing determinant for the Large User with load displacement generation be based on gross load (i.e., maximum coincident value of metered billing demand plus metered load displacement generation output). Please explain why the standby charge isn't also applied on the difference

c) Will the Standby Charge apply in all instances where a customer has load displacement generation or will it only apply in instances where the generation exceeds a certain capacity limit? If the latter, what are the proposed limits?

d) Please provide the proposed changes/additions to Energy+'s Conditions of Service as a result of implementing the Standby Charge.

RESPONSE

a) Energy+ will charge the customer for the amount drawn off the system at the customer's rate class distribution volumetric rate, and to charge the remainder up to the contact capacity amount at a standby rate mirroring the same distribution volumetric rate as the customer's rate class.

   Specifically, on a monthly basis the peak load taken by the customer will be determined by the load reading meter. The peak load will be charged the distribution volumetric rate for the rate class. If the load taken is less than the contact capacity amount, the difference between the contract capacity amount and the load taken will be charged a standby rate which will be equivalent to the distribution volumetric rate for the customer's rate class. If the load taken is equal to or greater than contact capacity amount the standby rate will not be applied.

b) Please refer to the Response to Interrogatory 7–Staff-77 b).

c) Please refer to the Response to Interrogatory 7–Staff-77 c).

d) Please refer to the Response to Interrogatory 7-Staff-77 h).

8-VECC-54

INTERROGATORY

Reference: Exhibit 8, pages 16-19 / RTSR Workforms

a) With respect to the BCP RTSR Workform – Tab 4 (RRR Data), please confirm that the 1.287 loss factor used for some of rate classes is correct. If so, please explain why it is so high. If not, please provide revised RTSR calculations

RESPONSE

Energy+ has revised the loss factor in BCP RTSR Workform from 1.287 to 1.0307 based on Appendix 2-R that was submitted on April 30, 2019 through the COS Application of EB-2018-0028, Appendix 8-5.

Attached are the revised RTSR_Workform models for each service territory with a revised loss factor.

2019_RTSR_Workform_20180712_BCP-8-Staff-87a.xlsm

2019_RTSR_Workform_20180712_CND-8-Staff-87a.xlsm

8-VECC-54

INTERROGATORY

Reference: Exhibit 8, pages 16-19 / RTSR Workforms

b) With respect to the RTSR Harm Workform, please explain how the load forecast was split between the BCP and CND service areas.

RESPONSE

Energy+ has used the 2019 load forecast for each service territory in the RTSR_Workform for each of the CND and Brant service territories. Please refer to 2019 Energy+ Load Forecast Excel Model, Tab “Summary CND” and Summary “BCP”.

8-VECC-54

INTERROGATORY

Reference: Exhibit 8, pages 16-19 / RTSR Workforms

c) With respect to the RTSR Harm Workform:

i. For those classes billed on a kWh basis, please indicate the basis for the loss factors used to convert the load forecast per Exhibit 3 to the values shown in Table 8-9.

ii. For those classes billed on a kW basis, please reconcile the total kW value shown in Table 8-9 with those in the load forecast in Exhibit 3.

iii. The Application (page 16, lines 28-31) indicates that the Large Use customer with load displacement generation will be billed on a gross load basis. However, the 2019 kW value used in the RTSR determination appears to be the same as that the load forecast per Exhibit 3 (382,032 kW). Please reconcile.

RESPONSE

i. Energy+ used the 2019 load forecast per Exhibit 3 and average loss factor of CND and Brant service territories in Table 8-9. The following Table 3-VECC-54c)(i) reconciles the total kWh shown in Exhibit 3 and Table 8-9.

Table 3-VECC-54c)(i) Load Forecast Reconciliation

	2019 Load Forecast Submitted Apr 30, 2018				
Customer Class	**Volume Metric**	**kWh (a)**	**Average Loss Factor (b)**	**Adjusted kWh (c = axb)**	**Total kWh Reported in Table 8-9**
Residential	kWh	466,068,279	1.0278	479,021,545	479,021,545
GS<50kW	kWh	195,276,256	1.0298	201,095,439	201,095,439
Unmetered Scattered Load	kWh	2,273,988	1.0257	2,332,319	2,332,319
Total		**663,618,523**		**682,449,303**	**682,449,303**

ii. Energy+ has provided the following Table 8-VECC-54c)(ii) to reconcile the total kW value shown in Table 8-9 with the load forecast in Exhibit 3.

Table 8-VECC-54c)(ii): Demand Value Reconciliation

	2019 Load Forecast Submitted Apr 30, 2018		WMP Allocation		Interval/Non-Interval Allocation		
Customer Class	Volume Metric	kW (a)	2017 Actual (%) (b)	kW (c = axb)	2017 Actual (%) (d)	kW (e = a+c)xd	Total kW Reported in Table 8-9
GS> 50 to 999 kW (Non-Interval)	kW	1,556,242	27%	18,069	34%	542,523	542,523
GS> 50 to 999 kW (Interval)					66%	1,031,789	1,031,789
GS> 1000 to 4999 kW	kW	542,178	73%	49,872		592,050.76	592,050.76
Large Use	kW	382,038				382,037.97	382,037.97
Sentinel Lighting	kW	343				342.92	342.92
Street Lighting	kW	15,467				15,467.36	15,467.36
Embedded WNH	kW	114,657				114,656.88	114,656.88
Embedded HON	kW	24,387				24,387.44	24,387.44
Embedded Distributor - Brantford	kW	1,075				1,074.96	1,074.96
Embedded Distributor - HON #1	kW	29,995				29,994.61	29,994.61
Embedded Distributor - HON #2	kW	102,973				102,972.91	102,972.91
Wholesale Market Participant	kW	67,942					
Total		**2,837,297**		**67,942**		**2,837,297**	**2,837,297**

iii. Energy+ used the kW in the load forecast. Energy+ recognizes this as an inconsistency however, moving the volume to a gross load value should have minimal impact on the RTSRs.

Energy+ would propose to update the RTSR rates to include the gross load billing kW at the time there is a final agreement on the use of gross load billing and the resulting billing determinants.

8-VECC-55

INTERROGATORY

Reference: Exhibit 8, pages 22-23

a) How much did Energy+ pay HONI in 2017 for LV service (i.e., ST charges)?

RESPONSE

Please refer to the response to Interrogatory 8-Staff-90 for the amount that Energy+ paid HONI in 2017 for LV service.

8-VECC-56

INTERROGATORY

Reference: Exhibit 8, page 24

a) Please provide the basis for the 1.0045 Supply Facilities Loss Factor and demonstrate that it accounts for both: i) the fact that Energy+ is partially an embedded utility and iii) the existence of FIT and/or microFIT generation in Energy+'s service area.

RESPONSE

The instructions associated with the completion of Appendix 2-R Loss Factors, indicate that if a utility is directly connected to the IESO-controlled grid, then the SFLF must be 1.0045, the figure that Energy+ has used. Although Energy+ is a partially embedded utility and has FIT and microFIT generation in its service territory, the quantities in these two areas are minimal compared to the quantities that are directly connected to the IESO-controlled grid and will not materially affect the calculation and in particular, will not materially impact the 5-Year average which is the basis upon which the SFLF is ultimately calculated.

Should the impact of embedded generation and the existence of FIT and microFIT generation in Energy+'s service area increase significantly in future years, an adjustment may be required.

8-VECC-57

INTERROGATORY

Reference: Exhibit 8, page 30

a) What would be the resulting Residential rates for 2019 if the transition to the fully fixed charge was extended one year (i.e., to 2020)?

b) What would be the resulting total 2019 bill impact for a low use Residential customer if the transition was extended one year?

RESPONSE

a) The resulting Residential rates for 2019 if the transition to the fully fixed charge was extended one year would be $26.12 per month plus $0.0026 per kWh

b) The following Table outlines the 2019 bill impacts for a low use Residential customer if the transition was extended one year.

Table 8-VECC-57: Impact of Extending Transition to Fully Fixed Rate

Bill Impacts	kWh	kW	Distribution (Fixed & Volumetric)				Total Bill (Excluding HST)			
			Current 2018	8-VECC-57 Scenario	$ Change	% Impact	Current 2018	8-VECC-57 Scenario	$ Change	% Impact
Residential - CND	313	-	$ 22.80	$ 26.93	$ 4.13	18.1%	$ 52.99	$ 59.00	$ 6.01	11.3%
Residential - BCP	357	-	$ 26.19	$ 27.05	$ 0.86	3.3%	$ 63.07	$ 63.43	$ .35	0.6%

8-VECC-58

INTERROGATORY

Reference: Exhibit 8, pages 84 and 97

a) Why is it necessary to have separate Rate Schedules for Residential customers in the former CND service area vs. the former Brant service area for 2019?

RESPONSE

The inclusion of separate Rate Schedules for Residential customers for 2019 is a result of approved rate riders from the Energy+ 2018 IRM Application, which are in effect until April 30, 2019 and service territory specific.

EXHIBIT 9 - DVAS

9-VECC-59

INTERROGATORY

Reference: Exhibit 9, Section 9.2

Preamble: IFRS related accounts 1575 and 1576 are calculated based on accounting changes beginning in 2013 (1576) or 2014 (1575). However, Brant County Power amalgamation was only effect January 1, 2016 (Exhibit 1, pg.12).

a) Given the timing of the Utilities' amalgamation why would it not be more appropriate to calculate and dispose of the balances of these accounts in proportion to the pre- and post-2016 impacts?

RESPONSE

Please refer to the response to Interrogatory 9-Staff-96 a) for an explanation of why Energy+ feels that it is appropriate to calculate a single rate rider to be charged to customers across both rate territories.

In addition, Energy+ believes that it would not be more appropriate to calculate and dispose of the balances of these accounts in proportion to the pre- and post- 2016 impacts for the following reasons:

- Based upon the distribution rate harmonization proposal, the harmonized distribution rates have been derived from the total rate base of Energy+. The 2019 rate base is comprised of the average asset balances for the 2019 Test Year. The average asset balances are not separated by service territory and the asset values incorporate the full transition to MIFRS, including the adjustments that were made for both the Brant and CND transition to MIFRS, the effect of which was captured by Accounts 1575 and 1576. Energy+ submits that the disposition of the total of Account 1575 and 1576 to all Energy+'s customers as one rate rider is consistent and aligns with the rate harmonization proposal which incorporates the impact of the change in asset values underlying rate base across all customers.

- This approach suggested by VECC in the pre-amble for Accounts 1575 and 1576 would be inconsistent with the harmonized approach proposed with respect to the disposition of all other variance accounts; and

- This approach suggested by VECC in the pre-amble would result in two different rate riders for each of CND and BCP customers – one rider for the pre 2016 and one rider for the post 2016; Energy+ submits that this would be confusing to customers and add an additional administrative burden to the recording of the DVA Account recovery/disposition.

9-VECC-59

INTERROGATORY

Reference: Exhibit 9, Section 9.2

Preamble: IFRS related accounts 1575 and 1576 are calculated based on accounting changes beginning in 2013 (1576) or 2014 (1575). However, Brant County Power amalgamation was only effect January 1, 2016 (Exhibit 1, pg.12).

b) If this were to be done would there be a material difference in the amounts owing to or from the customers in the respective BCP and CND service territories?

RESPONSE

The Table 9-VECC-59, below summarizes the allocation of the balances in Account 1575 and 1576 on the basis of pre January 1, 2016 balances allocated to each service territory, with the post January 1, 2016 balances allocated on a harmonized basis.

Table 9-VECC-59: Account 1575/1576 Allocation

	Brant	CND	Total				
	Up to Dec. 31, 2015	Up to Dec. 31, 2015	Up to Dec. 31, 2015	Energy+ (January 1, 2016 Onwards)	Total	Return (WACC)	Energy+ Balance for Recovery (Disposition)
Account 1575 Balance	-	675,512	675,512	1,122,368	1,797,880	110,390	1,908,270
Account 1576 Balance	(682,120)	-	(682,120)	(1,631,822)	(2,313,942)	(142,076)	(2,456,018)
	(682,120)	675,512	(6,608)	(509,454)	(516,062)	(31,686)	(547,748)

Based on the above table, there would be a disposition to Brant customers of $682,120 plus a portion of the disposition of $509,454 post January 1, 2016; and a recovery from CND customers of $675,512 less a portion of the disposition of $509,454 post January 1, 2016. Energy+ does not support this methodology as explained in response to part a).

9-VECC-60

INTERROGATORY

Reference: Exhibit 9, pages 5

a) Is a separate rate rider calculated for former CND and BCP service customers to collect their respective 1555 account balances?

RESPONSE

Energy+ has proposed to dispose of its deferral and variances accounts on a harmonized basis, and therefore separate rate riders have not been computed. The rate rider for 1555 account balances was calculated by consolidating the stranded meter deferral account from BCP and the smart meter capital from CND, and applying the total amount to consolidated billing determinants.

Appendix 3-VECC-23 d)

CDM Plan

ieso
Connecting Today.
Powering Tomorrow.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

May 16, 2018

Mr. Ed Glasbergen
Vice President, Business Development
Energy + Inc.
1500 Bishop Street
Cambridge, ON, N1R 5X6

Dear Ed:

RE: Conditional Approval of Amended CDM Plan

We refer to the CDM Plan submitted by Energy + Inc. and Westario Power Inc. and conditionally approved by the Independent Electricity System Operator (the "**IESO**") in the Conditional Approval of CDM Plan letter (the "**Conditional Approval Letter**") on November 13, 2017 (CDM Plan #: 201709290008), as amended. We acknowledge receipt of the proposed amended CDM Plan submitted on March 28, 2018 and updated on April 4, 2018, and April 12, 2018 (CDM Plan #: 201804120008) (the "**Amended CDM Plan**"). The Amended CDM Plan is submitted under section 2.4(a) of:

a) the Energy Conservation Agreement between the IESO and Cambridge and North Dumfries Hydro Inc. ("CND") dated December 31, 2014;

b) the Energy Conservation Agreement between the IESO and Westario Power Inc. dated October 19, 2015;

as amended (each, an "**Energy Conservation Agreement**" and together the "**Energy Conservation Agreements**").

Terms used but not defined in this letter that are defined in the Energy Conservation Agreements will have the meanings given to them in the applicable Energy Conservation Agreement.

The IESO approves the Amended CDM Plan, pursuant to section 2.4(a) of the Energy Conservation Agreement, subject to the terms and conditions set out below:

1. The Amended CDM Plan comprises the updated versions of the documents submitted by the LDCs set out at Schedule "A" and includes, for certainty, any information requests and responses thereto.

2. The LDCs each acknowledge and agree that no approval is being granted in respect of the assumptions made by the LDCs in Section G of the "Overview of CDM Plan".

3. The Program Rules that apply to each of the approved Programs are those in effect following the Program Start Date and as amended from time to time.

4. Except as otherwise agreed to in writing with the IESO, the LDCs will only accept applications under the Energy Conservation Agreements as of the applicable Program Start Dates set out in the Amended CDM Plan.

5. The LDCs will not accept applications under a Registered Initiative (as defined in the 2011-2014 Master CDM Program Agreement between each LDC and the IESO (in each case, or its predecessor, if applicable) dated January 1, 2011) on or after the applicable Program Start Date of its successor Program under the Energy Conservation Agreements.

6. The LDCs each acknowledge and agree that the LDCs have elected in the Amended CDM Plan not to deliver the province-wide Programs set out in Schedule "C" hereto and that the IESO may deliver in each LDC's service area any such province-wide Programs and any electricity savings attributable to such province-wide Programs will not be eligible electricity savings for the purposes of Section 2.3 of the Energy Conservation Agreements.

7. The LDCs each acknowledge and agree that the IESO may deliver in each LDC's service area any Programs identified in the Amended CDM Plan as "Centrally Delivered".

8. The LDCs each acknowledge and agree that each LDC will make available and deliver in its service area all province-wide Programs included in the Amended CDM Plan.

9. The LDCs represents that any inclusion of the Home Assistance Program (HAP) in this Amended CDM Plan is in accordance with the terms of the saveONenergy Home Assistance Program Cancellation Agreement between the IESO and LDCs, both executed on November 6, 2017.

10. The LDCs each acknowledge that each LDC's implementation of the Amended CDM Plan is based on each LDC's own assessment of its CDM Plan Target and CDM Plan Budget.

11. The LDCs each consent to the disclosure by the IESO of this letter and the Amended CDM Plan in its entirety, including, without limitation, to the public, except for anticipated annual budgets for Proposed Programs.

Please confirm your agreement to the above noted terms and conditions of this Amended CDM Plan approval by countersigning this letter and returning a copy to the IESO within 10 business days. For certainty, if the LDCs do not all countersign and return this letter to the IESO, the Amended CDM Plan approval will not be effective.

This approval may be signed and delivered by original or by email transmission and executed in any number of counterparts, and each executed counterpart will be considered to be an original. All executed counterparts taken together will constitute one agreement.

Should you have any questions or concerns, please do not hesitate to contact your LDC Business Advisor David Wilson at (416)506-2891.

Sincerely,

Terry Young

Vice-President - Policy, Engagement, and Innovation

Accepted:

ENERGY + INC.

By: ______________________ Date: May 17/2018

Name: Ian Miles

Title: President & CEO

Accepted:

WESTARIO POWER INC.

By: Tracey Vanness Date: May 16th 2018

Name:

Title: Executive Assistant, Executive - WPI

SCHEDULE "A"

Documents submitted to the IESO:

#	File	File Name	Date Submitted
All LDCs			
1	CDM Plan	CDM Plan Amendment 4.0 March 2018 REV-V2.2.xlsx	May 10, 2018
Energy + Inc.			
1	CE Tool	IESO CDM EE CE Tool Energy+ Amendment 4.0 March 2018.xlsm	April 4, 2018
2	LDC Authorization	Energy+ Authorization.pdf	April 4, 2018
Westario Power Inc.			
1	CE Tool	IESO CDM EE CE Tool Westario Power Amendment 4.0 March-18.xlsm	April 4, 2018
2	LDC Authorization	Westario Authorization.pdf	April 4, 2018

SCHEDULE "C"

Province-wide Programs that the LDCs have elected to not offer:

Province-wide Program	LDC's Program End Date (if applicable)	End Date of Central Delivery
Business Refrigeration Incentive Program	December 31, 2020	December 31, 2018

OVERVIEW OF CDM PLAN
This CDM Plan must be used by the LDC in submitting a CDM Plan to the IESO under the Energy Conservation Agreement between the LDC and the IESO The CDM Plan will consist of the information provided in this document and any additional information and supporting documents provided by the LDC to the IESO in support of this CDM Plan. Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Energy Conservation Agreement as may be applicable.
Complete all fields within the CDM Plan that are applicable. Where additional space is required to complete a section of the CDM Plan, please append additional pages as required. The LDC should indicate that additional information has been attached in the related question field on the CDM Plan. Please refer to the CDM Plan Submission and Review Criteria Rules for further information.

A. General Information

1.

CDM Plan Submission Date: ***(DD-Mon-YYYY)***	28-Mar-2018
CDM Plan Version	Amendment No. 4

2.

LDC INFORMATION										
	LDC 1	**LDC 2**	**LDC 3**	**LDC 4**	**LDC 5**	**LCD 6**	**LCD 7**	**LCD 8**	**LCD 9**	**LCD 10**
LDC Name:	Energy + Inc.	Westario Power Inc.								
Company Representative:										
Name:	Ian Miles	Tracey Vanness								
Title:	President & CEO	Senior Exec. Asst.								
Email Address:	imiles@energyplus.ca	tracey.vanness@westario.com								
Phone Number (XXX-XXX-XXXX):	519-239-9715	(519) 507-6666								

3.

Primary Contact for CDM Plan	
Name:	Ed Glasbergen
LDC Name:	Energy+ Inc.
Title:	Vice President, Business Development
Email Address:	eglasbergen@energyplus.ca
Phone Number (XXX-XXX-XXXX):	519-621-8405 x2420

Estimated Start Date of CDM Plan: ***(DD-Mon-YYYY)***	1-Jan-2016

LDC CONFIRMATION FOR CDM PLAN	
Each LDC to this CDM Plan has executed the Energy Conservation Agreement.	Yes
A completed Cost-Effectiveness Tool is attached and forms part of the CDM Plan.	Yes
A completed Achievable Potential Tool is attached and forms part of the CDM Plan.	Yes
All customer segments in each LDC's service area are served by the Programs set out in this CDM Plan.	Yes
The CDM Plan includes all electricity savings attributable to all Programs and pilot programs that have in-service dates between Jan 1, 2015 and December 31, 2020.	Yes
The CDM Plan Budget for each LDC includes all eligible funding under the full cost recovery and pay-for-performance mechanisms for Programs under its CDM Plan.	Yes
Frequency of LDC Invoicing to IESO (subsequent changes to the frequency should be notified to us by email).	Monthly

COMPLETE FOR CDM PLAN AMENDMENTS ONLY		
Select the reason(s) for CDM Plan amendment, as per ECA.		
One time each calendar year of the term		
LDC wishes to request an adjustment to the CDM Plan Budget		
The amendments to a provision of the ECA or any Rules will have a material effect on the CDM Plan		
LDC's actual spending under CDM Plan has exceeded (or is reasonably expected to exceed) the portion of the CDM Plan Budget allocated to the current year of the term		
Under a joint CDM Plan, LDCs that are parties to a joint CDM Plan reallocate any portion of their respective CDM Plan Targets and CDM Plan Budgets [*Reallocation not subject to IESO approval*]		
IESO has triggered remedies under Article 5 of the ECA		
LDC seeking to change its selection of the type of funding that it wishes to receive for each Program in the CDM Plan [ECA, section 4.1]		
Other (Please specify reason)	Submitting Joint Plan	Yes

B. LDC Authorization

LDC DECLARATION
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.

LDC	
I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the IESO and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the IESO (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.	
LDC's Legal Name:	Energy+ Inc.
Company Representative:	Ian Miles, President & CEO
Signature	
	I/We have the authority to bind the Corporation.
Date (DD-Mon-YYYY)	28-Mar-2018

C. CDM Plan Summary

TABLE 1: SUMMARY OF CDM PORTFOLIO SAVINGS AND BUDGET												
		CDM PLAN TOTAL	**LDC 1**	**LDC 2**	**LDC 3**	**LDC 4**	**LDC 5**	**LCD 6**	**LCD 7**	**LCD 8**	**LCD 9**	**LCD 10**
a.	**Allocated LDC CDM Plan Target (MWh)** *Indicate total CDM Plan Target allocated to LDC(s)*	**123,960**	100,950.0	23,010.0								
b.	**CDM Plan MWh Savings** *Calculated as part of CDM Plan*	**186,426**	163,416	23,010								
c.	**Allocated LDC CDM Plan Budget ($)** *Indicate total budget allocated to LDC*	**$31,974,340**	$25,873,071.00	$6,101,269.00								
d.	**Total CDM Plan Budget ($)** *Calculated as part of CDM Plan*	**$26,759,821**	$20,658,552	6,101,269								
f.	**CDM Plan Cost Effectiveness**		**Total Resource Cost (TRC)**			**Program Administrator Cost (PAC)**			**Levelized Cost**			
		Program Year	**Benefits ($)**	**Costs ($)**	**Ratio**	**Benefits ($)**	**Costs ($)**	**Ratio**	**($/kWh)**			
	Indicate annual portfolio-level Cost Effectiveness for CDM Plan as determined by LDC(s) using output from Cost-Effectiveness Tool	2015	$80,197,326.89	$19,421,197.18	4.1	$70,096,362.21	$0.00	#DIV/0!	$0.000	#DIV/0!		
		2016	$11,292,566.79	$9,287,110.50	1.2	$9,853,238.93	$3,846,089.82	2.6	$0.025			
		2017	$11,681,877.57	$10,110,406.51	1.2	$10,216,305.31	$4,048,647.09	2.5	$0.028			
		2018	$22,972,711.69	$17,236,551.03	1.3	$20,037,687.40	$7,859,840.22	2.5	$0.031			
		2019	$13,596,609.29	$10,865,712.78	1.3	$11,884,554.87	$5,111,345.24	2.3	$0.034			
		2020	$11,157,561.93	$9,304,538.76	1.2	$9,763,644.13	$4,303,115.67	2.3	$0.035			
		CDM Plan Total	**$150,898,654**	**$76,225,517**	2.0	**$131,851,793**	**$25,169,038**	5.2	**$0.014**			
g	**Plan Cost Effectiveness-Exceptions Rationale** *Complete this section if proposed plan <u>does not</u> meet minimum Cost-Effectiveness Thresholds set out in CDM Plan Submission and Review Criteria Rules.*											

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	Energy + Inc.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Audit Funding Program			1-Jan-2016			Yes	Yes	Yes	Yes	Yes			$7,837	26	$7,770	26	$7,290	26	$8,765	26	$9,473	26	$41,134	105
	Business Refrigeration			1-Dec-2017			Yes	Yes		Yes				$0	0	$151,576	313	$287,501	626	$96,798	188	$67,905	125	$603,779	1,253
	Existing Building Commissioning			1-Dec-2017				Yes		Yes				$0	0	$93	1	$58	1	$114	1	$141	1	$405	1
	Energy Manager Program			1-Dec-2017				Yes		Yes	Yes			$0	0	$93	1	$58	1	$114	1	$141	1	$405	1
	High Performance New Construction			1-Jan-2016			Yes	Yes	Yes	Yes				$80,780	441	$85	1	$58	1	$114	1	$141	1	$81,177	442
	Monitoring and Targeting Program			1-Dec-2017							Yes			$0	0	$93	1	$58	1	$114	1	$141	1	$405	1
	Process and Systems Upgrades Program			1-Jan-2016				Yes	Yes	Yes	Yes			$0	0	$234,750	0	$4,019,254	15,270	$850,726	2,400	$140	0	$5,104,869	17,670
	Retrofit			1-Jan-2016			Yes	Yes	Yes	Yes	Yes			$1,360,836	7,455	$1,446,250	8,960	$1,205,635	7,455	$1,624,071	7,455	$1,824,790	7,455	$7,461,582	38,602
	Small Business Lighting			1-Apr-2016			Yes							$0	0	$125,000	279	$368,123	1,395	$304,416	1,395	$161,967	558	$959,505	3,627
	Coupon Program			1-Jan-2016	Yes	Yes								$691,742	4,849.0	$450,000	3,222.7	$447,757	3,222.7	$668,091	3,222.7	$768,826	3,222.7	$3,026,416	17,740
	Home Assistance Program			1-Jan-2016		Yes								$0	0.0	$75	1.0	$0	0.0	$0	0.0	$0	0.0	$75	0
	Heating and Cooling Program			1-Jan-2016	Yes									$741,021	1,480.4	$568,082	1,116.9	$527,263	1,116.9	$578,013	1,116.9	$601,215	1,116.9	$3,015,593	5,948
	New Construction Program			1-Jan-2016	Yes									$0	0.0	$75	1.0	$50	1.0	$95	1.0	$116	1.0	$336	1
	Smart Thermostat Program			17-Dec-2017	Yes													$10,290	32.3	$10,290	32.3	$10,290	32.3	$30,871	97.0
		Pool Pump Local Program		1-May-2018	Yes													$74,000	149.2	$129,000	373.1	$129,000	373.1	$332,000	895.4
FCR TOTAL												$0	0	$2,882,216	14,252	$2,983,939	13,924	$6,947,394	29,299	$4,270,720	16,214	$3,574,284	12,915	$20,658,552	86,382.7461
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Audit Funding												152												0.0
	Energy Manager (PSUI)												1,690												1,295.9
	Other												818												817.6
	Process and Systems Upgrades Program												58,956												58,955.8
	Retrofit Initiative												13,350												13,049.1
	Direct Install Lighting												169												87.1
	High Performance New Construction												134												134.0
	Other												24												0.0
	Bi-Annual Retailer Event												1,657.8												1,633.6
	Low Income Home Assistance Program												22.9												16.4
	Heating and Cooling Initiative												833.4												833.4
	Residential New Construction												210.3												210.3
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	78,017											0.0	77,033
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	78,017.1	$2,882,216	14,252.0	$2,983,939	13,924.5	$6,947,394	29,298.9	$4,270,720	16,214.3	$3,574,284	12,914.6	$20,658,552	163,416
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		False		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 2:	Westario Power Inc.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Retrofit			1-Jan-2016			Yes	Yes	Yes	Yes	Yes			$355.915	867.0	$432.287	1.441.6	$378.915	1.518.1	$412.440	1.518.1	$442.380	1.518.1	$2,021,937	6.862.9
	Small Business Lighting			1-Jan-2016			Yes							$8.198	0.0	$31.452	70.2	$631.703	1.544.4	$166.769	387.5	$173.750	384.7	$1,011,871	2.386.8
	Audit Funding Program			1-Jan-2016				Yes	Yes	Yes	Yes			$6.457	65.7	$16.400	213.8	$39.484	213.8	$44.152	213.8	$48.476	213.8	$154,968	855.2
	Existing Building Commissioning			1-Jun-2017				Yes	Yes	Yes	Yes			$0	0.0	$0	0.0	$1	1.0	$1	1.0	$1	1.0	$3	1.0
	Energy Manager Program			1-Jun-2017				Yes	Yes	Yes	Yes			$0	0.0	$0	0.0	$1	1.0	$1	1.0	$1	1.0	$3	1.0
	Monitoring and Targeting Program			1-Jun-2017				Yes	Yes	Yes	Yes			$0	0.0	$0	0.0	$1	1.0	$1	1.0	$1	1.0	$3	1.0
	Process and Systems Upgrades Program			1-Jan-2016				Yes	Yes	Yes	Yes			$0	0.0	$0	0.0	$0	0.0	$153,857	409.5	$0	0.0	$153,857	409.5
	High Performance New Construction			1-Jan-2016				Yes	Yes	Yes				$10,928	52.8	$11,496	58.4	$16,247	58.4	$17,522	58.4	$18,703	58.4	$74,898	286.4
	Business Refrigeration Incentive Program - Centrally Delivered			1-Jun-2017			Yes							$0	0.0	$0	0.0	$2,009	6.7					$2,009	6.7
	Business Refrigeration Incentive Program - LDC Delivered			1-Jan-2019			Yes													$87,562	200.5	$91,610	200.5	$179,172	401.0
	Coupon Program			1-Jan-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes			$318.908	1.720.4	$264.571	1.246.0	$184.537	664.6	$223.678	747.6	$265.073	830.7	$1,256,767	5.138.6
	Home Assistance Program			1-Jan-2016		Yes								$32.730	20.1	$181.885	214.1	$0	0.0	$0	0.0	$0	0.0	$214,614	234.2
	New Construction Program			1-Jan-2016	Yes									$1,847	0.0	$1,936	0.0	$1	1.0	$1	1.0	$1	1.0	$3,786	1.0
	Heating and Cooling Program			1-Jan-2016	Yes									$305,813	234.9	$236,079	180.1	$83,336	59.8	$84,639	59.8	$85,845	59.8	$795,711	594.5
	Smart Thermostat Program			17-Dec-2017	Yes													$6,300	10.5	$6,300	10.5	$6,300	10.5	$18,900	31.5
		Home Assessment Pilot Westario Power		1-Apr-2016	Yes									$0	413.5	$0	0.0	$0	0.0	$0	0.0	$0	0.0		413.5
		Instant Savings Local Program Westario Power Inc. CFF		1-Jun-2017	Yes									$0	0.0	$52,168	193.5	$50,997	270.9	$65,042	309.6	$44,564	193.5	$212,770	967.4
FCR TOTAL												$0	0.0	$1,040,796	3,374.4	$1,228,274	3,617.8	$1,393,532	4,351.1	$1,261,965	3,919.3	$1,176,703	3,474.0	$6,101,269	18,592.2
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Retrofit Initiative												3.066												3.055.4
	Direct Install Lighting												339												205.6
	High Performance New Construction												26												26.4
	Audit Funding												76												76.1
	Conservation Instant Coupon Booklet												827.7												815.4
	Low Income Home Assistance Program												160.5												122.3
	Residential New Construction												0.0												0.0
	Heating and Cooling Initiative												116.6												116.6
	Other												104.1												0.0
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	4,716.1											0.0	4,418
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	4,716.1	$1,040,796	3,374.4	$1,228,274	3,617.8	$1,393,532	4,351.1	$1,261,965	3,919.3	$1,176,703	3,474.0	$6,101,269	23,010.0
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

E. Proposed Local and Regional Pilot CDM Programs

Notes
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by the IESO. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.

TABLE 3a. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3b. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3c. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3d. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3e. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3f. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3g. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3h. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3i. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3j. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

F. Detailed Information on Collaboration and Regional Planning

ADDITIONAL DETAILED INFORMATION	
Regional LDC(s) Collaboration *Description of how the LDC(s) will collaborate with other LDCs. If collaboration will not occur, description of why it will not occur.*	Cambridge and North Dumfries Hydro (CND) has been a long standing example of LDC collaboration with its neighbouring LDCs, Kitchener-Wilmot Hydro (KWH) and Waterloo North Hydro (WNH). Through the previous framework and continuing into the Conservation First the intent is to share procurement, media buys and delivery strategies where it makes sense. Joint customer and stakeholder outreach will also continue as a core strategy for success. Through CND's acquisition of Brant County Power (BCP) efforts will be made to collaborate where possible with other neighbouring LDCs like Brantford Power and the Niagara Region through the NEPA group. The staff at CND participates as members of the Consumer Working Group, Connected Home Subcommittee, Association of Energy Services Professionals and Quest Combined Heat and Power Consortium.
Gas Collaboration *Description of how the LDC(s) will collaborate with other gas utility programs delivered in service area (if applicable). If collaboration will not occur, description of why it will not occur.*	CND is working very closely with representatives at Union Gas, both from a local delivery and from a program design standpoint. Efforts will continue to jointly market to customers and educate about energy management practices. Meetings have been set bi-annually to bring together all parties in the Waterloo Region including the Water Efficiency group at the Region of Waterloo. As part of future program design, CND will make a concerted effort to engage Union Gas to achieve cost effectiveness and improved offers. Additional support is being given to the Region of Waterloo on the development of a Community Energy Plan. Both Union Gas and CND are supporting this initiative along with KWH and WNH.
CDM Contribution to Regional Planning *Description of how the CDM Plan considers the electricity needs and investments identified in other plans or planned initiatives, completed or underway within the LDC(s)' service area or region. This may included Integrated Regional Resource Plans or Municipal Community Energy Plans.*	The Draft Kitchener-Waterloo-Cambridge-Guelph Integrated Regional Resource Plan (IRRP) has been prepared by a Technical Working Group comprised of the aforementioned LDCs, the IESO and Hydro One. CND staff participated on a conservation subcommittee during the creation of the IRRP and have been given continual opportunity for input. Section 2.1 (1) of the draft IRRP recommends both aggressive attainment of the conservation targets and a focus on distribution-connected generation. Both CND and BCP are actively involved in their respective IRRPs and both acknowledge that the CDM plan will contribute to the Regional Planning Process. Sarah Colvin, Energy Efficiency Manager for both CND and BCP is committed to supporting the implementation phase of the IRRP as it relates to the activities included in the CDM plan. CND has been supporting the connection of a 9.2MW Conservation CHP project with a large industrial customer. This project will support CND's Conservation Target and ease the grid constraint in an industrial park on the north side of Cambridge. CND currently has an approved IESO funded pilot in market that is evaluating the demand response load shift and energy efficiency of smart thermostats. This information will be used as insight into future Regional Planning based on the evaluated outcomes expected in Q2 2016.

G. Additional Documentation for CDM Plan (If applicable)

ADDITIONAL INFORMATION AND DOCUMENTATION	
Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 province-wide programs*	Key Assumptions & Criteria Retrofit Used 2015/16 average for application quantity and savings/project Used 2016 results for incentive costs, VA costs and NTG Projected flat to 2020 Audit Used 2015/16 average for application quantity and savings/project Used 2016 results for incentive costs, VA costs and NTG Projected flat to 2020 PSUP Used known pipeline Discounted Galt Wastewater project by 50% - application pending Used 1 MWh/$1 placeholder in years without FIRM prospects SBL Used Burman numbers provided by Energy+ HPNC No known projects Used 1 MWh placeholder in empty years M&T No known projects Used 1 MWh placeholder in empty years Energy Manager
Approved Local and/or Regional Programs and Pilot Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 local or regional programs or pilot programs*	CND currently has an approved pilot underway to evaluate the demand and energy savings associated with smart thermostat technologies. The IESO has funded a pilot using Nest thermostats and the Rush Hour Rewards demand response offer which launched in July, 2014. The pilot is anticipated to complete in Q4, 2015. The offer has been extended to customers of BCP.
Proposed Local and/or Regional Programs and Pilot Programs *Opportunity to provide additional information on assumptions used for forecast budgets and/or savings for proposed programs or pilot programs*	At this time, CND & BCP do not have any proposed local/regional or pilot programs to report on. Efforts will be made to continually monitor the market for cost-effective programs. CND & BCP do acknowledge that behaviour-based customer engagement programs are going to become more viable in the later years of the framework and will likely submit a program at a later date.
Programs from 2011-2014/2015 CDM Framework *Opportunity to provide any additional information on assumptions used for budgets and/or savings from existing 2011-2014/2015 CDM Programs*	CND & BCP have a strong pipeline of projects in the business sector which are projected to deliver significant GWh. Programs with long application lead times will transition to the new framework by September, 2015 while others will continue under the extension until December 31st. CND has a large combined heat and power generation project which is still on track to be in service for December 2015. This project is anticipated to provide a significant contribution towards CND's conservation target.
Programs funded through Pay-for-Performance *Opportunity to provide any additional information on assumptions used for budgets and/or savings for Pay for Performance Programs*	This section has been intentionally left blank
Other *Additional assumptions used in the CDM Plan*	This section has been intentionally left blank

Energy+ Inc.
EB-2018-0028
Response to VECC Interrogatories
Page 156 of 156
Filed: September 14, 2018

Summary of Changes to CDM Template

Version No.	Date	Tab	Change Summary
2	20-Jan-15	A. General Information	Inclusion of "Company Name" for Primary Contact
			Inclusion of frequency of invoicing (monthly vs. quarterly)
			Update date format to eliminate confusion
			Change reference to OPA
			Additional LDCs for joint plan
		B. LDC Authorization	Update date format to eliminate confusion
		D. CDM Plan Milestone LDC 1-10	Additional line items for FRC program names
			Additional LDCs for joint plan
			Update on the program names
			Update date format to eliminate confusion
			Update column headers: - "Province Wide Program Name" - "Proposed Regional or Local CDM Program or Pilot Program Name"
			Change reference to OPA
			Update Header and Footer
		E.. Proposed Program&Pilots	Additional boxes for proposed programs
			Update date format to eliminate confusion
		C. Detailed Information	Clarity if it is primary LDC or all LDCs in a joint CDM Plan.