EB-2018-0028

IN THE MATTER OF the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, Sched. B, as amended (the "Act");

AND IN THE MATTER OF an Application by Energy+ Inc. under Section 78 of the Act for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2019.

RESPONSE TO COMMENTS ON THE DRAFT RATE ORDER

OF

ENERGY+ INC.

July 18, 2019

1. Gross Load Billing, Retail Transmission Service Rates (RTSRs) and Low Voltage Rates

Background

To reflect the OEB's Decision on the standby charge proposal, Energy+ adjusted the load forecast for the GS>50 to 999 kW, GS > 1,000 to 4,999 kW, and Large Use classes to remove the standby adjustments related to the load displacement generation (LDG).[1]

Energy+ also updated the 2019 Expected CDM Savings by Rate Class for the LRAM Variance Account to include a CDM adjustment for the energy and billing demand associated with PSUP projects.[2]

Comments Received on RTSRs:

a) OEB Staff commented that there was an adjustment of 6,409 kW to the GS>50 to 999 kW class for the calculation of RTSR connection rate. OEB Staff requested an explanation for the nature of this adjustment.[3]

   VECC commented that the 2019 billing determinant for the GS 50-999 kW and GS 1,000-4,999 class kW classes inclusive of market participants differed from the billing determinants in the RTSR model for Network and Connection rates.[4]

b) OEB Staff commented that there was no adjustment to the GS>1000 to 4999 kW class for the calculation of RTSR connection rates despite the removal of the standby adjustment in the GS>1000 to 4999 kW class which indicated that there will be LDG(s) in the 2019 test year. OEB Staff requested an explanation for whether or not an adjustment to the RTSR connection load determinant is required.[5]

   VECC commented that for the GS 1,000-4,999 class they would have expected there to be a difference between the billing determinants for Network and Connection in order to account for

[1] Draft Rate Order, Page 20, Table 11.
[2] Draft Rate Order, Page 21, Table 12
[3] OEB Staff Submission on Draft Rate Order, page 4
[4] VECC Submission on Draft Rate Order, page 3
[5] OEB Staff Submission on Draft Rate Order, page 4

the fact the latter is billed on a gross load basis and the class' customers are implementing a PSUP project.

Energy+ Response on RTSRs:

Energy+ agrees with the comments from OEB Staff and VECC with respect to the RTSR billing determinants. Energy+ has corrected and reconciled the RTSR billing determinants with the load forecast. Energy+ notes that RTSR billing determinants that are on a kWh basis differ from the load forecast as they are loss adjusted. Energy+ has provided an updated RTSR Model as part of this submission to reflect the corrections.

Energy+ has updated the RTSR Connection billing determinants to include the load from PSUP projects included in the 2019 Test Year Load Forecast. The adjustments have been made in the GS > 50-999 kW and GS > 1000-4999 kW classes and are consistent with the CDM adjustments removed from the Load Forecast Model as part of the Draft Rate Order submission.

Table 1: Revised RTSR Network and Connection Rates provides the revised billing determinants and RTSR rates for Network and Connection and illustrates the differences between the billing determinants as a result of the implementation of Gross Load Billing (applicable for RTSR Connection only).

Table 2: Load Forecast Adjustments summarizes the adjustments made to the load forecast as part of the Draft Rate Order submission. The adjustments to the billing determinants for the GS > 50-999 kW and GS > 1000-4999 kW classes in Table 1 are consistent with the adjustments to the load forecast as a result of the removal of standby.

Table 1: Revised RTSR Network and Connection Rates

Network	Loss Adjusted kWh / kW	2019 Rate	$
Residential	475,613,262	0.0060	$ 2,863,032
GS< 50kW	199,918,821	0.0054	$ 1,076,166
GS > 50-999 kW (Non Interval)	539,150	3.1657	$ 1,706,814
GS > 50-999 kW	1,025,619	3.1878	$ 3,269,458
GS >1000-4999 kW	552,369	2.3178	$ 1,280,254
Large Use	330,833	2.3839	$ 788,679
Street Lighting	10,945	1.6865	$ 18,459
Sentinel Lighting	343	1.8501	$ 634
Unmetered Scattered Load	2,343,765	0.0052	$ 12,289
Embedded WNH	114,657	2.3839	$ 273,333
Embedded HON	24,387	2.3839	$ 58,138
Embedded - Brantford	1,075	2.6625	$ 2,862
Embedded - HON #1	29,011	2.6625	$ 77,242
Embedded - HON #2	-	-	$ -
Total			**11,427,360**

Connection	Loss Adjusted kWh / kW	2019 Rate	$	Billing Determinant Difference
Residential	475,613,262	0.0045	$ 2,117,500	-
GS< 50kW	199,918,821	0.0041	$ 811,588	-
GS > 50-999 kW (Non Interval)	539,150	2.3638	$ 1,274,429	-
GS > 50-999 kW	1,029,406	2.3876	$ 2,457,826	3,787
GS >1000-4999 kW	588,206	1.6403	$ 964,851	35,837
Large Use	405,209	1.6548	$ 670,557	74,376
Street Lighting	10,945	1.2650	$ 13,846	-
Sentinel Lighting	343	1.2233	$ 419	-
Unmetered Scattered Load	2,343,765	0.0041	$ 9,681	-
Embedded WNH	114,657	2.0269	$ 232,395	-
Embedded HON	24,387	2.0269	$ 49,430	-
Embedded - Brantford	1,075	1.6731	$ 1,798	-
Embedded - HON #1	29,011	1.6731	$ 48,537	-
Embedded - HON #2	-	-	$ -	-
Total			**8,652,856**	

Table 2: Load Forecast Adjustments

	Decision		Settlement		Difference	
Rate Class	*kWh*	*kW*	*kWh*	*kW*	*kWh*	*kW*
Residential	461,453,716		461,453,716		-	-
General Service < 50 kW	193,967,011		193,967,011		-	-
General Service > 50 to 999 kW	490,088,356	1,546,700	491,288,356	1,550,487	(1,200,000)	(3,787)
General Service > 1000 to 4999 kW	214,108,990	502,496	229,378,990	538,334	(15,270,000)	(35,837)
Direct Market Participants (GS > 50 to 999 kW)		18,069		18,069	-	-
Direct Market Participants (GS > 1000 to 4999 kW)		49,872		49,872	-	-
Large Use	145,141,006	330,833	145,141,006	361,276	-	(30,443)
Street Lights	3,798,281	10,945	3,798,281	10,945	-	-
Sentinel Lights	126,989	343	126,989	343	-	-
Unmetered Loads	2,273,988		2,273,988	-	-	-
Embedded Distributor - Hydro One, CND	12,605,162	24,387	12,605,162	24,387	-	-
Embedded Distributor - Waterloo North, CND	58,104,381	114,657	58,104,381	114,657	-	-
Embedded Distributor - Brantford Power, BCP	347,757	1,075	347,757	1,075	-	-
Embedded Distributor - Hydro One #1, BCP	12,191,720	29,011	12,191,720	29,011	-	-
Embedded Distributor - Hydro One #2, BCP	43,274,122	102,973	43,274,122	102,973	-	-
Total	1,637,481,480	2,731,362	1,653,951,480	2,801,430	(16,470,000)	(70,068)

Note: kWh figures are not adjusted for losses

Comments Received on Low Voltage Charges:

a) OEB Staff submitted that "Low Voltage Services" should be removed from the proposed Gross Load Billing wording because Energy+ is not charged on a gross load basis by its host distributors for sub-transmission charges.[6]

b) VECC noted that any revisions made to the billing determinants for Connections will impact the allocation of LV costs and the subsequent derivation of LV rates.[7]

[6] OEB Staff Submission on Draft Rate Order, page 4
[7] VECC Submission on Draft Rate Order, page 3

Energy+ Response on Low Voltage Charges:

Energy+ agrees with the comment from OEB Staff and has removed the reference to Low Voltage Services from the Gross Load Billing Section of the Tariff Schedule. The revised wording is as follows:

GROSS LOAD BILLING

The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss adjusted demand supplied from the distribution system plus (b) the demand that is supplied by embedded generation installed after October 30, 1998, which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for loss.

Energy+ agrees with VECC's comment that revisions to the billing determinants for purposes of RTSR will impact the allocation of Low Voltage costs ("LV") and the derivation of the LV charges. Energy+ has updated the allocation of Low Voltage costs and Low Voltage rates based on the revised RTSR Connection rates. Table 3: Low Voltage Allocation and Rates summarizes the revised calculations.

Table 3: Low Voltage Allocation and Rates

Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	126,466	461,453,716		kWh	$ 0.0003	
GS < 50 kW	48,471	193,967,011		kWh	$ 0.0002	
GS >50 to 999 Kw	227,683		1,564,769	kW		$ 0.1455
GS >1000 to 4999 kW	55,774		552,369	kW		$ 0.1010
Large Use	33,701		330,833	kW		$ 0.1019
Street Lighting	852		10,945	kW		$ 0.0779
Unmetered and Scattered	578	2,273,988	0	kWh	$ 0.0003	
Sentinel Lighting	26		343	kW		$ 0.0753
Embedded Distributor - HON, CND	0		24,387	kW		$ -
Embedded Distributor - WNH	14,305		114,657	kW		$ 0.1248
Embedded Distributor - HON 1	0		29,011	kW		$ -
Embedded Distributor - BPI	111		1,075	kW		$ 0.1030
Embedded Distributor - HON 2	0		102,973	kW		$ -
TOTALS	**507,967**	**657,694,715**	**2,731,362**			

Comments Received on 2019 Expected CDM Savings by Rate Class for LRAM Variance Account:

a) VECC questioned why the LRAMVA threshold values changed for all rate classes when the CDM adjustments that were made only affected the GS 50-999 kW and GS 1,000-4,999 kW classes. VECC expected the changes to be limited to the GS 50-999 kW and GS 1,000-4,999 kW classes and be equal to the annualized impacts of the PSUP projects now included in the CDM adjustment.[8]

Energy+ Response on LRAMVA Threshold:

Energy+ agrees with VECC's comments on the LRAMVA Threshold. Energy+ has corrected the LRAMVA thresholds to limit the changes to the GS > 50-999 kW and GS > 1000-4999 kW Classes and to reflect an adjustment equal to the annualized impacts of the PSUP projects included in the Load Forecast.

The revised LRAMVA threshold is presented in Table 8: Revised LRAMVA Threshold and compares to the amounts from the Settlement Proposal presented in Table 9: Settlement Proposal LRAMVA Threshold.

Table 8: Revised 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	12,316,083	23,436,186	1,749,897	7,582,887	75,999,899
2019 kW - Annual			38,869	55,003	3,989	21,852	119,712
2019 kW - Monthly			3,239	4,584	332	1,821	9,976

Table 9: Settlement Proposal LRAMVA Threshold

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

[8] VECC Submission on Draft Rate Order, page 2

2. Cost Allocation Model

Background

Energy+ provided an updated Cost Allocation Model as part of the revisions required pursuant to the Board's Decision.

Comments Received on Cost Allocation Model

a) OEB Staff did not understand the reason for the change to number of bills issued to the Large Use class. They noted that with two customers in the Large Use rate class, being billed on a monthly basis, would require 24 bills per year.[9]

b) VECC reviewed the Cost Allocation Model filed with the DRO and the revenue to cost ratio proposals set out in the Revenue Requirement Work Form and apart from the issue noted by OEB Staff regarding the number of bills attributed to the Large Use class, had no issues with Energy+'s revisions related to cost allocation.[10]

Energy+ Response to Cost Allocation

Energy+ agrees with OEB Staff and VECC that the number of bills issued to the Large Use class should be 24 bills per year (2 customers x 12 bills). Energy+ has corrected the Cost Allocation model to capture annual bill counts of 24 for the Large Use class. Table 4: Number of Bills in Cost Allocation Model provides an excerpt of the Number of Bills allocator from the cost allocation model and Table 5: Revenue to Cost Ratios and Revenue Requirement by Class provides the updated revenue requirement by class.

[9] OEB Staff Submission on Draft Rate Order, page 5
[10] VECC Submission on Draft Rate Order, page 2

Table 4: Number of Bills in Cost Allocation Model

			1	2	3	5	6
	ID	Total	Residential	GS <50	GS> 50- 999 kW	GS> 1,000 - 4,999 kW	Large Use
Billing Data							
Bad Debt 3 Year Historical Average	BDHA	$307,183	$166,274	$29,211	$23,631	$88,067	$0
Late Payment 3 Year Historical Average	LPHA	$191,652	$ 141,180.50	$ 26,766.31	$ 21,130.71	$ 2,003.99	$ 309.00
Number of Bills	CNB	793,061	704,127	77,410	9,617	360	24

Table 5: Revenue to Cost Ratios and Revenue Requirement by Class

Class	Revenue to Cost Ratios from 2019 Cost Allocation Model - Line 75 from O1 in CA	Proposed Revenue to Cost Ratio	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue
Residential	85.13%	91.75%	20,937,228	1,360,871	19,576,357
GS < 50 kW	107.56%	107.56%	4,481,397	222,987	4,258,410
GS >50 to 999 Kw	136.08%	120.00%	6,984,708	246,555	6,738,152
GS >1000 to 4999 kW	108.19%	108.19%	2,161,063	87,083	2,073,980
Large Use	158.50%	115.00%	806,114	39,037	767,077
Street Lighting	151.05%	120.00%	595,033	56,586	538,446
Unmetered and Scattered	89.92%	91.75%	71,996	4,557	67,440
Sentinel Lighting	69.94%	91.75%	21,454	1,334	20,119
Embedded Distributor - HON, CND	121.42%	120.00%	52,093	630	51,463
Embedded Distributor - WNH	145.50%	120.00%	189,484	1,665	187,819
Embedded Distributor - HON 1	403.04%	120.00%	35,446	351	35,096
Embedded Distributor - BPI	44.78%	80.00%	10,279	200	10,078
Embedded Distributor - HON 2	168.62%	120.00%	3,574	224	3,350
TOTAL			**36,349,867**	**2,022,079**	**34,327,788**

3. Revenue Requirement

Background

Energy+ and the supporting parties reached a settlement on the 2019 Test Year Revenue Requirement.[11]

[11] Settlement Proposal, Page 24

Comments received on Revenue Requirement

a) VECC noted that the Service Revenue Requirement and, more specifically, the Cost of Power used in the calculation of Working Capital is the same in both the Settlement Proposal and the DRO, despite the forecast purchased power for 2019 decreasing from 1,640,828,035 kWh to 1,623,893,807 kWh. VECC expected that there would be a decrease in Rate Base and a related decrease in the Service Revenue Requirement as a result.[12]

Energy+ Response

Originally, Energy+ did not revise the Service Revenue Requirement in the Draft Rate Order submission based on its understanding that the Settlement Agreement provided for an approved Revenue Requirement.

In response to VECC's concern, in Table 10: Revenue Requirement Impact of Load Forecast Changes, Energy+ has calculated a reduction to the Revenue Requirement of approximately $6,000 as a result of the change in the load forecast. Energy+ submits that this amount is very small and would have a negligible impact on the overall rates to customers. It is well below the Energy+ materiality threshold for this application. However, to make the suggested update would involve a disproportionate amount of staff effort to update the various models and evidence underlying the Final Decision. For this reason, Energy+ submits that due to the immateriality of the impact that no changes to the revenue requirement need to be made as a result of load forecast changes.

Table 10: Revenue Requirement Impact of Load Forecast Changes

Cost of Power Impact	$	(1,303,190)
Working Capital Allowance Rate		7.5%
Working Capital Allowance	$	(97,739)
Regulated Rate of Return		6.2%
Revenue Requirement Impact	$	(6,011)

[12] VECC Submission on Draft Rate Order, page 3

4. Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") Disposition

Background

Energy+ proposes to dispose of a total Lost Revenue Adjustment Mechanism Variance Account debit balance of $1,566,612 with projected interest amounts up to July 31, 2019. The LRAMVA balance has been allocated by rate class, on a harmonized basis, in Tab 4 of the DVA continuity schedule. The rate riders were determined in Tab 7 of the DVA continuity schedule.

Comments on the LRAMVA Disposition

a) OEB Staff requested that Energy+ clarify whether or not the LRAMVA rate riders based on the harmonized approach are accurate for all rate classes and provide a revised DVA continuity schedule to align with the balances in the LRAMVA workforms, as appropriate.[13]

Energy+ Response

Energy+ has corrected the DVA Continuity Schedule to align the allocation of LRAMVA balances by rate class to the LRAMVA work form models. For disposition purposes the balances allocated to the GS > 50-4999 kW class in the BCP LRAMVA work form have been allocated to the harmonized GS > 50-999 kW and GS > 1000-4999 kW classes.

A summary of the revised LRAMVA balances by class used in the DVA disposition calculation are presented in Table 6: LRAMVA Balances Used for DVA Disposition. The balances in Table 6 reconcile with the LRAMVA Work Forms summarized in Table 7: LRAMVA Principal by Class from LRAMVA Work Form.

Table 8: Rate Rider Calculation for Account 1568 (LRAMVA) provides the computation of the revised rate rider by rate class.

[13] OEB Staff Submission on Draft Rate Order, page 5

Table 6: LRAMVA Balances Used for DVA Disposition

	Energy+ (CND)				Energy+ (BCP)				Energy+			
	LRAMVA	Carrying charges	Projected Interest 2018 / 2019	Total	LRAMVA	Carrying charges	Projected Interest 2018 / 2019	Total	LRAMVA	Carrying charges	Projected Interest 2018	Total
Residential	$ (1,742)	$ (1,625)	$ (4,734)	$ (8,101)	$ 84,249	$ 903	$ 2,978	$ 88,130	$ 82,507	$ (723)	$ (1,755)	$ 80,029
GS<50	$ (17,664)	$ (875)	$ (2,549)	$ (21,088)	$ 96,771	$ 1,093	$ 3,606	$ 101,469	$ 79,107	$ 218	$ 1,057	$ 80,382
GS 50-999	$ 811,147	$ 11,614	$ 33,823	$ 856,584	$ 42,198	$ 419	$ 756	$ 43,373	$ 853,345	$ 12,033	$ 34,579	$ 899,957
GS 1000-4999	$ 85,676	$ 914	$ 2,661	$ 89,251	$ 29,252	$ 291	$ 1,587	$ 31,129	$ 114,928	$ 1,204	$ 4,247	$ 120,380
Large Use	$ 313,315	$ 3,271	$ 9,526	$ 326,111	$ -	$ -	$ -	$ -	$ 313,315	$ 3,271	$ 9,526	$ 326,111
Scattered load	$ (2,374)	$ (37)	$ (108)	$ (2,519)	$ -	$ -	$ -	$ -	$ (2,374)	$ (37)	$ (108)	$ (2,519)
Sentinel lighting	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Street lighting	$ (44,004)	$ (680)	$ (1,980)	$ (46,663)	$ 105,628	$ 769	$ 2,538	$ 108,936	$ 61,625	$ 90	$ 559	$ 62,273
Total	**$ 1,144,356**	**$ 12,580**	**$ 36,638**	**$ 1,193,574**	**$ 358,097**	**$ 3,475**	**$ 11,465**	**$ 373,038**	**$ 1,502,453**	**$ 16,055**	**$ 48,104**	**$ 1,566,612**

Table 7: LRAMVA Principal by Class from LRAMVA Work Form

CND Service Territory

Customer Class	Billing Unit	Principal ($)
Residential	kWh	-$1,742
GS<50 kW	kWh	-$17,664
GS 50 to 999 kW	kW	$811,147
GS 1000 - 4,999	kW	$85,676
Large Use	kW	$313,315
Unmetered Scattered Load	kWh	-$2,374
Street Lighting	kW	-$44,004
Total		**$1,144,356**

Brant Service Territory

Customer Class	Billing Unit	Principal ($)
Residential	kWh	$84,249
GS<50 kW	kWh	$96,771
GS 50 to 4999 kW	kW	$71,450
Large User (GS > 5,000 kW)	kW	$0
Unmetered Scattered Load	kWh	$0
Sentinel Lighting	kW	$0
Street Lighting	kW	$105,628
Total		**$358,097**

Table 8: Revised Rate Rider Calculation for Account 1568 LRAMVA

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Account 1568	Rate Rider over 12 Months	Rate Rider over 5 Months
RESIDENTIAL	kWh	461,453,716	$ 80,029	**$ 0.0002**	**$ 0.0004**
GENERAL SERVICE < 50 KW	kWh	193,967,011	$ 80,382	**$ 0.0004**	**$ 0.0010**
GENERAL SERVICE > 50 TO 999 KW	**kW**	1,564,327	$ 899,957	**$ 0.5753**	**$ 1.3807**
GENERAL SERVICE > 1000 TO 4999 KW	**kW**	552,811	$ 120,379	**$ 0.2178**	**$ 0.5226**
LARGE USER	**kW**	330,833	$ 326,111	**$ 0.9857**	**$ 2.3657**
STREET LIGHTS	**kW**	10,945	$ 62,273	**$ 5.6894**	**$ 13.6545**
SENTINEL LIGHTS	**kW**	343	$ -	**$ -**	**$ -**
UNMETERED LOADS	kWh	2,273,988	$ (2,519)	**$ (0.0011)**	**$ (0.0027)**
EMBEDDED DISTRIBUTOR - WATERLOO NORTH	**kW**	114,657	$ -	**$ -**	**$ -**
EMBEDDED DISTRIBUTOR - HYDRO ONE	**kW**	24,387	$ -	**$ -**	**$ -**
EMBEDDED DISTRIBUTOR - BRANTFORD	**kW**	1,075	$ -	**$ -**	**$ -**
EMBEDDED DISTRIBUTOR - HYDRO ONE #1	**kW**	29,011	$ -	**$ -**	**$ -**
EMBEDDED DISTRIBUTOR - HYDRO ONE #2	**kW**	102,973	$ -	**$ -**	**$ -**
Total			**$ 1,566,612**		

5. Bill Impacts and Rate Mitigation Proposal

Energy+ has updated the Bill Impacts to incorporate the corrections and updates identified in Sections 1 through 4. Table 9: Revised Summary of Bill Impacts provides a summary of the Bill Impacts by Customer Class. Consistent with the DRO, the Summary of Bill Impacts includes the disposition of the Deferral and Variance Accounts ("DVA") over a five-month period and excludes the impact of the Foregone Revenue Rate Rider. The table was prepared on the basis that excluding the Foregone Distribution Rate Rider provides the Customer and Energy+ with a comparison that is consistent with the prior rate year and removes the temporary impact of a delay in the implementation date.[14]

[14] DRO, Page 9, Table 2 and Page 35, Paragraph 86.

Table 9: Revised Summary of Bill Impacts

CND Service Territory	kWh	kW	Distribution (Fixed & Volumetric)				Total Bill (Excluding HST)			
			Current 2018	Proposed 2019	$ Change	% Impact	Current 2018	Proposed 2019	$ Change	% Impact
Residential	750	-	$ 24.83	$ 28.03	$ 3.20	12.9%	$ 96.02	$ 102.17	$ 6.16	6.4%
Residential	313	-	$ 22.80	$ 26.89	$ 4.09	17.9%	$ 52.99	$ 59.19	$ 6.20	11.7%
GS < 50 kW	2,000	-	$ 43.21	$ 46.96	$ 3.75	8.7%	$ 243.70	$ 253.21	$ 9.52	3.9%
GS >50 to 999 kW	20,000	60	$ 368.05	$ 329.40	$ (38.64)	-10.5%	$ 3,415.31	$ 3,500.25	$ 84.94	2.5%
GS >1,000 to 4,999	800,000	2,000	$ 8,341.83	$ 8,492.41	$ 150.58	1.8%	$ 124,738.16	$ 125,075.89	$ 337.73	0.3%
Large Use	6,600,000	16,000	$ 48,858.20	$ 35,656.07	$ (13,202.13)	-27.0%	$ 959,490.65	$ 1,004,210.71	$ 44,720.06	4.7%
Unmetered Scattered Load	100		$ 7.15	$ 7.25	$ 0.10	1.4%	$ 17.39	$ 17.41	$ 0.02	0.1%
Street Lighting	400,000	700	$ 44,773.08	$ 35,427.58	$ (9,345.50)	-20.9%	$ 101,505.50	$ 107,273.22	$ 5,767.72	5.7%
EMB - WNH	-	8,280	$ 15,870.25	$ 13,563.47	$ (2,306.78)	-14.5%	$ 47,845.40	$ 29,614.97	$ (18,230.44)	-38.1%
EMB - HONI	1,382,000	2,574	$ 5,296.14	$ 5,431.65	$ 135.51	2.6%	$ 207,486.91	$ 201,711.19	$ (5,775.72)	-2.8%

Brant Service Territory	kWh	kW	Distribution (Fixed & Volumetric)				Total Bill (Excluding HST)			
			Current 2018	Proposed 2019	$ Change	% Impact	Current 2018	Proposed 2019	$ Change	% Impact
Residential	750	-	$ 28.28	$ 28.03	$ (0.25)	-0.9%	$ 102.93	$ 102.17	$ (0.75)	-0.7%
Residential	357	-	$ 26.19	$ 27.01	$ 0.82	3.1%	$ 63.07	$ 63.52	$ 0.45	0.7%
GS < 50 kW	2,000	-	$ 53.36	$ 46.96	$ (6.40)	-12.0%	$ 262.81	$ 253.21	$ (9.60)	-3.7%
GS >50 to 999 kW Interval <1000	20,000	60	$ 332.76	$ 329.40	$ (3.36)	-1.0%	$ 3,512.04	$ 3,503.01	$ (9.04)	-0.3%
GS >50 to 999 kW	20,000	60	$ 332.76	$ 329.40	$ (3.36)	-1.0%	$ 3,496.48	$ 3,500.25	$ 3.77	0.1%
GS >1,000 to 4,999	800,000	2,000	$ 7,956.38	$ 8,492.41	$ 536.03	6.7%	$ 134,337.28	$ 125,075.89	$ (9,261.39)	-6.9%
Unmetered Scattered Load	100	-	$ 4.37	$ 7.25	$ 2.88	65.9%	$ 14.84	$ 17.41	$ 2.57	17.3%
Sentinel Lighting	10,000	29	$ 1,227.30	$ 1,694.42	$ 467.12	38.1%	$ 2,378.60	$ 2,989.42	$ 610.82	25.7%
Street Lighting	600,000	176	$ 12,373.13	$ 8,250.61	$ (4,122.52)	-33.3%	$ 104,532.03	$ 96,015.21	$ (8,516.82)	-8.1%
EMB - BPI	50,000	27	$ 203.08	$ 253.14	$ 50.06	24.6%	$ 7,849.35	$ 7,272.85	$ (576.50)	-7.3%
EMB - HON #1	1,300,000	2,340	$ 9,292.48	$ 2,833.10	$ (6,459.38)	-69.5%	$ 212,927.34	$ 187,680.38	$ (25,246.95)	-11.9%
EMB - HON #2	1,990,000	4,050	$ 96.98	$ 69.79	$ (27.19)	-28.0%	$ 276,731.57	$ 266,444.39	$ (10,287.18)	-3.7%

In the Draft Rate Order, the total bill impact for a typical residential customer in the Cambridge Service Territory was identified at that time as an increase of 6.4% and a low volume residential customer of 11.7%. The total bill impact for a typical residential customer in the Brant Service Territory was identified as a decrease of 0.7% and an increase of 0.7% for a low volume residential customer. The Bill Impacts for the Residential customers has not changed as a result of the revisions made to reflect the corrections incorporated in this response.

The principal driver of this greater than ten per cent impact on low volume residential consumers was the Board's decision to change the cost allocation for the Large User rate class, which resulted in more costs being shifted to the residential rate class. The total bill impacts for low volume residential customers was acknowledged by the Board in its Decision to be in the range of 12.2% to 13.3% for all scenarios that have been explored in this proceeding.[15]

[15] Decision and Order, June 13, 2019, Page. 29.

Comments on the Bill Impacts and Rate Mitigation

a) OEB Staff commented that including the foregone revenue rider, the total bill impact for a typical residential customer would be a 10.4% increase, and for a low volume residential customer would be a 21.3% increase.

   OEB Staff acknowledged that recovering foregone revenue over 5 months would avoid multiple implementations in 2020 and be easier for customers to understand the changes.

   OEB Staff noted that per the Chapter 2 of the Filing Requirements, a distributor must file a mitigation plan if total bill increases for any customer class exceed 10%. OEB Staff requested Energy+ propose a mitigation plan for the OEB's consideration.

   OEB Staff estimated that recovering the foregone revenue over 17 months would address the quanta of the impacts for all classes except low volume residential class and would address the timing of rate changes. OEB Staff requested that Energy+ provide the length of time required to lower the bill impact for a low volume residential customer under 10%.[16]

b) VECC disagreed with the approach of excluding the forgone revenue rate rider when determining the bill impacts. VECC noted that the foregone revenue rate rider is one of the elements that will appear on customers' bills as of August 1, 2019 and should be included in the bill impact calculations.[17]

   VECC supported OEB Staff's request that Energy+ explore mitigation options that would reduce the total bill impact for Residential customers. VECC suggested that Energy+ should consider extending the Residential class' transition to a fully fixed service charge by an additional year to address the impact on low use Residential customers.[18]

[16] OEB Staff Submission on Draft Rate Order, page 7
[17] VECC Submission on Draft Rate Order, page 3
[18] VECC Submission on Draft Rate Order, pages 3 to 4

Energy+ Response

In response to OEB Staff's request that Energy+ propose a mitigation plan to alleviate the rate impacts on the residential customer class arising from this Application, Energy+ notes that it has already done this. The Ontario Energy Board in its Decision and Order approved Energy+'s proposal to address rate mitigation for the residential class of customers.

Specifically:

> "The total bill impacts for low volume residential customers are in the range of 12.2% to 13.3% for all scenarios that have been explored in this proceeding.[118] Energy+ proposed to mitigate the total bill impact on low volume residential customers by deferring the transition to a fully fixed monthly service charge for the Residential class by one additional year to reduce the bill impact to less than 10%.[119]
>
> OEB staff, CCC and VECC supported Energy+'s mitigation proposal.
>
> **Findings**
>
> The OEB finds that Energy+'s residential rate mitigation proposal is reasonable and directs its implementation."[19]

As a direct result of the Board's Decision to approve direct cost allocation to the Large Use class, a significant amount of Revenue Requirement has shifted to the Residential class. The expected bill impacts, as a result of this Decision, were understood by the parties and the Board.[20] The total distribution rates for the Large Use class, based on consumption of 16,000 kW, decreased by 26.7%, while the typical residential class increased by 12.9% in the CND Service Territory. [21]

The Board, taking into consideration the expected rate increases explored during the proceeding, could have, as part of its Decision, directed Energy+ to mitigate the rate increase to the Residential customer class by directing a transition of the implementation of direct cost allocation to the Large

[19] Decision at page 29.
[20] Oral Hearing, Exhibit K1-6_SEC_Appendix A Bill Impact Scenarios_20190307
[21] Draft Rate Order, Table 2, Page 9.

User class over a period of time. Energy+ submits that this mitigation option is one that only the Board is in a position to consider and direct.

Energy+ has strictly followed the Board's Decision with respect to rate mitigation for the Residential customer class and submits that no further rate mitigation is required.

Energy+ notes that the total bill impact, excluding the foregone revenue rate rider, is in fact below 10% for the Residential rate class.

Transition to Fixed Distribution Rate for Residential Customers

Energy+ received approval to transition to a fully fixed rate over a four-year period, commencing with May 1, 2016 rates.[22] For Energy+, 2019 represented the fourth and final year of the transition to a fully fixed monthly service charge in accordance with Board policy[23]. As part of this proceeding, and as approved by the Board in its Decision, Energy+ has already extended the transition period one additional year, which would represent a five-year transition period.

As such, Energy+ does not consider the extension of an additional year for the transition period to a fully fixed distribution rate for Residential Customers to be an option available to it at this stage, as doing so would be contrary to the Board's Decision.

Energy+ would also note that extending the transition to a fully fixed rate has a diminishing effect the further it is extended. As illustrated in Table 10: Effect of Extending Transition to Residential Fixed Rate, extending the transition out as far as 15 years does not reduce the total bill impacts for the low volume residential customers below 10%.

Finally, as illustrated in Table 11: Effect of Extending Transition to Residential Fixed Rate, extending the transition to fully fixed rates also has an adverse effect on the bill impacts to the average Residential customers.

[22] EB-2018-0028, Exhibit 8, Page 7 of 157.
[23] Report of the Board: A New Rate Design for Electricity Residential Customers (EB-2012-0410)

Table 10: Effect of Extending Transition to Residential Fixed Rate on Low Volume consumers

Residential Low Vol (313 kWh)	Fixed Rate	Variable Rate	Distribution (Fixed & Volumetric)				Total Bill			
			Current 2018	Proposed 2019	$ Change	% Impact	Current 2018	Proposed 2019	$ Change	% Impact
Fully Fixed	$ 27.80	$ -	$ 22.80	$ 27.80	$ 5.00	21.9%	$ 52.99	$ 60.10	$ 7.11	13.4%
1 Year Transition	$ 26.08	$ 0.0026	$ 22.80	$ 26.89	$ 4.09	17.9%	$ 52.99	$ 59.19	$ 6.20	11.7%
2 Year Transition	$ 25.50	$ 0.0035	$ 22.80	$ 26.60	$ 3.79	16.6%	$ 52.99	$ 58.89	$ 5.91	11.1%
3 Year Transition	$ 25.22	$ 0.0039	$ 22.80	$ 26.44	$ 3.64	16.0%	$ 52.99	$ 58.74	$ 5.75	10.9%
4 Year Transition	$ 25.05	$ 0.0042	$ 22.80	$ 26.36	$ 3.56	15.6%	$ 52.99	$ 58.66	$ 5.67	10.7%
5 Year Transition	$ 24.93	$ 0.0044	$ 22.80	$ 26.31	$ 3.50	15.4%	$ 52.99	$ 58.61	$ 5.62	10.6%
6 Year Transition	$ 24.85	$ 0.0045	$ 22.80	$ 26.26	$ 3.46	15.2%	$ 52.99	$ 58.56	$ 5.57	10.5%
7 Year Transition	$ 24.79	$ 0.0046	$ 22.80	$ 26.23	$ 3.43	15.0%	$ 52.99	$ 58.53	$ 5.54	10.5%
8 Year Transition	$ 24.74	$ 0.0047	$ 22.80	$ 26.21	$ 3.41	14.9%	$ 52.99	$ 58.51	$ 5.52	10.4%
9 Year Transition	$ 24.70	$ 0.0047	$ 22.80	$ 26.17	$ 3.37	14.8%	$ 52.99	$ 58.47	$ 5.48	10.3%
10 Year Transition	$ 24.67	$ 0.0048	$ 22.80	$ 26.17	$ 3.37	14.8%	$ 52.99	$ 58.47	$ 5.48	10.3%
11 Year Transition	$ 24.64	$ 0.0048	$ 22.80	$ 26.14	$ 3.34	14.6%	$ 52.99	$ 58.44	$ 5.45	10.3%
12 Year Transition	$ 24.62	$ 0.0049	$ 22.80	$ 26.15	$ 3.35	14.7%	$ 52.99	$ 58.45	$ 5.46	10.3%
13 Year Transition	$ 24.60	$ 0.0049	$ 22.80	$ 26.13	$ 3.33	14.6%	$ 52.99	$ 58.43	$ 5.44	10.3%
14 Year Transition	$ 24.59	$ 0.0049	$ 22.80	$ 26.12	$ 3.32	14.6%	$ 52.99	$ 58.42	$ 5.43	10.3%
15 Year Transition	$ 24.57	$ 0.0049	$ 22.80	$ 26.10	$ 3.30	14.5%	$ 52.99	$ 58.40	$ 5.41	10.2%

Table 11: Effect of Extending Transition to Residential Fixed Rate on Average Volume consumers

Residential Average Vol (750 kWh)	Fixed Rate	Variable Rate	Distribution (Fixed & Volumetric)				Total Bill			
			Current 2018	Proposed 2019	$ Change	% Impact	Current 2018	Proposed 2019	$ Change	% Impact
Fully Fixed	$ 27.80	$ -	$ 22.80	$ 27.80	$ 5.00	21.9%	$ 96.02	$ 101.94	$ 5.92	6.2%
1 Year Transition	$ 26.08	$ 0.0026	$ 22.80	$ 28.03	$ 5.23	22.9%	$ 96.02	$ 102.17	$ 6.15	6.4%
2 Year Transition	$ 25.50	$ 0.0035	$ 22.80	$ 28.13	$ 5.32	23.3%	$ 96.02	$ 102.27	$ 6.25	6.5%
3 Year Transition	$ 25.22	$ 0.0039	$ 22.80	$ 28.15	$ 5.34	23.4%	$ 96.02	$ 102.29	$ 6.27	6.5%
4 Year Transition	$ 25.05	$ 0.0042	$ 22.80	$ 28.20	$ 5.40	23.7%	$ 96.02	$ 102.34	$ 6.32	6.6%
5 Year Transition	$ 24.93	$ 0.0044	$ 22.80	$ 28.23	$ 5.43	23.8%	$ 96.02	$ 102.37	$ 6.35	6.6%
6 Year Transition	$ 24.85	$ 0.0045	$ 22.80	$ 28.23	$ 5.42	23.8%	$ 96.02	$ 102.37	$ 6.35	6.6%
7 Year Transition	$ 24.79	$ 0.0046	$ 22.80	$ 28.24	$ 5.44	23.8%	$ 96.02	$ 102.38	$ 6.36	6.6%
8 Year Transition	$ 24.74	$ 0.0047	$ 22.80	$ 28.27	$ 5.46	24.0%	$ 96.02	$ 102.41	$ 6.39	6.6%
9 Year Transition	$ 24.70	$ 0.0047	$ 22.80	$ 28.23	$ 5.42	23.8%	$ 96.02	$ 102.37	$ 6.35	6.6%
10 Year Transition	$ 24.67	$ 0.0048	$ 22.80	$ 28.27	$ 5.47	24.0%	$ 96.02	$ 102.41	$ 6.39	6.7%
11 Year Transition	$ 24.64	$ 0.0048	$ 22.80	$ 28.24	$ 5.44	23.8%	$ 96.02	$ 102.38	$ 6.36	6.6%
12 Year Transition	$ 24.62	$ 0.0049	$ 22.80	$ 28.30	$ 5.49	24.1%	$ 96.02	$ 102.44	$ 6.42	6.7%
13 Year Transition	$ 24.60	$ 0.0049	$ 22.80	$ 28.28	$ 5.47	24.0%	$ 96.02	$ 102.42	$ 6.40	6.7%
14 Year Transition	$ 24.59	$ 0.0049	$ 22.80	$ 28.27	$ 5.46	24.0%	$ 96.02	$ 102.41	$ 6.39	6.6%
15 Year Transition	$ 24.57	$ 0.0049	$ 22.80	$ 28.25	$ 5.44	23.9%	$ 96.02	$ 102.39	$ 6.36	6.6%

Impact of Delays to Foregone Revenue Rate Rider

Energy+ submits that deferring the recovery of the Foregone Revenue Rate Rider by an additional 12 months, for a total recovery period of 17 months, as was recommended by OEB staff, would be prejudicial to the financial results and cash flow position of Energy+ while providing no material benefit to customers.

Specifically, the principal benefit of OEB Staff's approach would be to reduce the total bill impact including the foregone revenue rate rider for residential consumers from the current 10.4% to below 10%. More notably, OEB Staff's recommendation does not reduce the total bill impact (including the foregone revenue rate rider) for low volume residential consumers to below 10%. Energy+ has demonstrated in

Table 10 above that the total bill impacts for low volume residential cannot be mitigated below 10% excluding the forgone revenue rate rider without altering the revenue requirement allocated to the residential class. As a result, the inclusion of the forgone rate rider, regardless of the disposition period, will not reduce total bill impacts below 10% for low volume residential customers.

Energy+ submits that the prejudicial impacts to Energy+, as described below, do not merit this intervention.

Energy+ has operated throughout 2019 on the basis that it would ultimately receive the Board's approved Revenue Requirement and resulting cash flow in 2019. The foregone revenue amount of $596,225 is material to the financial results and cash flow position of Energy+.

Energy+ does not agree with OEB Staff's suggestion of extending the period for recovering forgone revenue to 17 months. Such a suggestion would result in Energy+ deferring the collection of $419,003, or more than 70%, of the forgone revenue amount beyond the 2019 fiscal year. With a revenue deficiency of $1,022,100, a deferral of this magnitude represents an under recovery in 2019 of over 40%. This would have an adverse effect on the financial results and cash flow of Energy+ for the 2019 fiscal year.

In addition, Energy+ submits that the disposition of the foregone distribution revenue rate rider over a five-month period, consistent with the Deferral and Variance Account dispositions, will provide benefits and/or be justifiable to Energy+ customers as follows:

- Disposition over a period that is consistent with the Deferral and Variance Accounts allows for a much less complex tariff sheet and facilitates energy literacy and ease of understanding by customers;
- Through extensive customer engagement activities, customers were informed in 2018 that distribution rates were expected to change effective January 1, 2019.
- Recovering forgone revenue over five months has the same annual impact to customer bills as a January 1, 2019 implementation date.
- Reduces the potential for customer confusion with respect to the estimated bill impacts at the time of implementing the 2020 distribution rates on January 1, 2020. The actual monthly bill impacts based on year over year, excluding the foregone revenue rate rider, will represent the actual comparison of the bill impact resulting from new distribution rates.

If, in rendering its Final Decision, the Board determines that further mitigation is required, Energy+ would ask the Board to consider the disposition of the forgone revenue rate rider over a period of 9 months as an alternative to OEB Staff's recommendation of 17 months.

This alternative would have the effect of mitigating the total bill impact for the average Residential customer to 8.6% from 10.4% under the five-month disposition proposal. As indicated previously, the total bill impacts for low volume residential customers cannot be mitigated below 10%, however, this alternative would result in lowering the total bill impact to 17.0% from 21.3%.

Although this alternative does not achieve the desired objective of reducing customer confusion as a result of multiple rate changes or improved efficiencies, the foregone distribution rate rider end date of April 30, 2020 would coincide with any billing changes that may be required with respect to Time of Use commodity rates on May 1st.

A comparison of the forgone rate rider disposition scenarios is presented in Table 12: Total Bill Impacts with Forgone Revenue Rate Rider Scenarios.

Table 12: Total Bill Impacts with Forgone Revenue Rate Rider Scenarios

CND Service Territory	kWh	kW	Total Bill + Forgone Over 5 Months				Total Bill + Forgone Over 9 Months			
			Current 2018	Proposed 2019	$ Change	% Impact	Current 2018	Proposed 2019	$ Change	% Impact
Residential (Transition to Fixed Extended 1 Year)	750	-	$ 96.02	$ 105.97	$ 9.95	10.4%	$ 96.02	$ 104.28	$ 8.27	8.6%
Residential (Transition to Fixed Extended 1 Year)	313	-	$ 52.99	$ 64.26	$ 11.27	21.3%	$ 52.99	$ 62.01	$ 9.02	17.0%
GS < 50 kW	2,000	-	$ 243.70	$ 255.17	$ 11.47	4.7%	$ 243.70	$ 254.30	$ 10.60	4.4%
GS >50 to 999 kW	20,000	60	$ 3,415.31	$ 3,452.77	$ 37.46	1.1%	$ 3,415.31	$ 3,473.87	$ 58.56	1.7%
GS >1,000 to 4,999	800,000	2,000	$124,738.16	$ 125,388.92	$ 650.76	0.5%	$124,738.16	$ 125,249.79	$ 511.63	0.4%
Large Use	6,600,000	16,000	$959,490.65	$ 985,727.60	$ 26,236.95	2.7%	$959,490.65	$ 993,942.32	$ 34,451.67	3.6%
Unmetered Scattered Load	100		$ 17.39	$ 17.92	$ 0.53	3.0%	$ 17.39	$ 17.69	$ 0.30	1.7%
Street Lighting	400,000	700	$101,505.50	$ 103,556.74	$ 2,051.24	2.0%	$101,505.50	$ 105,208.51	$ 3,703.01	3.6%
EMB - WNH	-	8,280	$ 47,845.40	$ 30,059.89	$ (17,785.51)	-37.2%	$ 47,845.40	$ 29,862.15	$ (17,983.26)	-37.6%
EMB - HONI	1,382,000	2,574	$207,486.91	$ 200,659.32	$ (6,827.58)	-3.3%	$207,486.91	$ 201,126.82	$ (6,360.09)	-3.1%

Brant Service Territory	kWh	kW	Total Bill + Forgone Over 5 Months				Total Bill + Forgone Over 9 Months			
			Current 2018	Proposed 2019	$ Change	% Impact	Current 2018	Proposed 2019	$ Change	% Impact
Residential (Transition to Fixed Extended 1 Year)	750	-	$ 102.93	$ 105.97	$ 3.04	3.0%	$ 102.93	$ 104.28	$ 1.35	1.3%
Residential (Transition to Fixed Extended 1 Year)	357	-	$ 63.07	$ 68.46	$ 5.39	8.5%	$ 63.07	$ 66.26	$ 3.19	5.1%
GS < 50 kW	2,000	-	$ 262.81	$ 255.17	$ (7.64)	-2.9%	$ 262.81	$ 254.30	$ (8.51)	-3.2%
GS >50 to 999 kW Interval <1000	20,000	60	$ 3,512.04	$ 3,455.52	$ (56.52)	-1.6%	$ 3,512.04	$ 3,476.63	$ (35.42)	-1.0%
GS >50 to 999 kW	20,000	60	$ 3,496.48	$ 3,452.77	$ (43.71)	-1.3%	$ 3,496.48	$ 3,473.87	$ (22.61)	-0.6%
GS >1,000 to 4,999	800,000	2,000	$134,337.28	$ 125,388.92	$ (8,948.36)	-6.7%	$134,337.28	$ 125,249.79	$ (9,087.48)	-6.8%
Unmetered Scattered Load	100	-	$ 14.84	$ 17.92	$ 3.08	20.8%	$ 14.84	$ 17.69	$ 2.85	19.2%
Sentinel Lighting	10,000	29	$ 2,378.60	$ 3,461.86	$ 1,083.26	45.5%	$ 2,378.60	$ 3,251.89	$ 873.29	36.7%
Street Lighting	600,000	176	$104,532.03	$ 95,080.28	$ (9,451.75)	-9.0%	$104,532.03	$ 95,495.81	$ (9,036.23)	-8.6%
EMB - BPI	50,000	27	$ 7,849.35	$ 7,342.93	$ (506.42)	-6.5%	$ 7,849.35	$ 7,311.79	$ (537.57)	-6.8%
EMB - HON #1	1,300,000	2,340	$212,927.34	$ 178,637.18	$ (34,290.16)	-16.1%	$212,927.34	$ 182,656.38	$ (30,270.96)	-14.2%
EMB - HON #2	1,990,000	4,050	$276,731.57	$ 266,406.33	$ (10,325.24)	-3.7%	$276,731.57	$ 266,423.25	$ (10,308.33)	-3.7%