Question #1

Topic: Retail Settlement Variance Accounts; Clearance of 2016 Year-End Balances

Reference EB-2017-0030 Decision and Rate Order (March 22, 2018)

Preamble Energy+ passes the cost of retail transmission and distribution (together, the **"RT Services")** it receives from Hydro One to its distribution customers, such as [redacted], through OEB-approved Retail Transmission Service Rates **("RTSRs").** RTSRs are adjusted by the OEB annually. The differences in any one year, between the amount that Energy+ is charged by Hydro One for the RT Services and the related amount of revenue that Energy+ collects from its distribution customers are recorded in Accounts 1584 and 1586, for future disposition.

Table 6.3 of the above-noted Reference sets out 2016 actual year-end balances, plus interest, for the Cambridge and North Dumfries Hydro Group 1 accounts. Included in the balance of the Group 1 accounts was a credit balance of $597,725 for Account 1584 (Retail Transmission Network Charge) and a credit balance of $576,569 for Account 1586 (Retail Transmission Connection Charge).

[redacted] would like to understand how the credit balances in Accounts 1584 and 1586 were derived.

Sub-Question:

I. Did the balances in Accounts 1584 and 1586, as set out in Table 6.3, reflect the costs incurred by Energy+ for RT Services provided by Hydro One in 2015? in any other year?

Response:

The variance amounts claimed for disposition in Energy+'s 2018 IRM Application (EB-2017-0030) for RT Services in Accounts 1584 and 1586 included transactions for the years 2015 and 2016. The claim included RT Services charged by the IESO and Hydro One in the years 2015 and 2016.

Sub-Question:

II. If the balances in Accounts 1584 or 1586, as of year-end 2016, included costs incurred by Energy+ in respect of RT Services provided in more than one calendar year, please provide a breakdown of the total credit balance in each account, for each included year.

Response:

The following is a summary of the amounts claimed for disposition by year as provided in Tab 3 Continuity Schedule of the 2018 IRM Model for CND Service Territory (EB-2017-0030):

Summary by Year		2015 Transactions	2016 Transactions	Total	Interest	Total
RSVA - Retail Transmission Network Charge	1584	(350,255)	(240,821)	(591,076)	(6,652)	(597,727)
RSVA - Retail Transmission Connection Charge	1586	(354,401)	(248,497)	(602,898)	26,330	(576,568)

Sub-Question:

III. If the balances in Accounts 1584 or 1586 included costs incurred by Energy+ for years other than 2015, please explain the reasons why.

Response:

As provided in Response to Sub-Question #2, the amounts claimed for disposition include the years 2015 and 2016. The 2015 transactions also included a very minor invoice from Hydro One related to 2014 Long-Term Load Transfer ("LTLT") Customers in the amount of $3,022. An LTLT is a situation in which a customer is within one distributor's service area, but is actually served electricity from a second distributor.

Sub-Question:

IV. What were the reasons that contributed to the variances reflected in the 2016 year-end balances of Account 1584 and 1586? (for example, changes in actual vs. forecast loads, timing differences, changes to UTRs, other?)

Response:

Variances in Account 1584 and 1586 arise as a result of differences between the amounts charged by the IESO and Hydro One with respect to Network and Line and Connection Charges, and the amounts billed to customers using the OEB's Board-Approved Retail Transmission Network and Transmission Connection Charge Rates for Energy+. The OEB's Board-Approved Rates are as determined using the OEB's RTSR Model. Variances arise due to differences in the estimated volumes utilized in the RTSR Model to derive the RTSR rates charged to customers (which are generally based on volumes from the previous year) compared to actual volumes by rate class, as well as any transmission rate changes approved by the OEB for the IESO and Hydro One.

The credit balances claimed in Account 1584 and 1586 (CND Service Territory) as at the end of 2016 were derived as follows:

<u>Account 1584 RTSR Network:</u>

Summary of Network Variance Account - CND Service Territory			
	2015	**2016**	**Total**
Revenue			
Amounts Billed to Customers	$ (11,667,962)	$ (10,989,760)	$ (22,657,723)
Unbilled Revenue Adjustments/Other	$ (47,733)	$ 97,816	$ 50,083
Total Flow Through Revenue	$ (11,715,696)	$ (10,891,944)	$ (22,607,640)
Expenditures			
Amounts paid to IESO	$ 11,068,932	$ 10,420,628	$ 21,489,560
Amounts paid to Hydro One	$ 292,590	$ 228,814	$ 521,404
Amounts paid for LTLT Customers	$ 3,928	$ 1,682	$ 5,609
Total Flow Through Expenditures	$ 11,365,450	$ 10,651,123	$ 22,016,573
Variance Account - Principle	$ (350,246)	$ (240,821)	$ (591,067)

Account 1586 RTSR Connection:

Summary of Connection Variance Account - CND Service Territory			
	2015	**2016**	**Total**
Revenue			
Amounts Billed to Customers	$ (7,556,674)	$ (7,351,100)	$(14,907,775)
Unbilled Revenue Adjustments/Other	$ (27,849)	$ (13,199)	$ (41,048)
Total Flow Through Revenue	$ (7,584,523)	$ (7,364,299)	$(14,948,822)
Expenditures			
Amounts paid to IESO	$ 7,160,335	$ 7,001,924	$ 14,162,259
Amounts paid to Hydro One	$ 68,293	$ 112,702	$ 180,994
Amounts paid for LTLT Customers	$ 1,494	$ 1,177	$ 2,670
Total Flow Through Expenditures	$ 7,230,122	$ 7,115,802	$ 14,345,924
Variance Account - Principle	$ (354,401)	$ (248,497)	$ (602,899)

Question #2

Topic: Variance Accounts 1584 and 1586; 2017 Year-End Balances

References: (a) Energy+ Overview of Cost of Service Rate Application presented to [redacted]; and
(b) Energy+ Responses to [redacted] Follow-Up Questions from [redacted].

Preamble: Reference (a) at p.45, states that Energy+ paid "total charges" of [redacted] to Hydro One in respect of [redacted] generation in 2016 and that this amount was recorded in Retail Transmission variance accounts – presumably Accounts 1584 and/or 1586.

Reference (a), at p. 45, also states that as a result of [redacted] generation – related costs being allocated across all other rate classes, [redacted] allocation is approximately 10% versus 100%. Reference (b), at p. 1, states that Energy+ will seek approval to clear the 2017 year-end balances in Accounts 1584 and 1586 as part of its 2019 Cost of Service Application.

Sub-Question:

I. Please confirm that:

(a) the balances in Accounts 1584 and 1586 that Energy+ will be seeking to clear in its 2019 COS Application, will be the 2017 actual year-end balances in these two accounts; and

(b) that the 2017 year-end balances reflect RT Charges incurred in 2016.

Response:

(a) The amounts being sought for disposition in the 2019 Cost of Service Application for Accounts 1584 and 1586 represent the transactions for 2017, including carrying charges (interest). The actual year-end account balances as at December 31, 2017 include amounts related to variances arising from 2015 and 2016 transactions, which were subsequently approved for disposition as part of the 2018 IRM Application.

Please refer to Table 9-11: Continuity Schedule of Proposed DVA Disposition in Exhibit 9, Pg. 21 which summarizes the year-end balances as at December 31, 2017, the principle and interest dispositions approved as part of the 2018 IRM Application, and the resulting balances being requested for disposition.

(b) The 2017 year-end balances reflect RT charges expensed in 2017. As noted below in response to Question #2, Sub-Question III, the amount of [redacted] was invoiced by the IESO and charged to Energy+ in April 2017 and is therefore included in the 2017 transactions requested for disposition.

Sub-Question:

II. What are the 2017 actual year-end balances in Accounts 1584 and 1586? If final balances are not available, explain the reasons why and provide estimates.

Response:

The following is a summary of the actual Group 1 account balances proposed for disposition as at December 31, 2017, including Accounts 1584 and 1586, as summarized in Exhibit 9, Table 9-12:

Table 9-12: Summary of Group 1 Variance Accounts

USoA	Description	Principle Balance	Interest Balance	Total
GROUP ONE				
1550	Low Voltage	(302,251)	(5,052)	(307,303)
1551	Smart Meter Entity Charge	(16,691)	(266)	(16,957)
1580	RSVA - Wholesale Market Service Charge	(1,671,927)	(19,741)	(1,691,669)
1584	RSVA - Retail Transmission Network Charge	(1,291,130)	(31,338)	(1,322,468)
1586	RSVA - Retail Transmission Connection Charge	(585,538)	(12,443)	(597,981)
1588	RSVA - Power	1,219,725	15,866	1,235,591
1589	RSVA - Power Global Adjustment	313,769	5,559	319,329
1595	Disposition and Recovery/Refund of Regulatory Balances (2014)	(20)	10,854	10,834
1595	Disposition and Recovery/Refund of Regulatory Balances (2015)	772	559	1,330
1595	Disposition and Recovery/Refund of Regulatory Balances (2016)	($157,305)	($3,468)	(160,773)
	Subtotal	**($2,490,595)**	**($39,472)**	**($2,530,067)**

Sub-Question:

III. Is the [redacted] referred to in Reference (a) included in the 2017 actual year-end balance of Accounts 1584 and 1586?

Response:

Yes, Energy+ confirms that the 2016 Transmission Gross Load Adjustment for Embedded Generators is included in the actual 2017 transactions (expenses) that forms part of the above noted variance account 1586 Transmission Connection Charge.

In accordance with the IESO's Guide to On-Line Data Submissions, Section 5.8 Submission of Transmission Service Charges for Embedded Generation, data is required to be submitted within three months of the calendar year. Once verified, the IESO invoices the amount due. The above amount was included in the April 2017 invoice received from the IESO.

Sub-Question:

IV. What are the various sources of variances reflected in the 2017 actual year-end balances in Accounts 1584 and 1586? Please specify what amount is attributable to each source of variance.

Response:

The credit balances claimed in Account 1584 and 1586 (Energy+) as at the end of 2017 were derived as follows:

Account 1584 RTSR Network:

Energy+ - Combined Service Territories	
	2017
Revenue	
Amounts Billed to Customers	$ (12,725,146)
Unbilled Revenue Adjustments/Other	$ (67,319)
Total Flow Through Revenue	$ (12,792,466)
Expenditures	
Amounts paid to IESO	$ 10,726,542
Amounts paid to Hydro One	$ 512,447
Amounts paid to Brantford Power	$ 261,986
Amounts paid for LTLT Customers	$ 361
Total Flow Through Expenditures	$ 11,501,336
Variance Account - Principle	$ (1,291,130)

Account 1586 RTSR Connection:

		2017
Revenue		
Amounts Billed to Customers	$	(8,329,754)
Unbilled Revenue Adjustments/Other	$	(7,771)
Total Flow Through Revenue	$	(8,337,525)
Expenditures		
Amounts paid to IESO, excluding Generation Adjustment	$	6,999,352
Amount paid to IESO - Generation Adjustment	$	260,228
Amounts paid to Hydro One	$	306,612
Amounts paid to Brantford Power	$	185,685
Amounts paid for LTLT Customers	$	110
Total Flow Through Expenditures	$	7,751,987
Variance Account - Principle	$	(585,538)

Sub-Question:

V. Over what period will 2017 year-end balances in Accounts 1584 and 1586 be recovered by way of a Rate Rider? January 1, 2019 to December 31, 2019?

Response:

Energy+ has proposed the disposition of its Group 1 Accounts, including Accounts 1584 and 1586, over a one year period from January 1, 2019 to December 31, 2019. Please refer to Exhibit 9, Section 9.3.

Sub-Question:

VI. Please explain, in detail, how the [redacted] amount was derived; for example:

(a) is it [redacted] multiplied by Energy+'s existing Distribution Volumetric Rate?

(b) the actual difference between RT Service charges billed by Hydro One and RT Services charges recovered by Energy+ from [redacted]?; if so, how is this differential determined?; is it on the basis of a [redacted]-specific invoice that is received after the end of a calendar year based on IESO settlement data?

(c) other?

Response:

In summary, the amount is based on the incremental kW multiplied by the Line Connection and Transformation Charge. The incremental kW is computed based on hourly readings on a monthly basis and is calculated as the Maximum of (Load of Preston TS + Output of the Generation at [redacted]) less the Maximum of the Load at Preston TS. In general terms, this represents the difference between the Gross Monthly Peak (Generator plus Load) less the Peak Load quantities billed by the IESO on a monthly basis.

Energy+ is invoiced by the IESO on a monthly basis for Line Connection and Transformation Connection charges based on the Peak Load (kW). The kW used for the computation by the IESO on a monthly basis exclude the kW by the [redacted] generator. The annual true up with the IESO to include the generator kW is completed in accordance with the IESO's Guide to On-Line Data Submissions, Section 5.8 Submission of Transmission Service Charges for Embedded Generation within three months of the year-end.

The following spreadsheet provides the summary of the computation of the [redacted], which is specific to [redacted]. Based upon this computation, which is prepared by Hydro One and reviewed by Energy+, the IESO invoiced this amount in April 2017. Please refer to response to Question #2, Sub-Question III.

[redacted]

Note:

Max of Channel 1 & 2 is the kW load of the Preston TS. Max of DP (delivery point) is the sum of the kW load of Preston TS plus the Generator kW. All figures are calculated hourly.

[redacted]

Sub-Question:

VII. Please provide a schedule that set out precisely how the 2017 actual year-end balances in each of Accounts 1584 and 1586 will be allocated among rate classes and customers in each such class.

Response:

Energy+ has utilized the OEB's Deferral and Variance Account Workform ("DVA Workform"). Please refer to Exhibit 9, Energy+ DVA Continuity Schedule Tab 5. Allocation of Balances.

In accordance with the DVA Workform, the Account 1584 and 1586 balances for the year ended December 31, 2017 are proposed to be allocated to all customers in all rate classes based on the proportion of Metered kWh for each class. The Metered kWh for each rate class are based on the 2019 Load Forecast. The forecasted Metered kWh is not impacted by the Demand kW used for purposes of the Standby/Capacity charge.

Please refer to Exhibit 3, Table 3-31 Summary of Total Load Forecast, Page 28.

The following table summarizes the allocation of these two accounts:

Table: Allocation of Accounts 1584 and 1586 by Rate Class – Disposition Amounts as at December 31, 2017

		D&V Balance for Disposition	Allocator	RESIDENTIAL	GENERAL SERVICE < 50 KW	GENERAL SERVICE > 50 TO 999 KW	GENERAL SERVICE > 1000 TO 4999 KW	LARGE USER	STREET LIGHTS	SENTINEL LIGHTS	UNMETERED LOADS	EMBEDDED DISTRIBUTOR - WATERLOO NORTH	EMBEDDED DISTRIBUTOR - HYDRO ONE	EMBEDDED DISTRIBUTOR - BRANTFORD	EMBEDDED DISTRIBUTOR - HYDRO ONE #1	EMBEDDED DISTRIBUTOR - HYDRO ONE #2
RSVA - Retail Transmission Network Charge	1584	(1,322,468)	kWh	(361,512)	(151,469)	(390,617)	(201,844)	(112,861)	(4,163)	(99)	(1,764)	(45,069)	(9,777)	(270)	(9,457)	(33,566)
RSVA - Retail Transmission Connection Charge	1586	(597,981)	kWh	(163,465)	(68,490)	(176,625)	(91,268)	(51,033)	(1,883)	(45)	(798)	(20,379)	(4,421)	(122)	(4,276)	(15,178)
Percentage of Allocation																
RSVA - Retail Transmission Network Charge				27.3%	11.5%	29.5%	15.3%	8.5%	0.3%	0.0%	0.1%	3.4%	0.7%	0.0%	0.7%	2.5%
RSVA - Retail Transmission Connection Charge				27.3%	11.5%	29.5%	15.3%	8.5%	0.3%	0.0%	0.1%	3.4%	0.7%	0.0%	0.7%	2.5%

Sub-Question:

VIII. Is it Energy+'s intention to recover the 2017 year-end balances from

(a) by way of a single rate rider applicable to all customers, across all classes;

(b) by way of customer-specific rate riders derived on the basis of a direct casual link between the variance and the customer? And

(c) other?

Response:

Please refer to Response to Question #2, Sub-Question VII.

Please refer to Exhibit 9, Section 9.4.2 with respect to the Disposition of Group 1 Variance Accounts, including Accounts 1584 and 1586. Energy+ has proposed a single variable rate rider based on KWh or kW depending upon the customer class. Exhibit 9, Table 9-23 on Pg. 44 provides the computed rate rider by rate class for the Group 1 Accounts.

Question #3

Topic: Variance Accounts 1584 and 1586; 2018 Balances

Preamble: [redacted] would like to understand the status of unrecovered RT-charges incurred by Energy+ in 2017 (to be reflected in 2018 year-end balances).

Sub-Question:

I. Does Energy+ have an estimate of charges for [redacted] generation-related RT charges for RT Services provided by Hydro One in 2017? If Energy+ cannot provide an estimate, can it provide information on how [redacted] may estimate this amount on its own?

Response:

The 2017 Transmission Gross Load Adjustment for Embedded Generators was submitted in March 2018 and was invoiced in April 2018 by the IESO. The following is a summary of the computation.

[redacted]

Note:

Max of Channel 1 & 2 is the kW load of the Preston TS. Max of DP (delivery point) is the sum of the kW load of Preston TS plus the Generator kW. All figures are calculated hourly.

Question #4

Topic: Hydro One Invoices for RT Charges

Preamble: [redacted] wants to confirm its understanding of what types of invoices Energy+ receives from Hydro One in respect of RT charges which are allocated to [redacted] and when these invoices are received.

Sub-Question:

I. Does Hydro One invoice Energy+ monthly for the RT Services it provides to Energy+ in the previous month?

II. What is the period of time between when Energy+ bills its distribution customers for the cost of RT Services provided in any one month and when Energy+ receives invoices from Hydro One for the provision of these Services in that month?

Response:

Question I:

Energy+ receives monthly invoices from the IESO and Hydro One for Network Service Charges, Line Connection and Transformation Connection charge. As explained in Response to Question #2, Sub-Question VI, the annual true up for the Line Connection and Transformation Connection charges with respect to the [redacted] generation kW is completed by March 31 of the following year, and has been invoiced by the IESO in the month of April.

Question II:

Energy+ bills its distribution customers for the RTSR services on a monthly basis based on the Energy+ RTSR Network and RTSR Connection Rates approved annually by the Ontario Energy Board as part of the Schedule of Rates and Tariffs. Energy+ uses the OEB's prescribed RTSR Model included in the IRM Model or the RTSR Model for Cost of Service filers to determine the RTSR Network and Connection Rates.

Each month, the variance between the amounts billed based on the OEB approved rates and the amounts actually paid to the IESO and Hydro One is determined and accumulated in the RTSR variance accounts.

Please refer to Exhibit 8, Section 8.2 Retail Transmission Service Rates for further information with respect to the computation of the proposed RTSR Rates for 2019.

Sub-Question:

III. Does Energy+ receive a year-end "true-up" invoice in respect of RT Services provided in that year? If so, when does it receive such an invoice?

Response:

Please refer to the Response to Question #2, Sub-Question VI. Please note that the "true up" is in respect of [redacted] generation only and is billed by the IESO, based on a computation prepared by Hydro One and reviewed with Energy+.

Sub-Question:

IV. Does Energy+ receive IESO settlement statements that it uses to allocate RT charges to customers? How does Energy+ use these statements to determine variances that are recorded in Accounts 1584 and 1586?

Response:

Energy+ receives monthly invoices from the IESO and Hydro One for Network Service Charges, Line Connection and Transformation Connection charges. These costs are recorded as a transaction (expenditure) in Accounts 1584 and 1586 based on the charge code on the IESO invoice. As noted previously, the annual true up for the [redacted] generation is included on the IESO invoice and recorded in Account 1586 when charged.

Energy+ invoices its customers on a monthly basis based on the OEB approved RTSR rates. These revenues are recorded as a transaction (revenue) in Accounts 1584 and 1586.

The variance between the actual amounts invoiced by the IESO and Hydro One, and the amounts billed to customers, forms the variance account balance, which is allocated to customers on the prescribed OEB methodology, as described in Response to Question #2, Sub-Question VII.

As [redacted] is billed monthly by Energy+ only on the demand on the distribution system, which excludes the generation, [redacted] is not being invoiced for Line Connection and Transformation Connection charges on the generation portion. As a result, the RTSR variance account as it relates to Line Connection and Transformation Connection charges would contain an expense that has not been billed directly to [redacted].

As the billed quantifies currently do not include the generation (in the absence of gross load billing), the variance account is being allocated across all customer classes, which effectively results in other customers being apportioned the true up adjustment for the Transmission Gross Load Adjustment for Embedded Generators.

Sub-Question:

V. Please provide copies of the monthly and year-end (if applicable) Hydro One invoices and the IESO settlement statements that Energy+ received in 2017 and 2018 in respect of RT Services provided to [redacted], in 2016 and 2017. If invoices for RT Services provided in 2017 have yet to be received, please advise when such invoice(s) are expected to be received.

Response:

As explained in Response to Question #2, Sub-Question VI, and Question #3, Sub-Question I, the true up amounts for RT Services for the [redacted] generation were included in the April 2017 and April 2018 IESO invoices. Energy+ has provided the computation of the amounts as part of the previous responses. The amounts are not specifically listed on the IESO invoice as they are incorporated in the Line Connection and Transformation Connection Line items on the monthly IESO invoice. Energy+ verified that the adjustments were included in the detailed settlement file provided by the IESO for each of the months.

Question #5

Topic: Gross Load Billing Proposal

References: (a) Energy+ Overview of Cost of Service Rate Application presented to [redacted]; and

(b) Energy+ Responses to [redacted] Follow-Up Questions from [redacted].

Preamble:

Energy+ is has advised [redacted] that, in its 2019 COS application, it intends to request the OEB for authorization to bill its LDG customers on the basis of gross load.

Sub-Question:

I. Will Energy+'s proposal seeking OEB authorization to gross load bill its LDG customers eliminate the accumulation of variance amounts associated with the gross versus net billing methodology in respect of [redacted] on a go-forward basis, commencing January 1, 2019?

Response:

Based on Energy+'s proposal for using gross load billing effective January 1, 2019, Energy+ proposes to invoice (charge) the RTSR Connection Rate as approved on the kW demand for [redacted] and other customers with load displacement on a monthly basis, including the load displacement generation kW. Energy+ proposes to directly replicate the Hydro One methodology with regards to embedded generation for UTR rates.

In utilizing the gross load billing methodology, which aligns to the methodology used by the IESO and Hydro One for these charges, Energy+ expects this methodology to result in monthly billings to [redacted], and any other load displacement customer, that more closely aligns the billings to the actual costs incurred and charged by the IESO and Hydro One.

Variances in Account 1584 and 1586 arising from the gross versus net billing methodology should be substantially eliminated, however, variances may still arise as a result of differences in the load estimates utilized to derive the approved RTSR rates, compared to the actual load experienced and billed by the IESO and Hydro One.

Sub-Question:

II. How many customers in Energy+'s new harmonized service territory, other than [redacted], have load displacement generation facilities as of January 1, 2018? Will have load displacement generation facilities as of July 1, 2018? As of December 31, 2018?

Response:

As of January 1, 2018, [redacted] is currently the only load displacement generation facility in Energy+'s new harmonized service territory. Energy+ does have some small "net metered" connections < 10KW which are primarily residential customers.

As of July 1, 2018, it is expected that [redacted] will remain as the only customer with load displacement generation facilities.

By December 31, 2018, Energy+ expects that there will be four customers with load displacement generation facilities, in addition to [redacted].

In 2019, Energy+ may also see an additional three customers implement facilities based on current discussions with customers.

Sub-Question:

III. Please provide a list of such load displacement facilities (without identifying specific customers) and the associated name plate capacity.

Response:

Energy+ expects the following four additional customers/locations to be in place by December 31, 2018:

Location 1: Peak Shaving: 600kW (natural gas)

Location 2: Peak Shaving: 750kW (natural gas)

Location 3: Base Load: 30kW (solar)

Location 4: Base Load: 500kW (solar)

Energy+ is aware of the following additional customers/locations that may be implemented in 2019:

- 600kW unit
- 1.5MW Co-generation
- 500kW unit

Sub-Question:

IV. If the OEB approves a gross load billing methodology as part of Energy+'s 2019 COS application, how will 2017 year-end balances in Accounts 1584 and 1586 be allocated to Energy+ distribution customers:

(a) across all customers, in all classes?

(b) across all customers in certain rate classes?

(c) only to customers in a rate class that has load displacement generation customers?

(d) will the rate rider be class or customer specific?

Response:

Energy+ has utilized the OEB's Deferral and Variance Account Workform ("DVA Workform"). Please refer to Exhibit 9, Energy+ DVA Continuity Schedule Tab 5. Allocation of Balances.

In accordance with the DVA Workform, the Account 1584 and 1586 balances for the year ended December 31, 2017 are proposed to be allocated to all customers in all rate classes (approach (a) as identified above) based on the proportion of Metered kWh for each class. The Metered kWh for each rate class are based on the 2019 Load Forecast. Please refer to Exhibit 3, Table 3-31 Summary of Total Load Forecast, Page 28.

The rate rider for the disposition of Accounts 1584 and 1586 is computed as a single rate rider by rate class for the disposition of all Group 1 variance accounts, excluding Account 1589. Please refer to Exhibit 9, Energy+ DVA Continuity Schedule Tab 6. Rate Rider Calculation for Group 1 Deferral/Variance Account Balances (excluding Global Adj.).

Energy+ notes that the kWh volumes used for disposition of the D&V account does not assume any kWh associated with gross load billing (which would be based on demand kW). Commencing in 2019, if Energy+'s proposal is accepted, the gross load billing methodology will be used to invoice [redacted] the RTSR Connection charges on a prospective basis, and impact the disposition of future year's D&V balances to be disposed.

Sub-Question:

V. Which specific groups of customers or rate classes are pooled for the purpose of calculating and applying the rate riders associated with transmission cost variances?

Response:

All customer rate classes are included for the purpose of calculating the allocation of the D&V account balances related to RTSR Network and Connection variances, as described in Response to Question #2, Question VII. Rate riders are computed for each rate class based on the billing determinants using the 2019 Load Forecast.

Sub-Question:

VI. Provide a schedule that shows how existing transmission cost variances are allocated to various rate classes and to customers with a class for the purpose of the calculation of rate riders and the collection of revenues from customers. Please also show recovery of variance amounts associated with Hydro One gross billing for the [redacted] load separately from amounts associated with other transmission cost variances.

Response:

Response to Question #2, Sub-Question VII provides the allocation of the RTSR Network and RTSR Connection variance account for disposition to the various rate classes.

As provided in Response to Question #5, Sub-Question IV, the 2017 D&V variance accounts are proposed to be disposed of using the OEB's D&V Model. Please refer to Exhibit 9, Energy+ DVA Continuity Schedule Tab 5. Allocation of Balances.

In accordance with the DVA Workform, the Account 1584 and 1586 balances for the year ended December 31, 2017 are proposed to be allocated to all customers in all rate classes based on the proportion of Metered kWh for each class. The Metered kWh for each rate class are based on the 2019 Load Forecast. The forecasted Metered kWh is not impacted by the Demand kW used for purposes of the Standby/Capacity charge.

Energy+ has produced the following table, based on the methodology used in the D&V Model to illustrate the recovery of the variance account associated with the [redacted] load generation kW that were billed by the IESO in 2017 and included in the variance account balance (RTSR Connection):

		D&V Balance for Disposition	Allocator	RESIDENTIAL	GENERAL SERVICE < 50 KW	GENERAL SERVICE > 50 TO 999 KW	GENERAL SERVICE > 1000 TO 4999 KW	LARGE USER	STREET LIGHTS	SENTINEL LIGHTS	UNMETERED LOADS	EMBEDDED DISTRIBUTOR - WATERLOO NORTH	EMBEDDED DISTRIBUTOR - HYDRO ONE	EMBEDDED DISTRIBUTOR - BRANTFORD	EMBEDDED DISTRIBUTOR - HYDRO ONE #1	EMBEDDED DISTRIBUTOR - HYDRO ONE #2	Total
RSVA - Retail Transmission Connection Charge, As Filed	1586	(597,981)	kWh	(163,465)	(68,490)	(176,625)	(91,268)	(51,033)	(1,883)	(45)	(798)	(20,379)	(4,421)	(122)	(4,276)	(15,178)	(597,981)
RSVA - Retail Transmission Connection Charge																	
Excluding IESO Generation Adjustment		(858,209)		(234,602)	(98,295)	(253,489)	(130,986)	(73,241)	(2,702)	(64)	(1,145)	(29,248)	(6,345)	(175)	(6,137)	(21,783)	(858,209)
IESO Generation Adjustment Variance (excl. carrying charges)		260,228		71,136	29,805	76,863	39,718	22,208	819	19	347	8,869	1,924	53	1,861	6,605	260,228
Total		(597,981)		(163,465)	(68,490)	(176,625)	(91,268)	(51,033)	(1,883)	(45)	(798)	(20,379)	(4,421)	(122)	(4,276)	(15,178)	(597,981)
Allocator Percentage - As Filed				27.3%	11.5%	29.5%	15.3%	8.5%	0.3%	0.0%	0.1%	3.4%	0.7%	0.0%	0.7%	2.5%	

Note: Energy+ has not included the carrying charges that would be allocated to the IESO Generation Adjustment variance as it is not considered material for the purpose of this illustration.

Based on the current methodology for the disposition of the D&V accounts, and based on the fact that Energy+ did not have an approved Schedule of Rates and Tariffs that provided for gross load billing in 2017 (and as a result the RTSR Connection variance account includes an expense that was not passed onto customers in the existing RTSR rates), the IESO Generation Adjustment Variance arising from the RTSR Connection charges which include generation, is being allocated across all customers.

Sub-Question:

VII. Starting in 2019, will the transmission costs associated with [redacted] generation be charged monthly, based on an estimate of the Hydro One charges? If so, will there be an annual "true-up"

Response:

Based on Energy+'s proposal for using gross load billing effective January 1, 2019, Energy+ proposes to invoice (charge) the OEB Approved RTSR Transmission Connection Rate (based on the 2019 Cost of Service Application) on the kW demand for [redacted] on a monthly basis, including the load displacement generation kW.

Any variance arising between the amount of the RTSR rates approved in the Application (and therefore charged to customers) and the RTSR costs actually charged by the IESO and Hydro One in 2019 will be included in the D&V variance accounts 1584 and 1586 for future disposition. In utilizing the gross load billing methodology, which aligns to the methodology used by the IESO and Hydro One for these charges, it is expected to result in monthly billings to [redacted] and any other load displacement customer, that more closely aligns the billings to the actual costs incurred and charged by the IESO and Hydro One.

As the RTSR Rate Model that determines the billing rate to customers utilizes an estimated load (based on a historical year), variances arising as a result of volume and rate differences may still occur, however, the current variance that arises as a result of the [redacted] not being billed the RTSR rate on the generation costs will be substantially eliminated by charging [redacted] RTSR Connection on a gross load billing basis, which includes the generation.

Question #6

Topic: Lost Revenue Adjustment Mechanism
Reference:
Preamble:

Energy + Overview of Cost of Service Rate Application

Page 34 of the Reference states that distribution rates for the [redacted] class established in Energy+'s 2014 rebasing, were based on a load forecast prepared in 2013/2014 that did not include the impact of the [redacted] generation facilities that was placed into service in [redacted]. There is an additional note stating that amounts related to the Lost Revenue Adjustment Mechanism ("LRAM") are recorded in "regulatory deferral accounts to be disposed at a future date".

Sub-Question:

I. Please provide a schedule that sets out Energy+'s 2017 year-end LRAM Deferral Account balances, broken out by the year to which each amount relates (if applicable).

Response:

Please refer to Appendix 4-14 for the LRAMVA work form filed with the Application. The following table represents the LRAMVA for the CND Service Territory Only. Currently there are 2 [redacted] customers in the CND Service Territory only

The summary of the LRAMVA, by year, is from Table 1-b of the LRAMVA work form filed with the application (Exhibit 4, Page 496 of 540):

Description	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting	Total
	kWh	kWh	kW	kW	kW	kWh	kW	
2014 Actuals	$103,837.25	$16,927.39	$271,589.19	$42,369.42	$13,503.71	$0.00	$0.00	$448,226.96
2014 Forecast	($192,179.52)	($58,245.74)	($150,268.62)	($48,776.09)	($26,955.13)	($618.59)	($10,336.76)	($487,380.46)
Amount Cleared								
2015 Actuals	$136,497.13	$38,006.05	$344,408.88	$64,538.09	$16,600.74	$0.00	$0.00	$600,050.89
2015 Forecast	($198,844.71)	($60,402.99)	($155,686.19)	($50,453.62)	($28,011.62)	($575.44)	($11,039.66)	($505,014.22)
Amount Cleared								
2016 Actuals	$210,241.17	$64,280.72	$379,101.02	$71,394.64	$197,014.58	$0.00	$0.00	$922,032.14
2016 Forecast	($167,740.51)	($61,697.34)	($158,230.16)	($51,277.16)	($28,469.78)	($585.03)	($11,220.16)	($479,220.13)
Amount Cleared								
2017 Actuals	$185,035.01	$70,586.82	$260,423.91	$66,279.15	$193,369.22	$0.00	$0.00	$775,694.11
2017 Forecast	($118,862.48)	($62,560.24)	($160,867.20)	($52,131.15)	($28,943.26)	($594.62)	($11,407.09)	($435,366.03)
Amount Cleared								
Carrying Charges	($4,950.90)	($3,056.60)	$24,167.13	$1,184.22	$7,578.63	($91.02)	($1,659.36)	$23,172.11
Total LRAMVA Balance	**-$46,968**	**-$56,162**	**$654,638**	**$43,128**	**$315,687**	**-$2,465**	**-$45,663**	**$862,195.37**

Details are in Table 4-d, and 5-a to 5-c of the LRAMVA work form filed with the application. Relevant parts of these tables are as follows:

Table 4-d. 2014 Lost Revenues Work Form

Program	Rate Allocations for LRAMVA							
	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting	Total
Lost Revenue in 2014 from 2011 programs	$20,798.82	$4,435.12	$78,209.46	$11,897.48	$2,707.35	$0.00	$0.00	$118,048.22
Lost Revenue in 2014 from 2012 programs	$14,129.74	$4,772.19	$58,801.90	$9,191.81	$1,843.56	$0.00	$0.00	$88,739.19
Lost Revenue in 2014 from 2013 programs	$22,217.17	$2,543.89	$66,903.45	$10,270.17	$2,189.46	$0.00	$0.00	$104,124.12
Lost Revenue in 2014 from 2014 programs	$46,691.53	$5,176.20	$67,674.39	$11,009.97	$6,763.34	$0.00	$0.00	$137,315.43
Total Lost Revenues in 2014	**$103,837.25**	**$16,927.39**	**$271,589.19**	**$42,369.42**	**$13,503.71**	**$0.00**	**$0.00**	**$448,226.96**
Forecast Lost Revenues in 2014	**$192,179.52**	**$58,245.74**	**$150,268.62**	**$48,776.09**	**$26,955.13**	**$618.59**	**$10,336.76**	**$487,380.46**
LRAMVA in 2014								**-$39,153.49**

Table 5-a. 2015 Lost Revenues Work Form

Program	Rate Allocations for LRAMVA							
	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting	Total
Lost Revenue in 2015 from 2011 programs	$19,964.15	$4,599.38	$81,029.11	$12,306.66	$2,813.47	$0.00	$0.00	$120,712.77
Lost Revenue in 2015 from 2012 programs	$14,546.03	$4,666.34	$58,995.28	$9,195.48	$1,844.63	$0.00	$0.00	$89,247.76
Lost Revenue in 2015 from 2013 programs	$22,753.03	$2,528.79	$69,055.83	$10,581.11	$2,265.64	$0.00	$0.00	$107,184.39
Lost Revenue in 2015 from 2014 programs	$36,464.06	$5,227.82	$70,043.87	$11,376.43	$7,027.86	$0.00	$0.00	$130,140.05
Lost Revenue in 2015 from 2015 programs	$42,769.86	$20,983.72	$65,284.79	$21,078.40	$2,649.15	$0.00	$0.00	$152,765.91
Total Lost Revenues in 2015	**$136,497.13**	**$38,006.05**	**$344,408.88**	**$64,538.09**	**$16,600.74**	**$0.00**	**$0.00**	**$600,050.89**
Forecast Lost Revenues in 2015	**$198,844.71**	**$60,402.99**	**$155,686.19**	**$50,453.62**	**$28,011.62**	**$575.44**	**$11,039.66**	**$505,014.22**
LRAMVA in 2015								**$95,036.67**

Table 5-b. 2016 Lost Revenues Work Form

Program	Rate Allocations for LRAMVA							
	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting	Total
Lost Revenue in 2016 from 2011 programs	$14,227.40	$4,630.20	$82,040.29	$12,507.54	$2,859.49	$0.00	$0.00	$116,264.90
Lost Revenue in 2016 from 2012 programs	$11,345.13	$4,766.33	$59,623.69	$9,345.57	$1,874.80	$0.00	$0.00	$86,955.53
Lost Revenue in 2016 from 2013 programs	$17,610.52	$2,520.92	$70,000.80	$10,716.43	$2,295.89	$0.00	$0.00	$103,144.56
Lost Revenue in 2016 from 2014 programs	$29,121.79	$5,143.64	$71,188.41	$11,562.13	$5,859.97	$0.00	$0.00	$122,875.94
Lost Revenue in 2016 from 2015 programs	$35,719.41	$21,316.64	$66,351.57	$21,252.71	$183,822.47	$0.00	$0.00	$328,462.79
Lost Revenue in 2016 from 2016 programs	$102,216.92	$25,903.00	$29,896.26	$6,010.27	$301.96	$0.00	$0.00	$164,328.41
Total Lost Revenues in 2016	**$210,241.17**	**$64,280.72**	**$379,101.02**	**$71,394.64**	**$197,014.58**	**$0.00**	**$0.00**	**$922,032.14**
Forecast Lost Revenues in 2016	**$167,740.51**	**$61,697.34**	**$158,230.16**	**$51,277.16**	**$28,469.78**	**$585.03**	**$11,220.16**	**$479,220.13**
LRAMVA in 2016								**$442,812.00**

Table 5-c. 2017 Lost Revenues Work Form

Program	Rate Allocations for LRAMVA							
	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting	Total
Lost Revenue in 2017 from 2011 programs	$9,021.45	$1,533.62	$0.00	$0.00	$0.00	$0.00	$0.00	$10,555.06
Lost Revenue in 2017 from 2012 programs	$7,128.16	$2,843.40	$0.00	$0.00	$0.00	$0.00	$0.00	$9,971.56
Lost Revenue in 2017 from 2013 programs	$11,734.03	$1,466.86	$65,887.52	$10,638.56	$2,275.67	$0.00	$0.00	$92,002.64
Lost Revenue in 2017 from 2014 programs	$20,557.31	$3,617.77	$71,759.08	$11,647.95	$5,952.56	$0.00	$0.00	$113,534.67
Lost Revenue in 2017 from 2015 programs	$25,306.53	$20,789.65	$67,124.27	$19,976.14	$184,333.75	$0.00	$0.00	$317,530.34
Lost Revenue in 2017 from 2016 programs	$72,431.86	$25,675.95	$29,333.06	$5,889.12	$295.87	$0.00	$0.00	$133,625.85
Lost Revenue in 2017 from 2017 programs	$38,855.68	$14,659.57	$26,319.98	$18,127.39	$511.36	$0.00	$0.00	$98,473.98
Total Lost Revenues in 2017	**$185,035.01**	**$70,586.82**	**$260,423.91**	**$66,279.15**	**$193,369.22**	**$0.00**	**$0.00**	**$775,694.11**
Forecast Lost Revenues in 2017	**$118,862.48**	**$62,560.24**	**$160,867.20**	**$52,131.15**	**$28,943.26**	**$594.62**	**$11,407.09**	**$435,366.03**
LRAMVA in 2017								**$340,328.08**

Please note that the 2017 values are based on estimated savings; the final verified results are not expected until the end of June 2018. However, the contribution from the [redacted] generation is based on actual 2017 generation.

Sub-Question:

II. Of the amount(s) shown in the schedule provided in response to Question 1 above, what amounts are attributable to [redacted] generation in [redacted]?

Response:

The calculated lost distribution revenues associated with [redacted] generation are as follows:

[redacted]

Notes:

- Average kW per month are net amounts. Gross amounts are from monthly reported generation. Net amounts are gross amounts times the IESO provided net to gross factor for the PSUI program.
- Distribution rates are the average distribution rate in 2017 for the [redacted].

Sub-Question:

III. Are amounts associated with [redacted] generation recorded separately from other variances in actual load, relative to forecast?

Response:

For most programs, lost revenues are based on IESO verified reports of savings by program, assigned to rate classes by project. The lost revenue associated with the [redacted] generation project is allocated to the [redacted] class. The LRAM associated with the [redacted] class is proposed to be disposed of based on a rate rider computed using the estimated kW for that rate class. Energy+ has two [redacted] in the rate class.

Sub-Question:

IV. With respect to amounts recorded in its LRAM Account, what is Energy+'s proposal for the disposition of booked amounts attributable to [redacted] load displacement?

Response:

Please refer to Exhibit 9, Section 9.4.3 Group 2 Accounts with respect to Energy+'s proposal for the disposition of the LRAM Account as at December 31, 2017.

With respect to the disposition of the 2017 LRAMVA balance, Energy+ has utilized the OEB's Deferral/Variance Account Workform ("DVA Workform"). The Rate Rider computation for Account 1568, found at Tab 6 of the DVA Workform, computes the rate rider based on the amount of the LRAMVA claim allocated to the [redacted] class divided by the forecasted 2019 kW units for the [redacted] class (using the 2019 load forecast). The 2019 load forecast for the [redacted] class assumes a monthly peak demand of [redacted] for [redacted], which was the highest peak load for [redacted] in 2016, and is the basis of the proposal for standby capacity, as explained in Exhibit 7.

Based upon the 2019 Load Forecast of 382,038 metered kW (demand), the portion of the LRAMVA claim that is allocated to [redacted], based on the [redacted] capacity for [redacted], is approximately 90% or [redacted] of the total LRAMVA claim related to the [redacted] of [redacted]; with the balance of 10% or [redacted] allocated to the other [redacted].

Question 7

Topic: Standby Rate Design; Determination of Contract Capacity

Preamble: Energy+'s proposed standby rate structure is based on the identification of a "contract capacity" amount for customers with load displacement generation.

Sub-Question:

I. How and by whom will the contract capacity amount for [redacted] be established? Is it simply a reference to the name-plate capacity of the load displacement facility or is it a negotiated number?

Response:

The contract capacity amount will be negotiated between [redacted] and Energy+, based on an agreed upon historical maximum peak load.

As explained in Exhibit 7, Section 7.1.3.8, Energy+ proposed a contract capacity for [redacted] of [redacted], which was the highest monthly Peak Load provided to [redacted] in 2016. The highest Peak Load for [redacted] in 2016 occurred in July 2016.

As part of the customer engagement meeting on January 19, 2018, Energy+ provided [redacted] with the following information:

- Slide 39 – Contracted Peak KW is determined based on an agreed upon historical maximum Peak
- Slide 40 – Application of the Contracted Capacity Charge Method
- Slide 41 - Outlined how the capacity amount was established

As part of that meeting, Energy+ was specifically seeking feedback from [redacted] on its proposal, which included the proposed contract capacity. Energy+ did not receive any specific feedback with respect to the amount of the proposed capacity and in the absence of feedback proceeded with its proposal.

Sub-Question:

II. Does [redacted] have any input into the determination of the contract capacity amount that will be used in calculating standby revenues? Alternatively, will the amount be set by Energy+? If the latter, can [redacted] influence the contract capacity value set by Energy+ through its behaviour? If so, how can [redacted] influence the value of contract capacity amount that is applied by Energy+?

Response:

Energy+ is willing to consider reasonable proposals from [redacted] on how the capacity level should be set as a starting point. The acceptance on such a proposal could include a condition that if the monthly peak load exceeds that level a new capacity level will be established at the new level going forward until the capacity level is reviewed and adjusted based on the peak load of the next actual year.

Sub-Question:

III. In the event that [redacted] had higher demand in a given month than its contract capacity under the proposed rate structure, what charges would apply to the excess demand (i.e. the increment over contract demand)? Would the charge applied be equal to the charge levied per kW of base contract demand? Would any penalty provisions be added? Alternatively, would there be a ratchet mechanism to increase the contract capacity amount going forward?

Response:

As explained in Exhibit 7, Section 7.1.3.8 Pg. 14 of 105, and as also outlined on Slide 40 of the Customer Engagement Presentation provided on January 19, 2018, if the demand in a given month is more than the contract capacity, there is no capacity charge. The total peak load will be charged the volumetric rate for the [redacted] rate class.

Energy+ has not proposed any penalty provisions or ratchet mechanism. Energy+ did propose that on an annual basis it would review the monthly peak loads and after a discussion with the customer possibly adjust the contracted capacity reserve value.

Question 8

Topic: Standby Rate Design

References: (a) Energy+ Overview of Cost of Service Rate Application presented to [redacted]; and

(b) Energy+ Responses to [redacted] Follow-Up Questions from [redacted].

Preamble: Reference 1 at p. 39 states that the "Contracted Capacity methodology is the proposal currently being supported by OEB staff (subject to further consultation)".

Sub-Question:

I. What is the basis for the statement that OEB staff prefers the "Contracted Capacity" methodology? We note that the OEB identified the use of a standby charge based on nameplate generation capacity in a presentation on September 25, 2017. This presentation was given as part of the OEB's consultations on Commercial Industrial Rate Design (see page 19.).

Response:

Energy+ agrees that in a presentation on September 25, 2017, the OEB staff did identify a capacity reserve charge based on the faceplate capacity of the generation. Energy+ also provided this information to [redacted] at a customer meeting on October 18, 2017 (Page 7 of Energy+'s Customer Meeting Presentation).

In its September 25, 2017 presentation, the OEB's consultations on Commercial Industrial Rate Design, page 22 there is a reference to a capacity reserve charge.

As indicated in Exhibit 7, Page 14 of 105, Energy+ understands that its proposed approach is similar to the approach used by Alectra Utilities Corporation (Horizon Utilities Rate Zone) and Entegrus Powerlines Inc.

It is Energy+'s view that the nameplate generation capacity approach versus the contracted capacity approach as proposed is somewhat similar.

Please refer to response to Question #, Sub-Question VIII for the impact of using the name plate rating.

Sub-Question:

II. In its response to Question 4 of [redacted] follow-up questions (Reference (b)), Energy+ noted that the use of the nameplate capacity was not recommended because it would require customers to pay for the entire load based on the name plate value. Has Energy+ given consideration to applying a lower per unit charge to the name plate capacity portion of load on the basis that use of the associated distribution capacity is required on a less frequent basis than capacity used for base or net load? If not, why not?

Response:

As summarized in Response to Question #9, Sub-Question VIII, Energy+ estimates the annual distribution revenue to [redacted], based on using the nameplate capacity, to be [redacted], which compares to [redacted] using the [redacted] capacity methodology.

Energy+ did not consider the specific scenario described. Energy+ considers that costs to provide a standby service are fixed and do not vary with amount of standby service taken or not taken. As a result, Energy+ believes its proposal to use a capacity charge for standby service is the fairest approach to recover the fixed cost associated with the standby service. To have a lower rate for when standby power is not called upon would mean other customers not using the standby service would be paying for it.

Energy+'s approach is consistent with the OEB's views with respect to the new distribution rate design for residential electricity customers (OEB EB-2012-0410), as outlined on Pg. 10 of the OEB's Board Policy "A New Distribution Rate Design for Residential Electricity Customers":

"*A distributor plans and builds its system to be large enough to serve all of its customers when overall demand is at its highest (for example, a very hot day), even if customers only reach that peak occasionally. These are the costs for transformer stations, poles, meters, trucks, wires, computer systems, etc. We call these distribution costs "fixed costs" because they do not increase or decrease with short-term changes in a customer's usage. The OEB has commissioned analysis related to this point as part of the work done on our new electricity rate regulation framework. That work shows that a distributor's long-term costs are driven largely by two factors: the number of customers and the peak demand on the entire distribution system. Further analysis confirms that the main cost driver is the number of customers, followed by the peak demand, and that the total amount of electricity (as opposed to the peak) has less of an impact on long-term costs for distributors*"

Sub-Question:

III. Alternatively, has Energy+ considered a structure in which a lower charge is applied to the name plate capacity during periods when standby power is not called upon, and regular distribution tariffs applied only when standby power is actually required?

Sub-Question:

IV. Similarly, for an approach using Gross Load Billing, has Energy+ considered a structure with one tariff applied to net load, and a lower tariff applied to gross load? If not, why not?

Response:

Energy+ did not specifically consider the approaches identified in Sub-Question III and IV. Please refer to Response to Question #8, Sub-Question II. Energy+ notes that the variance in the annual distribution revenue under the Capacity versus No Capacity is approximately [redacted] (See Response to Question 9, Sub-Question VIII). Energy+ expects that the cost and effort to perform cost allocation and rate design under these scenarios, as well as the implementation and administration of such rate structures, would likely exceed the annual distribution revenue differential.

Question #9

Topic: Estimated Standby Rates

Preamble: Reference (a), at p. 42 provides estimated rates under a number of alternative scenarios for rate design (i.e. capacity charge versus no capacity charge) and capacity usage.

Sub-Question:

I. Why is a range of rates shown under each scenario? What is the cause of uncertainty with respect to rate amounts? Is it uncertainty in the total Energy+ revenue requirement for 2019, in the amount of [redacted] load, or in other factors? Please indicate the sources of the differences between low and high values shown.

Response:

Energy+ included a range of estimated rates under each scenario because at the time of the customer meeting (January 2018), Energy+ had not yet finalized all of the models underlying the rate design, including the load forecast, rate design, including the determination of the fixed versus volumetric split. In January 2018, Energy+ was in the process of updating the load forecast (updating for 2017 actual load), as well as completing the revenue requirement and rate design model. As Energy+ was expecting to receive feedback from its [redacted] customer on its proposal, the rate proposal was not finalized. Energy+ used a high level % increase for the variable rate estimate and $ amount for the fixed rate estimate based on its best judgement at the time. Energy+ has now finalized its rate proposal, which can be found at Exhibit 7, Section 7.1.3.8 and Exhibit 8, Section 8.1.1.6.

Sub-Question:

II. For the different scenarios shown on pages 42 and 43 (e.g. [redacted] and [redacted]), is the total Revenue Requirement allocated to the [redacted] the same, or is there a change in the Revenue Requirement because of differences in the share of overall demand at the utility accounted for by the [redacted] under the different scenarios? If there is a change in costs allocated to the [redacted], how much does the [redacted] Revenue Requirement change between the scenarios? What are the differences between the values of the demand allocators used for the [redacted] among the scenarios?

Response:

Please refer to the Response to Question #9, Sub-Question VI which provides a summary of the Revenue Requirement for the Large Use class under the different scenarios. The change in the annual load (demand allocator) for [redacted] under the scenarios is also provided.

Sub-Question:

III. What is the basis of the capacity scenario of [redacted]? Is it the capacity of the [redacted] feeder line?

Response:

The [redacted] used in the scenario provided to [redacted] was based on an estimated capacity value using a nominal feeder rating of [redacted]. At [redacted], this computes to [redacted] or approximately [redacted] at near unity power factor.

Energy+ used [redacted] as the capacity of each line. A typical power factor for [redacted] load looking at a sample of 2017 bills is [redacted]. This would create a rating of [redacted] to [redacted] during typical operating conditions. The rating varies with temperature and wind speed. As well, the MW/MVA rating varies with supply voltage level. Typically, Preston TS operates higher than [redacted]. The conductor of the 21M24 and 21M30 circuits is 795MCM Aluminum. During contingencies, the conductor could be operated at a load greater than [redacted].

Sub-Question:

IV. We note that in 2016, the maximum gross load of [redacted] was [redacted]. Since this value would be the maximum amount used in any month to bill [redacted] for distribution services in the event that [redacted] had no on-site generation, under what circumstances is a capacity amount of [redacted] likely to be relevant? Does the [redacted] scenario assume an increase in [redacted] load relative to today? Alternatively, does it reflect a potential policy decision to bill [redacted] on the basis of feeder capacity?

Response:

Please refer to the Response to Question #9, Sub-Question III above for the basis of the [redacted]. This level of capacity was provided as an upper range of capacity available to [redacted]

Energy+ notes the following peak loads experienced by [redacted] that are above the maximum gross load of [redacted] in 2016 noted above, and which exclude the load generation that was implemented in December 2015. Based upon historical experience, in the absence of load generation, it is possible that the maximum gross load of [redacted] could reach [redacted] depending upon [redacted]'s future business plans.

2015-10-01	[redacted]
2014-07-01	
2014-10-01	
2014-09-01	
2014-08-01	
2015-08-01	
2013-07-01	
2015-09-01	
2013-08-01	
2012-07-01	
2013-09-01	

Sub-Question:

V. Reference (a) at p. 44 shows distribution rate impacts based on the Capacity charge scenario of [redacted]. Can we assume that this means that the capacity amount of [redacted] is the amount that Energy+ now proposes to apply to [redacted]?

Response:

Energy+ has utilized the [redacted] in the 2019 Cost of Service Application ("Application") submission. Please refer to Exhibit 7, Section 7.1.3.8. Energy+ had requested feedback from [redacted] on the proposed capacity but did not receive such feedback prior to submitting the Application.

Sub-Question:

VI. Please provide supporting calculations for the rates shown on page 42?

Response:

The following table provides the supporting calculation for the proposed 2019 rates shown as the lower range value on page 42 of the presentation dated January 19, 2018. Please refer to the Response to Question #9, Sub-Question #I with respect to the range provided. The 2017 Current Rates were based on Energy+ Schedule of Rates and Tariffs. As noted at the bottom of the presentation on page 42, the 2018 rates were as per Energy+ 2018 IRM Application, which was pending final approval by the Ontario Energy Board (EB-2017-0030).

The annual distribution cost implications for [redacted] are also provided in the last row of the table.

	2019 Rates No Capacity	2019 Rates With [redacted] [redacted] Capacity	2019 Rates With [redacted] [redacted] Capacity
Class Allocated Cost (A)	$ [redacted]	$ [redacted]	$ [redacted]
2018 Rates times 2019 Volumes times 2019 Overall Rate Increase (B)	$ [redacted]	$ [redacted]	$ [redacted]
Allocated Misc Revenue (C)	$ [redacted]	$ [redacted]	$ [redacted]
Total Revenue before Adjustment for Revenue to Cost Ratio (D) = (B) + (C)	$ [redacted]	$ [redacted]	$ [redacted]
Total Revenue before Adjustment for Revenue to Cost Ratio (E) = (D) / (A)	[redacted]	[redacted]	[redacted]
If Revenue to Cost Ratio < 85% or > 115% Adjustment Needed (F)	No Adjustment Needed	No Adjustment Needed	Adjustment Needed
Proposed Revenue to Cost Ratio (G)	[redacted]	[redacted]	[redacted]
Revenue with Adjusted Revenue to Cost Ratio (H) = (A) * (G) - (C)	$ [redacted]	$ [redacted]	$ [redacted]
Current Fixed Component (I)	[redacted]	[redacted]	[redacted]
Current Variable Component (J)	[redacted]	[redacted]	[redacted]
Customers (K)	[redacted]	[redacted]	[redacted]
Annual Load (L)	[redacted]	[redacted]	[redacted]
Monthly Service Charge (M) = (H) *(I) / (K) /12	$ [redacted]	$ [redacted]	$ [redacted]
Volumetric Charge (N) = (H) *(J) / (L)	$ [redacted]	$ [redacted]	$ [redacted]
Annual Distribution Costs	$ [redacted]	$ [redacted]	$ [redacted]

Sub-Question:

VII. Provide an analysis of potential rates, and cost implications for [redacted], using 2017 data rather than 2016 data.

Response:

The following table provides an analysis of potential rates, and the distribution cost implications for [redacted], using 2017 data, including the cost assumptions in the filed Cost of Service Application for Energy+. The [redacted] reflects the peak load required by [redacted] from Energy+ in 2017. This peak load occurred in November 2017. For comparative purposes, Energy+ has updated the other scenarios, including the capacity at [redacted], using the cost assumptions as filed in the Cost of Service Application for Energy+.

	2019 Rates No Capacity	2019 Rates With [redacted] Capacity	2019 Rates With [redacted] Capacity	2019 Rates With [redacted] Capacity
Class Allocated Cost (A)	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
2018 Rates times 2019 Volumes times 2019 Overall Rate Increase (B)	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Allocated Misc Revenue (C)	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Total Revenue before Adjustment for Revenue to Cost Ratio (D) = (B) + (C)	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Total Revenue before Adjustment for Revenue to Cost Ratio (E) = (D) / (A)	[redacted]	[redacted]	[redacted]	[redacted]
If Revenue to Cost Ratio < 85% or > 115% Adjustment Needed (F)	No Adjustment Needed	No Adjustment Needed	No Adjustment Needed	Adjustment Needed
Proposed Revenue to Cost Ratio (G)	[redacted]	[redacted]	[redacted]	[redacted]
Revenue with Adjusted Revenue to Cost Ratio (H) = (A) * (G) - (C)	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Current Fixed Component (I)	[redacted]	[redacted]	[redacted]	[redacted]
Current Variable Component (J)	[redacted]	[redacted]	[redacted]	[redacted]
Customers (K)	[redacted]	[redacted]	[redacted]	[redacted]
Annual Load (L)	[redacted]	[redacted]	[redacted]	[redacted]
Monthly Service Charge (M) = (H) *(I) / (K) /12	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Volumetric Charge (N) = (H) *(J) / (L)	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
Annual Distribution Costs	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]

Sub-Question:

VIII. Provide an analysis of potential rates and cost implications for [redacted], using:

(a) the name plate capacity approach initially proposed by the OEB; and

(b) the gross load billing approach?

Response:

The following table provides an analysis of potential rates, and cost implications for [redacted], under a name plate capacity and gross load billing approach. For comparative purposes, Energy+ has updated the computation for the capacity at [redacted], using the cost assumptions as filed in the Cost of Service Application for Energy+. Energy+ used a name plate rating of [redacted], which is the combined output of two [redacted] Gas Turbine Generators installed at [redacted].

	2019 Rates With [redacted] Capacity	2019 Rates With [redacted] Name Plate Capacity	2019 Rates Gross Load Billing
Class Allocated Cost (A)	$ [redacted]	$ [redacted]	$ [redacted]
2018 Rates times 2019 Volumes times 2019 Overall Rate Increase (B)	$ [redacted]	$ [redacted]	$ [redacted]
Allocated Misc Revenue (C)	$ [redacted]	$ [redacted]	$ [redacted]
Total Revenue before Adjustment for Revenue to Cost Ratio (D) = (B) + (C)	$ [redacted]	$ [redacted]	$ [redacted]
Total Revenue before Adjustment for Revenue to Cost Ratio (E) = (D) / (A)	[redacted]	[redacted]	[redacted]
If Revenue to Cost Ratio < 85% or > 115% Adjustment Needed (F)	No Adjustment Needed	Adjustment Needed	No Adjustment Needed
Proposed Revenue to Cost Ratio (G)	[redacted]	[redacted]	[redacted]
Revenue with Adjusted Revenue to Cost Ratio (H) = (A) * (G) - (C)	$ [redacted]	$ [redacted]	$ [redacted]
Current Fixed Component (I)	[redacted]	[redacted]	[redacted]
Current Variable Component (J)	[redacted]	[redacted]	[redacted]
Customers (K)	[redacted]	[redacted]	[redacted]
Annual Load (L)	[redacted]	[redacted]	[redacted]
Monthly Service Charge (M) = (H) *(I) / (K) /12	$ [redacted]	$ [redacted]	$ [redacted]
Volumetric Charge (N) = (H) *(J) / (L)	$ [redacted]	$ [redacted]	$ [redacted]
Annual Distribution Costs	$ [redacted]	$ [redacted]	$ [redacted]

Question #10

Topic: Dedicated Assets

Preamble: We understand that Energy+ is taking the position that it needs to protect that portion of its revenue stream associated with assets that may have been "stranded" by the installation of load displacement generation facilities at [redacted] and by the resulting loss of [redacted] on the Energy+ system.

Sub-Question:

I. Please provide the following information with respect to assets used exclusively for the supply of electricity to [redacted] (i.e. for those assets that cannot be used in the supply electricity to other Energy+ customers):

- Asset description.
- Asset value, including information on:
- Gross Book Value
- Accumulated Depreciation
- Net Book Value
- Annual Depreciation Expense

Response:

Energy+ is not proposing the Standby/Capacity Charge to protect its revenue stream from stranded assets. Please refer to Energy+ response to Question #10, Sub-Question III with respect to its rationale for the Standby/Capacity Charge.

There are relatively few assets used exclusively for [redacted] since almost all the poles are multi-circuit (two or three 27.6kV circuits with one circuit used to supply [redacted] and other circuit(s) used to supply other customers). The only poles exclusive to [redacted] are located at the Preston TS.

The assets used exclusive to [redacted] would mainly be the [redacted] and associated clamps/brackets/insulators/bolts along with two [redacted] specific loadbreak switches and a few solid blade switches.

Energy+ has recorded the costs of these assets in the Overhead Conductors and Devices asset category on a pooled asset basis and therefore the asset value, net book value, and annual depreciation expense for these exclusive assets is not specifically available.

Sub-Question:

II. Please provide:

(a) gross and net book amounts as at December 31, 2018; and

(b) projected amounts as at December 31, 2019.

Response:

Please refer to the Response to Question#10, Sub-Question I.

Sub-Question:

III. What is the underpinning rationale for Energy+'s proposal for a standby rate:

(a) to compensate Energy+ for assets stranded by the installation of load displacement generation; or

(b) to compensate Energy+ for operating assets in standby mode.

Response:

As outlined in its Customer Meeting presentation in October, 2017, and again in January, 2018, Energy+ advised [redacted] that it was considering the implementation of a Standby Charge for all GS>50 kW and Large User Class customers based upon the following considerations:

- Contracted capacity is “reserved” for customer with load displacement whereby the customer wishes to ensure that the Energy+ infrastructure is in place at all times to provide the contracted peak load at any time.
- Energy+’s operating costs have not and are not expected to materially change due to load displacement;
- Energy+ provides the infrastructure and back up supply when generation is not fully utilized;
- Energy+ continues to invest in its distribution system, and incurs operations, maintenance and administrative costs to operate the distribution system based upon the expected capacity required; and
- Fairness to all customers – Load displacement by any customer, in the absence of a capacity charge, will result in lower distribution revenue to Energy+ and will impact future rate impacts for all customer rate classes (costs will be socialized across other rate classes).

Sub-Question:

IV. Will Energy+ be proposing:

(a) a standby rate?

(b) a separate standby class?

(c) both (a) and (b)?

Response:

As outlined in Exhibit 7, Section 7.1.3.8 Standby Rates, Energy+ has proposed a standby rate for all GS >50 and above classes of customers with load displacement who require Energy+ to provide electricity through the distribution system when the generation is not running.

Energy+ proposes that a contracted capacity reserve value be established for each customer. 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 applicable rate class. If the load taken is less than the contracted capacity reserve value, the difference between that value and the load taken will be charged a Standby rate, which will be equivalent to the distribution volumetric rate for the applicable rate class. If the load taken is equal to or greater than the capacity reserve value, the Standby rate will not be applied.