EB-2018-0028

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application to the Ontario Energy Board by Energy+ Inc. pursuant to Section 78 of the *Ontario Energy Board Act* for approval of its proposed distribution rates and other charges, effective January 1, 2019.

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COMPENDIUM OF THE SCHOOL ENERGY COALITION
(Energy+ Panel)

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Table 9-1: Deferral and Variance Account Balances for Disposition

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)**
GROUP TWO AND OTHER				
1508	Other Regulatory Assets Deferred IFRS Transition Costs	21,407	4,108	25,515
1508	Other Regulatory Assets - Sub-Account - Ontario Clean Energy Benefit Act	(235)	(4)	(239)
1508	Other Regulatory Assets - Sub-Account - Monthly Billing	497,986	13,463	511,449
1508	Other Regulatory Assets - Sub-Account - OEB Cost Assessment	169,609	4,819	174,428
1518	Retail Cost Variance Account - Retail	162,672	(20,046)	142,626
1531	Renewable Generation Connection Capital Deferral Account	5,338	244	5,582
1548	Retail Cost Variance Account - STR	2,120	462	2,582
1555	Smart Meter Capital and Recovery Offset Variance - Stranded Meter (former CND)	94,210	1,781	95,990
1555	Smart Meter Capital and Recovery Offset Variance - Stranded Meter (Brant)	103,473	3,696	107,169
1557	Meter Cost Deferral Account (MIST Meters)	174,275	4,395	178,670
1568	LRAM Variance Account	1,168,925	31,527	1,200,452
1572	Extra-Ordinary Event Costs	(14,229)	8,359	(5,870)
1575	IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1,908,269	-	1,908,269
1576	Accounting Changes Under CGAAP	(2,456,018)	-	(2,456,018)
	Subtotal	**$1,837,802**	**$52,802**	**$1,890,604**
	GRAND TOTAL	**($652,793)**	**$13,330**	**($639,463)**

9.1.3 Reconciliation of Account Balances

Table 9-2 reconciles the deferral and variance account balances from the 2017 RRR filing 2.1.7, to be filed by April 30, 2018, with the Continuity schedule contained in the EDVAR model filed with this Application. The 2017 RRR filing 2.1.7 reconciles to the Energy+ Audited Financial Statements as at December 31, 2017. An explanation for the variances is also provided.

Table 9-15: Costs Incurred to Transition to Monthly Billing

Incremental Monthly Billing Costs	2016	2017	Total
Labour Costs	54,436	80,815	135,251
Postage Costs	39,281	204,323	243,604
Envelopes and Stationery	12,090	62,884	74,974
Consulting Services	18,515	-	18,515
Advertising to Customers	4,586	-	4,586
Other Expenses	3,361	17,696	21,057
Total	$ 132,268	$ 365,718	$ 497,986
Carrying Charges to December 31, 2018			13,463
Balance in Account			$ 511,449

Details of the costs are as follows:

Labour Costs: Energy+ hired additional contract staff to backfill positions that were dedicated to the monthly billing project during its initial implementation. In 2017, Energy+ hired an additional full-time Billing Clerk to support the incremental effort required to produce monthly bills. In 2018, Energy+ will be hiring a full-time Customer Care Representative to replace a contract position that has been utilized to support the incremental work associated with monthly billing. Overtime during the transition period was also required for some existing staff to work on the implementation project. Detailed records were maintained to track the labour costs related to this project.

Postage Costs: Energy+ determined the number of additional bills that adoption of monthly billing generated and applied the relevant postage costs to determine the incremental costs. It should be noted that postal costs have been steadily increasing over the past several years and are expected to continue to do so.

Envelopes and Stationery: Energy+ determined the number of additional bills that resulted from moving to monthly billing and applied the relevant envelopes and stationery costs to determine the incremental costs.

Consulting Services: Energy+ hired external consultants on a limited basis in 2016 to organize and manage certain aspects of the initial stages of the implementation project.

9–SEC-42

INTERROGATORY

Ref: Ex.9, p.28

Please calculate the working capital savings from moving to monthly billing for each of 2016 and 2017.

RESPONSE

Please note that the former BCP was billing customers monthly at the time of the acquisition in 2014. The former CND moved to monthly billing on January 3, 2017. Energy+ has not done a lead lag study or any other analysis to calculate any working capital savings for the former CND in 2017.

In accordance with the Board's June 3, 2015 letter "Allowance for Working Capital for Electricity Distribution Rate Applications", Energy+ has adopted the Board's 7.5% working capital allowance for the 2019 Test Year in this Application. This represents a reduction from Energy+'s current approved working capital allowance rate of 13%.

9–Staff-104

INTERROGATORY

Ref: Exhibit 9, Table 9-20

The applicant is proposing to continue Account 1508, sub-account Monthly Billing and sub-account cost assessment. The applicant is seeking the disposition of both of these account as part of this current application and the rates approved as part of this application will no longer require the need to track amounts in these accounts beyond 2018.

a) Is the applicant able to estimate the remaining amounts to be included in these accounts for 2018?

RESPONSE

Energy+ estimates the remaining amounts to be included in these accounts for 2018 to be $336,345. This amounts comprises of $256,043 for monthly billing[1] and $80,302 for OEB cost assessments.

1 Energy+ has revised its initial 2018 monthly billing estimate of $371,249 to include $115,206 in cash flow benefits.

SUMMARY OF UPDATED EVIDENCE – DVA ACCOUNT 1508 SUB-ACCOUNT MONTHLY BILLING

Energy+ is submitting updated evidence with respect to the balance of DVA Account 1508 Sub-Account Monthly Billing (“Monthly Billing Account”) as at December 31, 2017.

In the OEB’s Decision and Order dated March 17, 2016 (EB-2015-0057), the OEB approved the former Cambridge and North Dumfries Hydro Inc.’s (“CND”) request for an accounting order to establish a new deferral account to record incremental costs directly related to the implementation of monthly billing for disposition at the time of its next rebasing application. As part of the Decision, the OEB noted that “Costs to be recorded will be net of any associated cost reductions resulting from the transition, including efforts towards paperless billing, improvements in cash flow, or reductions in bad debt.”

Energy+ is updating the balance in the Monthly Billing Account as at December 31, 2017 to record the estimated cash flow benefit to Energy+ attributable to the transition to monthly billing for the period October 2016 through to December 31, 2017. Energy+ did not experience a reduction in bad debt expense related to residential customers in 2016 and 2017 and therefore has not made any adjustments for bad debts.

Energy+ has estimated the cash flow benefit resulting from the one-time collection advancement of one month’s billing for CND customers that transitioned to monthly billing. The one month’s billing was determined based on the average monthly gross revenue for residential customers in the CND rate zone in 2016. The cash flow benefit was then computed based on the average monthly billing amount multiplied by the interest rate earned on cash balances for the period October 1, 2016 to December 31, 2016 and the period January 1, 2017 to December 31, 2017.

As Energy+ was in a positive cash flow position prior to the transition to monthly billing, the increased cash inflow as a result of the transition to monthly billing would have generated additional interest income.

The amount of incremental interest income earned has been estimated using historical prescribed DVA interest rates as summarized in the following table.

	2016	2017	Total
One-time Monthly Billing Collection Benefit	6,185,566	6,185,566	
Prescribed DVA Interest Rates	1.10%	1.20%	
Proportion of Year	25%	100%	
Estimated Cash Flow Benefit	17,010	74,227	91,237

The DVA Continuity schedule has been updated to adjust the balances for 2016 and 2017. The updates to the DVA Continuity schedule were made as principal adjustments in the respective years. The adjusting entries will be posted to Energy+'s general ledger in 2018. As the journal entries will appear in Energy+'s general ledger as 2018 transactions, the principal adjustments from 2016 and 2017 will be reversed in 2018.

Energy+ will also record an additional cash flow benefit for the period January 1, 2018 to December 31, 2018 as part of the transactions for the Monthly Billing Account for the year 2018. The request for disposition of the 2018 monthly billing transactions (the incremental costs, net of any associated cost reductions) will form part of a future IRM Application.

The 2019 Tariff Schedule Model has been updated to reflect the change in the proposed rate rider for monthly billing as a result of the change to the account balance as at December 31, 2017.

The updated evidence includes:

- Exhibit 9 – Section 9.3.3 – Pages 27 to 29
- IRR to 9-Staff-104 a)

The following models were previously filed as part of the Settlement Proposal.

- 2019 EnergyPlus DVA Continuity_Schedule_CoS - Consolidated - Settlement.xlsb
- 2019 EnergyPlus Tariff_Schedule_Model-CND - Settlement.xlsx
- 2019 EnergyPlus Tariff_Schedule_Model-BCP - Settlement.xlsx

Sub Account: Monthly Billing

On April 15, 2015 the OEB announced that by the end of 2016, all electricity distributors in Ontario will be required to bill their customers on a monthly basis. In Energy+'s 2016 IRM application (EB-2015-0057), Energy+ (CND) indicated that it would be in a position to begin billing all customers on a monthly basis, beginning January 1, 2017 and requested an accounting order to establish a new deferral account to record the incremental costs associated with moving to the monthly billing method, as the former CND did not include the costs of monthly billing in its last (2014) Cost of Service application. In the OEB Decision and Rate Order for the IRM application (EB-2015-0057), the OEB approved the account as requested by Energy+. The OEB, in the Decision, also indicated that the costs recorded in this account will be subject to a prudency review at the time of Energy+'s next rebasing application, expected for 2019 rates. This Application is the first rebasing application available in which to claim the costs recorded and accumulating in this account.

Customers of the former BCP were billed on a monthly basis prior to the acquisition by the former CND in 2014. As such, incremental costs associated with monthly billing for only those customers in the Energy+ Cambridge and North Dumfries (CND) service territory have and will continue to be recorded in a deferral account up until December 31, 2018.

Energy+ began moving CND customers to monthly billing in November and December 2016 with all customers transitioned by the billing period beginning January 3, 2017.

The total costs recorded in this account are $406,749 as detailed in the Table 9-6 below. Carrying charges totalled $9,597 to December 31, 2018 making the total applied for recovery $416,346. As a note, Energy+ will be applying in its 2020 IRM application for recovery of the 2018 costs incurring regarding this project.

As summarized in Table 9-15, total costs of $406,749 represent costs incurred for the years 2016 and 2017. Energy+ confirms that it has only recorded incremental costs and benefits in this account.

Table 9-15: Costs Incurred to Transition to Monthly Billing

Incremental Monthly Billing Costs	2016	2017	Total
Labour Costs	54,436	80,815	135,251
Postage Costs	39,281	204,323	243,604
Envelopes and Stationery	12,090	62,884	74,974
Consulting Services	18,515	-	18,515
Advertising to Customers	4,586	-	4,586
Other Expenses	3,361	17,696	21,057
Estimated Cash Flow Benefits	(17,010)	(74,227)	(91,237)
Total	$ 115,258	$ 291,491	$ 406,749
Carrying Charges to December 31, 2018			9,597
Balance in Account			**$ 416,346**

Details of the costs are as follows:

Labour Costs: Energy+ hired additional contract staff to backfill positions that were dedicated to the monthly billing project during its initial implementation. In 2017, Energy+ hired an additional full-time Billing Clerk to support the incremental effort required to produce monthly bills. In 2018, Energy+ will be hiring a full-time Customer Care Representative to replace a contract position that has been utilized to support the incremental work associated with monthly billing. Overtime during the transition period was also required for some existing staff to work on the implementation project. Detailed records were maintained to track the labour costs related to this project.

Postage Costs: Energy+ determined the number of additional bills that adoption of monthly billing generated and applied the relevant postage costs to determine the incremental costs. It should be noted that postal costs have been steadily increasing over the past several years and are expected to continue to do so.

Envelopes and Stationery: Energy+ determined the number of additional bills that resulted from moving to monthly billing and applied the relevant envelopes and stationery costs to determine the incremental costs.

Consulting Services: Energy+ hired external consultants on a limited basis in 2016 to organize and manage certain aspects of the initial stages of the implementation project.

Advertising to Customers: Energy+ sent a notification to affected customers to inform them of the changes to the timing of their bills.

Other Expenses: Miscellaneous expenses related to the monthly billing project.

Cash Flow Benefits: Energy+ estimated the incremental interest income that would have occurred from advancing the collection of residential accounts upon adoption of monthly billing. The calculation of the cash flow benefit is outlined in the table below. In the DVA Continuity, these amounts are presented as principal adjustments in 2016 and 2017. These entries will be posted to the general ledger in 2018 and the total amount will be reversed in the 2018 principal adjustments.

Table 9-16: Calculation of Cash Flow Benefits

	2016	2017	Total
One-time Monthly Billing Collection Benefit	6,185,566	6,185,566	
Prescribed DVA Interest Rates	1.10%	1.20%	
Proportion of Year	25%	100%	
Estimated Cash Flow Benefit	17,010	74,227	91,237

Energy+ has continued to promote e-billing to all of its customers to mitigate the impact of increased billing, printing, and postage costs from the implementation of monthly billing. At the end of 2015, prior to the implementation of monthly billing for CND customers, 5,574 customers were enrolled in e-billing. At the end of 2017, 7,409 customers were enrolled. Although this was a 32% increase in two years, the number of customers enrolled in e-billing is still significantly lower than the number of residential and GS> 50kW customers who receive bills on a monthly basis.

SEC 10

Technical Conference Question

P.18

With respect to working capital:

a. Please confirm that the CND working capital that was set in its last cost of service application for 2014 rates was based on a value of 13% of the sum of cost of power and OM&A.

RESPONSE

Energy+ confirms that the CND working capital was set in its last cost of service application for 2014 rates was based on a value of 13% of the sum of cost of power and OM&A.

SEC 10

Technical Conference Question

P.18

With respect to working capital:

b. Please provide the working capital component of CND’s approved 2014 revenue requirement.

RESPONSE

The working capital component of CND’s approved 2014 revenue requirement was $1,489,594.

SEC 10

Technical Conference Question

P.18

With respect to working capital:

c. Please confirm that adjusting the Board's current working capital allowance default value of 7.5% for the difference between monthly and bi-monthly billing results in a change of value of 4.1%. (See attached Excel spreadsheet for the calculation).

RESPONSE

Energy+ does not confirm that the conversion from monthly to bi-monthly billing would result in a change of value of 4.1% to the working capital percentage for Energy+.

Energy+ notes that the spreadsheet provided by SEC is based on the OEB's default value for Working Capital, which was based on an OEB staff review and analysis of eight lead-lag studies provided to the OEB since 2010 and included in the June 3, 2015 Letter of the Board "Allowance for Working Capital for Electricity Distribution Rate Applications". Energy+ has not prepared a lead-lag study, and is therefore not included in the sample of the eight LDCs used by OEB staff.

Energy+ confirms that SEC has computed the change in value of 4.1% by:

i. Computing a "Working Capital Allowance for Bi-Monthly Billing" by taking the OEB Staff Analysis computation and updating to double the service lag variable from the 15.22 to 30.42.

ii. Computing the difference between the default Working Capital allowance analysis prepared by OEB Staff with the computed working capital allowance in (i).

Energy+ would note the following with respect to this methodology, which SEC asks Energy+ to utilize in responding to SEC-10 (d):

- The methodology assumes that all customers have converted from bi-monthly to monthly billing. In the CND service territory, only customers in the Residential and GS<50 rate classes were impacted by the conversion.

- In the June 3, 2015 OEB Letter of the Board, the OEB noted that the reduction of the working capital allowance from 13% to 7.5% was a result of multiple factors including:

  1) The substantial completion of the smart meter rollout and advanced metering infrastructure, which reduces aggregate meter reading time;

  2) Wider adoption of monthly billing, resulting in a shorter period from service to payment;

  3) Customer information system updates, which reduce time required to calculate customer bills; and

  4) General process improvements.

SEC 10

Technical Conference Question

P.18

With respect to working capital:

d. Please recalculate working capital component of CND's 2014 revenue requirement with working capital value of 8.9%

RESPONSE

Using a working capital value of 8.9%, which is the difference between CND's 13% working capital allowance in 2014 and the SEC computed value from Response to SEC-10 (c), and assuming the working capital amount as per CND's 2014 revenue requirement, the amount is calculated as $1,019,798.

Energy+ does not agree that a computed change based on working capital percentages should be used as a proxy to compute the benefits derived from the transition to monthly billing. Specifically, Energy+ would note the following:

- The accounting order for the monthly billing DVA (EB-2015-0057) approved for the former CND stated the following:

  "The account will be used to record any incremental OM&A costs directly attributable to the transition to monthly billing. Costs to be recorded will be net of <u>any associated cost reductions</u> resulting from the transition, including efforts towards paperless billing, <u>improvements in cashflow or reductions in bad debt</u>." [Emphasis added]

  The accounting order did not make reference to capturing the change in working capital allowance based on the OEB's letter of June 3, 2015.

  Changes to the working capital component of revenue requirement does not constitute a cost, or cost reduction resulting from the transition to monthly billing.

  Energy+ submits that the items listed in the accounting order have been captured in the balance of the DVA, including the estimated cash flow benefit, as documented in the updated evidence.

- In its letter of June 3, 2015, the OEB also provided the view that the use of the default value for the working capital allowance (e.g. 7.5%) should only be implemented during a cost of service application. Energy+'s view is that utilizing a change in working capital allowance for purposes of computing a proxy for cost reductions in the DVA balance for the periods 2016 through 2018 with respect to the transition to monthly billing would be inconsistent with the Board's approach and constitute retroactive rate making.

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BY E-MAIL

June 3, 2015

TO: All Licensed Electricity Distributors
All Other Interested Parties

RE: Allowance for Working Capital for Electricity Distribution Rate Applications

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This letter provides an update to the OEB's policy for the calculation of the allowance for working capital for electricity rate applications.

Effective immediately, the OEB is a adopting a new default value of 7.5% of the sum of the cost of power and operating, maintenance and administration (OM&A) costs. As in the past, distributors who do not wish to use the default value can request approval for a distributor-specific working capital allowance supported by the appropriate evidence from a lead-lag study or equivalent analysis.

The OEB is also of the view that the use of the default value should only be implemented during a cost of service application, with a few exceptions as discussed further in this letter. For a custom incentive rate-setting (Custom IR) application distributors are expected to file robust evidence of costs and revenues, and the review of these applications is expected to require considerable resources from both the OEB and the distributor. It is therefore reasonable to expect distributors choosing this option to file evidence in support of their requested working capital allowance, rather than the use of a default value.

Background

Section 2.5.1.3 of the *Filing Requirements for Electricity Distribution Rate Applications* for the 2015 rate year, issued on July 18, 2014, provided for two approaches that an applicant could take for the calculation of the allowance for working capital: 1) the 13% allowance approach; or 2) the filing of a lead-lag study. The second of these approaches has been optional for all utilities that have not been directed to conduct a lead-lag study by the OEB.

The OEB has been using a default value approach to calculating working capital allowance since the 1st Generation Rate Handbook was issued in 2000. At that time, the default value was established as 15% of the total of the cost of power and OM&A expenses. By letter dated April 12, 2012, the OEB reduced the default value to 13% after lead lag studies routinely produced results of less than 15%.

It has become apparent to the OEB that average working capital requirements have been lowered as a result of a number of technical changes that reduce the actual time between service provision and payment. These include: 1) the substantial completion of the smart meter rollout and advanced metering infrastructure, which reduces aggregate meter reading time ; 2) wider adoption of monthly billing, resulting in a shorter period from service to payment; 3) customer information system updates, which reduce time required to calculate customer bills; and 4) general process improvements. The adoption of mandatory monthly billing for all distributors by December 31, 2016, should result in further downward pressure on working capital requirements. Considering all of these current and forthcoming changes, the OEB determined that a review of its approach to working capital allowance was warranted.

Working Capital Allowance for the 2016 Rate Year

The OEB continues to believe that a default value approach is an efficient alternative for setting the working capital allowance. However, a default value should not result in a working capital allowance that is reasonably expected to be higher than what would result from the use of the more accurate and detailed approach of completing a lead-lag study. The OEB also considers that maintaining a default value that is too high does not incent a utility to study its business processes and improve productivity, which would be at odds with the principles embedded in its Renewed Regulatory Framework.

Therefore, the OEB has determined that, effective immediately, the default value for working capital allowance for electricity distributors will be 7.5% of the sum of cost of power and OM&A. The default value will be reflected in the 2015 edition of the *Filing Requirements for Electricity Distribution Rate Applications* for 2016 Rate Applications.

This determination is based on a review of a range of results for lead-lag studies filed by distributors, which showed that working capital allowance results have been declining. For the applications filed for 2015 rates, the results have ranged from 7.4% to 12.7% of the sum of the cost of power and OM&A. Given that many of the financial settlement processes are common between distributors, and all distributors will be required to bill on a monthly basis by the end of 2016, the OEB is adopting a new default of 7.5%. In the OEB's judgment, this default reasonably reflects not only the range of inputs that distributors have reported to the OEB, but also the forthcoming policy changes regarding mandatory monthly billing. The adoption of this new lower default value reflects a goal that all distributors strive for best practices in their administrative processes while supporting a distributor's basic cash flow requirements.

Analysis

To support the OEB's consideration of a new default value, OEB staff reviewed eight lead-lag studies filed with the OEB since 2010 and evaluated the key factors in those studies. OEB staff also considered elements external to a distributor's own operations, such as the cost of power settlement process, and factored in the billing standards identified in the Distribution System Code, such as the identification of a minimum payment period of 16 days from the date on which a bill was issued to a customer. A summary of the results of the OEB staff analysis is attached to this letter as Appendix A. The analysis, which selected a combination of median inputs as well as values that reflect OEB policy, resulted in a calculation of a default value for the working capital allowance of 7.5%.

The OEB also commissioned a jurisdictional review to determine if there are other approaches to the funding of working capital requirements. This review is attached as Appendix B. All jurisdictions reviewed generally included an allowance for working capital to be treated as an asset, attracting a return. On this basis, the OEB does not believe that a fundamental change to its approach to funding working capital requirements is warranted.

The OEB will continue to monitor factors such as the elimination of the debt retirement charge for residential customers, the end of the Ontario Clean Energy Benefit and implementation of the Ontario Electricity Support Program as of January 1, 2016 to determine if they have an effect on cash flow.

Implementation

The new policy is effective immediately. Changes to working capital allowance costs will be implemented only in cost of service and Custom IR applications unless otherwise determined by the OEB in a prior decision. This will allow for all of a distributor's costs to be considered at the same time. The OEB adopted the same approach when it amended its cost of capital policy in 2009.

The OEB recognizes that a specific utility's own systems, processes and customer mix will influence its working capital needs. While there are similar settlement processes, lead-lag results are not directly interchangeable among utilities. Distributors can use a lead-lag study or equivalent analysis to support a request for a distributor-specific working capital allowance.

While the use of the default value will no longer be applicable to Custom IR applications, given the timing of this new policy, distributors that have filed a Custom IR application for rates effective January 1, 2016 may use the 7.5% default value to calculate their working capital allowance rather than file a lead-lag study as part of their application.

For questions relating to this amendment please contact IndustryRelations@ontarioenergyboard.ca.

Sincerely,

Original Signed By

Kirsten Walli
Board Secretary

Appendix A

Allowance for Working Capital for Electricity Distributors

June 3, 2015

Appendix A

The following is a summary of the results of OEB staff analysis, based on its review of eight lead-lag studies provided to the OEB since 2010.

	Revenue Periods (Lag Days)					Expenses (Lead Days)				
Elements of Working Capital	Service	Billing	Collection	Processing	Total	Lead Days	Net Days	Weighting Factor	Weighted Lead/Lag Days	WCF***
1 Cost of Power	15.2	17.5	22.0	1.4	56.1	(32.7)	23.40	82.8%	19.38	
2 Payroll etc.*	15.2	17.5	22.0	1.4	56.1	(9.4)	46.70	5.2%	2.43	
3 Other OM&A	15.2	17.5	22.0	1.4	56.1	(7.8)	48.30	2.8%	1.35	
4 PiLs, etc.**	15.2	17.5	22.0	1.4	56.1	(29.1)	27.00	9.2%	2.48	
5 Sub Total								100.0%	25.64	7.0%
6 HST								0.5%		0.5%
7 Total										7.5%

Element	**Determination**
Service Period	Reflects mandatory monthly billing: 365.25÷12÷2=15.22 days
Billing Period	Median based on observed range of 13.0 days to 19.0 days
Collection Period	Minimum payment period plus allowances for payments by mail as specified in s. 2.6 of the Distribution System Code. Observed sample range is 21.8 days to 29.1 days
Processing Period	Median based on observed range of 1.0 to 1.5 days
Lead Days	Median based on observed results for each expense element
HST	Median based on observed range of 0.3% to 1.4%
Weighting Factor	Reflects proportions of cost of power and OM&A expense categories based on median values from sample studies

*Payroll includes benefits. **PiLs also includes interest and debt repayment costs.
******* Working Capital Factor calculation: Weighted Lead/Lag Days ÷ 365.25 days per year + HST factor.

Working Capital -Monthly Billing

	Elements	Service	Billing	Collection	Processing	Total	Lead Days	Net Days	Weighting Factor	Weighted Lead/Lag Days	WCF
1	Cost of Power	15.22	17.5	22	1.4	56.11875	-32.7	23.41875	82.80%	19.390725	
2	Payroll etc.	15.22	17.5	22	1.4	56.11875	-9.4	46.71875	5.20%	2.429375	
3	Other OM&A	15.22	17.5	22	1.4	56.11875	-7.8	48.31875	2.80%	1.352925	
4	PILS, etc	15.22	17.5	22	1.4	56.11875	-29.1	27.01875	9.20%	2.485725	
5	Sub Total								100.00%	25.66	7.0%
6	HST								0.50%		0.0
7	Total										**7.5%**

Working Capital -Bi-Monhtly Billing

	Elements	Service	Billing	Collection	Processing	Total	Lead Days	Net Days	Weighting Factor	Weighted Lead/Lag Days	
1	Cost of Power	30.42	17.5	22	1.4	71.31667	-32.7	38.61667	82.80%	31.9746	
2	Payroll etc.	30.42	17.5	22	1.4	71.31667	-9.4	61.91667	5.20%	3.219666667	
3	Other OM&A	30.42	17.5	22	1.4	71.31667	-7.8	63.51667	2.80%	1.778466667	
4	PILS, etc	30.42	17.5	22	1.4	71.31667	-29.1	42.21667	9.20%	3.883933333	
5	Sub Total								100.00%	40.86	11.2%
6	HST								0.50%		0.0
7	Total										**11.7%**
										Difference	***4.2%***

OEB Letter Re: Allowance for Working Capital for Electricity Distribution Rate Applications, June 3 2015, Appendix

UNDERTAKING NO. JTC1.1:

ENERGY+ TO REVIEW THE REVENUE REQUIREMENT BY CUSTOMER CLASS TO CALCULATE A PERCENTAGE ALLOCATION OF THE REVENUE REQUIREMENT ATTRIBUTABLE TO CLASSES THAT WERE ON THE BI-MONTHLY BILLING THAT WERE LATER CONVERTED TO MONTHLY BILLING

RESPONSE

The following table calculates an estimate of the percentage allocation of the 2014 revenue requirement for the CND service territory attributable to classes that were converted from bi-monthly to monthly billing.

Rate Class	Distribution Revenue Requirement /1	Estimated Bi-Monthly Billing Allocation /2	Estimated Distribution Revenue Attributed to Bi-Monthly Customers
Residential	$ 13,473,027	92%	$ 12,429,698
GS < 50 kW	$ 2,894,872	39%	$ 1,116,251
Total			$ 13,545,949

Sources:
/1 2014 Cost Allocation Model EB-2014-0116
/2 Allocation estimates provided in response to Staff TCQ 2. Residential customers adjusted to remove customers on equal payment plan. GS < 50 kW adjusted to remove consumption already billed on a monthly basis.

Class	A Distribution RR (1)	B Estimated Distribution Revenue Attributed to Bi-Monthly Customers (2)	C Estimated Distribution Revenue Attributed to Monthly Customers (3)
Residential	$13,473,027	12,429,698	$1,043,329
GS<50	$2,894,872	1,116,251	$1,778,621
GS>50	$6,585,873	0	$6,585,873
GS>1000	$1,854,779	0	$1,854,779
Large User	$1,504,085	0	$1,504,085
SL	$712,403	0	$712,403
USL	$73,394	0	$73,394
ED-HONI	$30,813	0	$30,813
ED-WNH	$76,781	0	$76,781
Total	**$27,206,027**	**$13,545,949**	**$13,660,078**
		49.79%	50.21%

(1) EB-2013-0116 DRO CA Model, Tab O1
(2) JTC 1.1
(3) A-B

Working Capital - Service Lag w Monthly Billing

	Elements	Service	Billing	Collection	Processing	Total	Lead Days	Net Days	Weighting Factor	Weighted Lead/Lag Days	WCF
1	Cost of Power	15.22	17.5	22	1.4	56.11875	-32.7	23.41875	82.80%	19.390725	
2	Payroll etc.	15.22	17.5	22	1.4	56.11875	-9.4	46.71875	5.20%	2.429375	
3	Other OM&A	15.22	17.5	22	1.4	56.11875	-7.8	48.31875	2.80%	1.352925	
4	PILS, etc	15.22	17.5	22	1.4	56.11875	-29.1	27.01875	9.20%	2.485725	
5	Sub Total								100.00%	25.66	7.0%
6	HST								0.50%		0.0
7	Total										**7.5%**

Working Capital - Energy+ Service Lag Before Implementation of Monthly Billing

	Elements	Service	Billing	Collection	Processing	Total	Lead Days	Net Days	Weighting Factor	Weighted Lead/Lag Days	
1	Cost of Power	22.80	17.5	22	1.4	63.6962	-32.7	30.9962	82.80%	25.66485671	
2	Payroll etc.	22.80	17.5	22	1.4	63.6962	-9.4	54.2962	5.20%	2.823402595	
3	Other OM&A	22.80	17.5	22	1.4	63.6962	-7.8	55.8962	2.80%	1.565093705	
4	PILS, etc	22.80	17.5	22	1.4	63.6962	-29.1	34.5962	9.20%	3.182850745	
5	Sub Total								100.00%	33.24	9.1%
6	HST								0.50%		0.0
7	Total										**9.6%**
										Difference	***2.1%***

OEB Letter Re: Allowance for Working Capital for Electricity Distribution Rate Applications, June 3 2015, Appendix

1.8 MATERIALITY THRESHOLD

In accordance with the Chapter 2 Filing Requirements, an applicant must provide justification for changes from year to year to its rate base, capital expenditures and OM&A above a materiality threshold. Energy+'s materiality threshold is computed as 0.5% of the proposed distribution revenue requirement for distributors with a distribution revenue requirement greater than $10 million and less than or equal to $200 million. The materiality threshold as per the Filing Requirements is $175,852 as provided in Table 1-33. Energy+ has adopted a variance analysis threshold of $175,000.

Table 1-45: Materiality Threshold for Variance Analysis

VARIANCE ANALYSIS THRESHOLD	
	2019 TEST
Estimated Distribution Revenue Requirement	$35,170,323
0.5% of Proposed Distribution Revenue Requirement	$175,852
Materiality Threshold for Variance Analysis	$175,000

Table 9-16 provides the computation of the amount recorded in this account to December 31, 2017:

Table 9-16: OEB Assessment Fees

	Fees Paid	Fees Paid based on Last Rebasing Year			
2016	**2016 Actual**	**CND 2014**	**BCP 2011**	**Combined**	**Variance Account**
Apr 1 - June 30	71,059	37,708	10,290	47,998	
July 1 - Sept 30	71,059	37,708	10,290	47,998	
Oct 1 - Dec 31	71,052	36,842	9,825	46,667	
	213,170	112,258	30,405	142,663	70,507
2017	**2017 Actual**				
Jan 1 - Mar 31	71,052	35,798	9,970	45,768	
Apr 1 - June 30	73,459	37,708	10,290	47,998	
July 1 - Sept 30	73,459	37,708	10,290	47,998	
Oct 1 - Dec 31	69,563	36,842	9,825	46,667	
	287,533	148,056	40,375	188,431	99,102
Principle	$ 500,703			$ 331,094	$ 169,609
Carrying Charges					$ 4,819
Total					$ 174,428

Account 1518: Retail Cost Variance Account

This account is used to record the difference between revenues derived from established Retailer agreements, distributor-consolidated billings and, although not applicable for Energy+, Retailer consolidated billings, and the incremental expenses incurred to administer and process Retailer transactions and Service Agreements.

As this account has not exceeded the materiality threshold of $175,000 established in this Application, a detailed schedule identifying all revenue and expenses listed by USoA account number that are incorporated into the variances is not provided. Energy+ has followed Article 490, Retail Services and Settlement Variances of the APH for account 1518.

Energy+ requests disposition of Account 1518 for the amount of $142,626 as a charge to customers, including interest to December 31, 2018.

Account 1548: Retail Cost Variance Account-STR

This account is used to record the difference between revenues derived from Service Transaction Request services (request fees, processing fees, information request fees,

SEC 5

Technical Conference Question

P.12-13

With respect to Table 6:

a. Please split out the Energy+ column for each facility (Southworks, Garden Avenue and Bishop St.).

RESPONSE

Energy+ has prepared the following Table 6: Cost and Utilization Comparison to Other Distributors – Updated to Split Energy+ Facilities as requested.

Table 6: Cost and Utilization Comparison to Other Distributors - Updated to Split Energy+ Facilities

LDC	Energy+ (Southworks, Bishop Street & Garden Avenue Combined)	Energy+ (Southworks)	Energy+ (Garden Ave)	Energy+ (Bishop St.)	Waterloo North Hydro Inc	InnPower	Milton Hydro Distribution Inc	PUC Distribution Inc.
OEB Docket	EB-2018-0028				EB-2015-0108 EB-2010-0144	EB-2014-0086	EB-2015-0089	EB- 2012-0162
Year of Occupancy	2020/2022/2024	2022	2020	2024	2011	2015	2015	2012
Functions	Administration & Operations	Administration	Operations	Operations	Administration & Operations	Administration & Operations	Administration & Operations	Administration & Operations
Type of Project	Purchase/ Refurbish	Purchase/ Refurbish	Purchase	Refurbish	Custom Build	Custom Build	Purchase/ Refurbish	New Build
Capital Cost	$14,500,000	$8,100,000	$4,400,000	$2,000,000	$26,682,000	$10,896,704	$12,524,798	$23,000,000
Class of Estimate		Class C	Class D	Not Applicable				
Highest Class Estimate %		+20%	+30%	Assume 30% - Similar to Class D				
Square Footage	88,243	21,892	13,251	53,100	105,000	36,172	91,872	110,382
FTEs	131	67	13	51	125	41	61.5	87
Square Foot per FTE	674	327	1,019	1,041	840	882	1,494	1,269
Capital Cost per FTE	$110,687	$120,896	$338,462	$39,216	$213,456	$265,773	$203,655	$264,368
Capital Cost/Square Foot	$164.32	$370.00	$332.05	$37.66	$254.11	$285.79	$136.33	$208.37
Capital Cost @ Highest End of Estimate Range	$18,040,000	$9,720,000	$5,720,000	$2,600,000				
Capital Cost/FTE @ High Range	$137,710	$145,075	$440,000	$50,980				
Capital Cost/Square Foot @ High Range	$204.44	$444.00	$431.67	$48.96				

Notes:

WNH	Amount based on Actual Costs as provided in EB-2015-0108
InnPower	Amount based on OEB Approved as per Settlement Agreement in EB-2014-0086. Settlement included a reduction of $2,909,000.
	Actual costs as per EB-2016-0085 were $13,491,210, however OEB approved Settlement Amount plus $244,506 for Furniture/Fixtures.
	Amount in table should be $11,141,210 ($10,896,704 plus $244,506)
Milton Hydro	Amount based on OEB Decision in EB-2015-0089. Actual costs were $14,460,000 less disallowed amounts of $1,935,202.
	Amount was revised as part of Motion to Review (EB-2016-0255) to add back $505,950 of a capital gain that should not have reduced rate base.
	Amount in table should be $13,030,748 ($12,524,798 plus $505,950)
PUC Distribution	Amount based on OEB Decision on Cost of Service, which was based on estimate.
	Actual costs as per EB-2017-0071 were $24,789,141, which were accepted as part of rate base as part of the Settlement.

7–SEC-39

INTERROGATORY

Ref: Ex.7, p.13-14

With respect to the proposed capacity/standby charge, the Applicant states: “On an annual basis Energy+ will review the monthly peak loads and after a discussion with the customer possibly adjust the contracted capacity reserve value.”

a. What factors will the Applicant consider in determining if it will lower the contracted capacity?

RESPONSE

In reviewing the monthly peak loads and based on discussions with the customer, it is possible that the contracted capacity could be increased or decreased. Factors that would be considered include, but are not limited to:

- If there has been a material decrease in the amount of peak load utilized in the year compared to the contracted capacity and the historical years. A discussion with the customer to ascertain if there are any particular reasons for the decrease in peak load, and whether or not the customer anticipates that this decrease in peak load will continue (e.g. conservation initiatives that are persistent such as new air compressors);
- If there has been a material increase in the amount of peak load utilized in the year compared to the contracted capacity and the historical years. A discussion with the customer to ascertain if there are any particular reasons for the increased peak load, such as issues with the load displacement generation, changes in load requirements for business reasons, etc., and the impact that these changes may have on the future expected capacity requirements;
- Customer wishes to elect to contract for a lesser amount as it intends to shed load when the generation is not available;
- Customer has implemented additional technology that reduces the need for the full amount of the contracted capacity for back up; and
- Customer elects to cancel the contract for back-up capacity.

7–SEC-39

INTERROGATORY

Ref: Ex.7, p.13-14

b. What happens if the Applicant and the customer disagree? How will the disagreement be resolved?

RESPONSE

Energy+'s Conditions of Service outlines the disputes procedures for customers in Section 1.8 Dispute Resolution. The procedure approaches dispute resolution through internal investigation and discussions with staff who are subject matter experts. If these discussions fail to resolve the matter, the dispute is then escalated to the President & CEO. The final recourse for a customer dispute is to seek independent advice from the Ontario Energy Board.

7–SEC-39

INTERROGATORY

Ref: Ex.7, p.13-14

c. Will the Applicant require the customer to enter into any contract or agreement regarding the contracted capacity? If so, please provide a copy of the proposed agreement.

RESPONSE

Energy+ will require customers to enter into an agreement for the contracted capacity. Energy+ has not prepared an agreement at this time.

7–SEC-40

INTERROGATORY

Ref: Ex.7, p.14-15

The Applicant states: “Energy+ also proposes to apply this same approach to the General Service > 50 to 999 26 kW and General Service > 1000 to 4999 kW rate classes when a customer in these classes would have load displacement generation. In this case, Energy+ would consult with the customer and determine that power will be needed when the generation is not running.”

a. How will the Applicant determine the appropriate contracted capacity?

RESPONSE

Energy+ will work with each customer to determine the appropriate level of contracted capacity. An appropriate contracted capacity will likely depend upon a number of customer driven factors including:

- The current and historical peak loads of the customer, in the absence of the load displacement generation (“LDG”);
- The size and capacity of the proposed LDG facility;
- Understanding of whether the customer requires Energy+ to be on standby to supply capacity in the absence of the LDG facility not operating; and
- If the customer is requesting a contracted capacity level that is below the capacity of the LDG facility, how much of the load can the customer curtail instantaneously to ensure that the contracted capacity level is not exceeded.

<u>7–SEC-40</u>

<u>INTERROGATORY</u>

<u>Ref: Ex.7, p.14-15</u>

b. What happens if the Applicant and the customer disagree on the appropriate contracted capacity? How will the disagreement be resolved?

<u>RESPONSE</u>

Energy+'s Conditions of Service outlines the disputes procedures for customers in Section 1.8 Dispute Resolution. The procedure approaches dispute resolution through internal investigation and discussions with staff who are subject matter experts. If these discussions fail to resolve the matter, the dispute is then escalated to the President & CEO. The final recourse for a customer dispute is to seek independent advice from the Ontario Energy Board.

7–SEC-40

INTERROGATORY

Ref: Ex.7, p.14-15

c. Does the customer have an ability to adjust the contracted capacity over time? If so, please provide details.

RESPONSE

Yes, the customer will have an ability to adjust the contracted capacity over time. As described in Response to Interrogatory 7-SEC-39, factors that would be considered by the customer and Energy+ would include:

- If there has been a material decrease in the amount of peak load utilized in the year compared to the contracted capacity and the historical years. A discussion with the customer to ascertain if there are any particular reasons for the decrease in peak load, and whether or not the customer anticipates that this decrease in peak load will continue (e.g. conservation initiatives that are persistent such as new air compressors);

- If there has been a material increase in the amount of peak load utilized in the year compared to the contracted capacity and the historical years. A discussion with the customer to ascertain if there are any particular reasons for the increased peak load, such as issues with the load displacement generation, changes in load requirements for business reasons, etc., and the impact that these changes may have on the future expected capacity requirements;

- Customer wishes to elect to contract for a lesser amount as it intends to shed load when the generation is not available;

- Customer has implemented additional technology that reduces the need for the full amount of the contracted capacity for back up; or

- Customer elects to cancel the contract for back-up capacity.

7–SEC-40

INTERROGATORY

Ref: Ex.7, p.14-15

d. Will the Applicant require the customer to enter into any contract or agreement regarding the contracted capacity? If so, please provide a copy of the proposed agreement.

RESPONSE

Energy+ will require customers to enter into an agreement for the contracted capacity. Energy+ has not prepared an agreement at this time.

Ontario Energy Board | Commission de l'énergie de l'Ontario

February 21, 2019

Staff Report to the Board

Rate Design for Commercial and Industrial Electricity Customers

Rates to Support an Evolving Energy Sector

EB-2015-0043

2300 Yonge Street, 27th floor, P.O. Box 2319, Toronto, ON, M4P 1E4
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The design of the CRCs would achieve the following objectives as set out by the OEB in its May 2015 letter:

D.4 – Proposed Capacity Reserve Charges for Customers with Generation

Many GS≥50kW, Intermediate and Large customers will consider distributed energy resources as a way to lower their costs. The OEB Strategic Blueprint speaks to enabling innovation that enhances consumer choice and control. Staff have developed a proposal to enable customer choice while meeting the general rate policy of ensuring fairness in the recovery of costs to maintain a reliable distribution system. The intention is to ensure that distribution systems' pricing is not a barrier to customer innovation while ensuring that the costs of the system are fairly recovered from those who are using it. These changes will only affect those customers who have behind the meter generation.

Under the current rules, the following scenario has happened in more than one distribution service area. A customer in the large class of a distributor without a standby class who is already a load decides to install distributed generation for essentially all its load. Its transmission cost is billed based on gross load (i.e. the delivered load plus its self-provided load) as per the transmission rate order. It has reduced its monthly demand significantly except for the one month during which it services the generator where its demand on the distribution system is for its full load. Over the course of the year, the customer pays the fixed Monthly Service Charge and likely very else for distribution. As a result the distributor under-recovers for that class until it reviews the allocation of cost for all classes and resets rates.

Since total costs have likely not gone down, due to the long-term nature of distribution system investments, and therefore the revenue requirement for the distributor has not gone down, those costs are reallocated to other classes when rates are reset. The amount that those other classes have to pay goes up and the demand charges in all classes (including the large class) go up. Meanwhile, the distributor must continue keep the full capacity reserved for the customer's once a year servicing and the customer has no incentive to keep its once a year demand in off-peak times.

The OEB commissioned work by Navigant[28] that shows that relatively low penetrations of load reductions can have significant effects on distributor revenue.

Table 4: Distributor Revenue Impact of Reducing Demand using Current Tariffs

LDC	GS < 50	GS >= 50	Large
Entegrus	-4.5%	-8.8%	NA
Hydro One (Rural)	-7.9%	-9.7%	NA
Hydro One (Urban)	-7.3%	-9.6%	NA
Orangeville	-5.4%	NA	NA
PowerStream	-5.7%	-9.3%	-7.0%
Toronto Hydro	-6.2%	-9.8%	NA

Table 5: Distributor Revenue Impact of Reducing Demand Using Proposed Tariffs for GS < 50kW

LDC	GS<10	GS 10 - 50
Entegrus	0.0%	-6.6%
Hydro One (Rural)	0.0%	-9.2%
Hydro One (Urban)	0.0%	-8.7%
Orangeville	0.0%	-7.7%
PowerStream	0.0%	-7.5%
Toronto Hydro	0.0%	-8.1%

Source: Navigant Analysis

By implementing a Capacity Reserve Charge (CRC), charges that fluctuated with standby charges will become a fixed charge based on the amount of generation installed. This leads to a more cost reflective recovery of costs from these customers who are expecting the system to be there on demand.

Staff have provided some illustrative graphs to try to show the difference between standby charges, contract demand with penalties, and the proposed emergency backup service. Figures 10, 11 and 12 below provide a comparison of the way that standby, contract demand and capacity reserve charges would work. These graphs are to demonstrate and contrast the concepts and do not represent any particular jurisdiction. The grey bars are the underlying distribution charge based on measured demand. The orange bars represent extra charges based on the operation of the installed generation.

[28] See tables 6 and 8 in Appendix B.

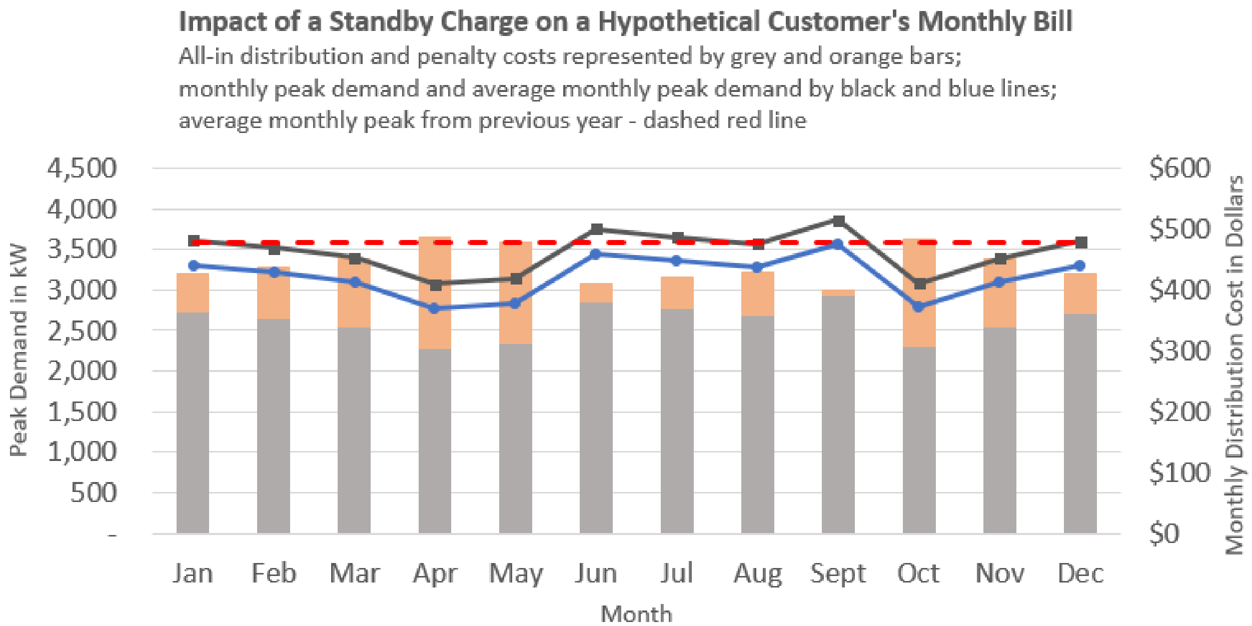

Figure 10: Sample of Standby Charge

For standby charges, there is a fluctuating charge to account for the amount of generation provided on-site. The grey bars are underlying demand charge and the orange bars are a standby charge meant to recover the distribution costs of "standing by" ready to supply the balance of the load being provided by the generator.

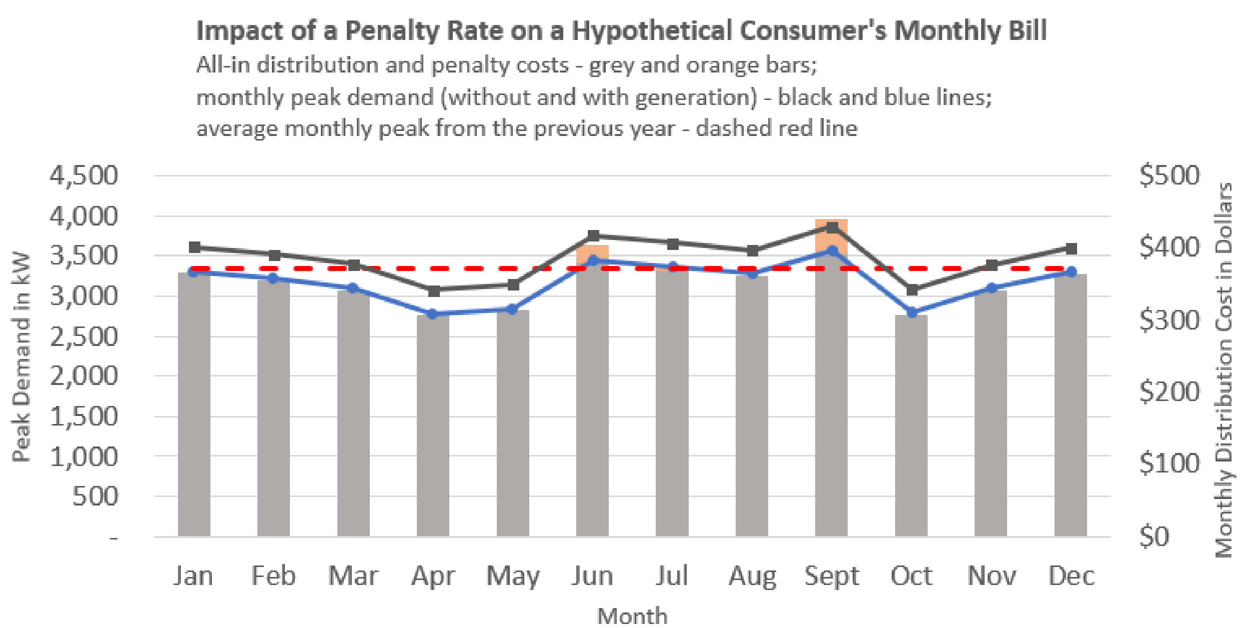

Figure 11: Sample of Contract Demand with Penalty Rate

For a contract demand, there is a penalty charge for demand above the contracted amount. The grey bars are the normal demand charge and the orange bars are penalty charges for going over the contracted demand. The penalty charge is at a significantly higher rate than the normal demand charge.

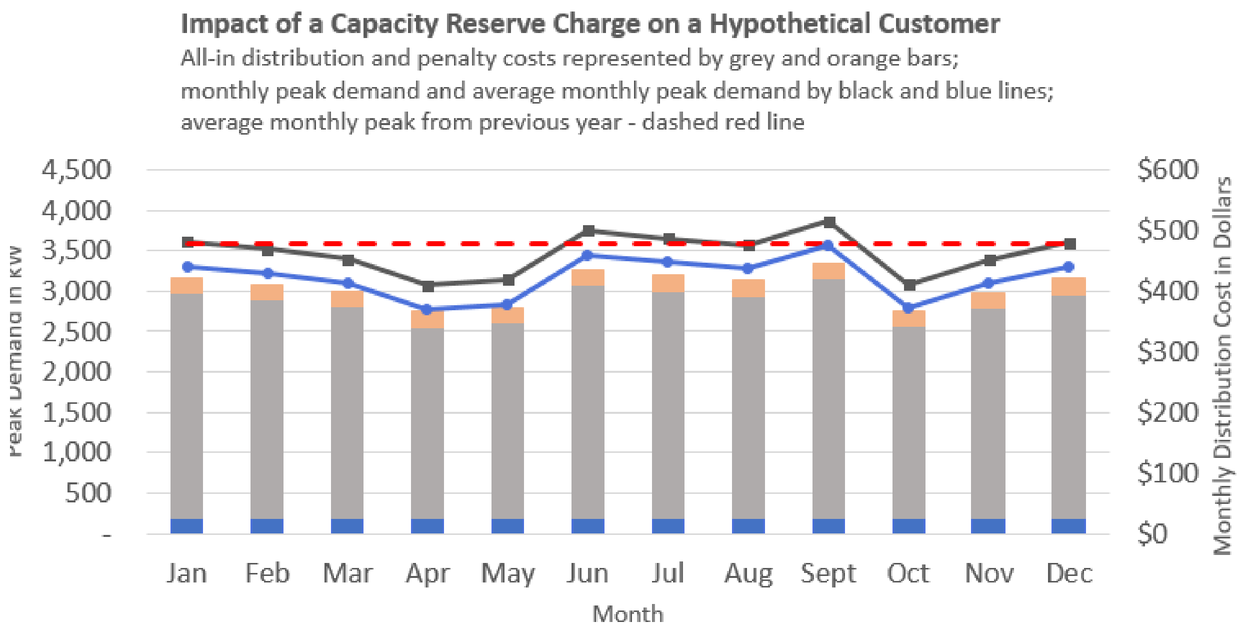

Figure 12: Sample of a Capacity Reserve Charge

For the Capacity Reserve Charge, the blue bars are the Monthly Service Charge, the grey bars are the demand charge for the class and the orange bars are the CRC. The CRC is a fixed monthly amount that represents a payment for capacity being held in the system that the customer will not otherwise be paying over the course of the year. Staff now recommend that it be based on the faceplate rating and the capacity factor of the of the generator and the underlying demand rate of the class.

The CRC payment is intended to compensate for capacity being held for the customer in the system. It should represent that value as closely as possible without either avoided costs that will end up being shifted to other customers or being a windfall for the distributor and skew the economic decisions of the customers.

Staff's initial proposal for a CRC was to set a fixed factor intended to prevent distributors from over-collecting. The work by Navigant suggested that this factor would be 90%. Staff proposed that this factor would decrease over time as a generator proved reliable service to the distributor, and the need for back-up capacity lessened. Staff's thinking was that this would provide an incentive for the operators to maintain their installation and would allow distributors to reduce the capacity held in the system for that connection.

Staff took these ideas to customers with existing onsite and load displacement generators, such as the Ontario Power Plant Administrators Association, Canadian Manufacturers & Exporters and the Association of Major Power Consumers in Ontario They pointed out that running a generator flat out to replace all load is typically not how they operate. They described other factors that influence how the customer runs its load displacement generator.

- Resource limited: Solar or wind or other renewable generators are often intermittent based on fuel availability.
- Emissions-limited: Emergency generators with a Certificate of Approval from the Ministry of Energy are limited to the number of hours they can run based on emissions. These generators may be running otherwise required tests of equipment in hours to participate in the ICI program.
- Requirements limited: Combined heat and power (CHP) plants may be heat following rather than having the goal of optimizing electricity output.
- System operations limited: Physical plant operators pointed out that their distributor will sometimes request that they not run for operational purposes of the host system.

Based on this feedback and further analysis of the system data, staff have revised the proposal for calculation of the CRC. The high level concept of the CRC remains the same. However, staff are now recommending that the proposed calculation reflect the expectation that generation is displacing load based on using a capacity factor. A capacity factor (CF) is the ratio of a generator's actual output over a period of time, to its potential output if it were possible for it to operator at full nameplate capacity continuously over the same period of time. Capacity factor is specific to the technology and more specifically to how the generator is run. For examples of potential capacity factors, see Table 6.

The CRC would be a fixed payment that is made monthly in addition to the variable charge for the metered maximum demand in the billing period. Unlike traditional standby charges that attempt to reach a contracted level every month, the CRC should recover the capacity payment on average over the year. By including capacity factor, the CRC would take into account the expectation that the customer will reach and pay for full or partial load at some point in the billing cycle.

Renewable energy generation is also referred to as intermittent generation since it depends on immediate fuel. At some point in each month or billing period, the sun will not shine or the wind will not blow during a customer's peak load. It is likely that the distributor will provide full service almost every month for renewable generation. The customer will pay the full distribution bill for its full demand load. The capacity factor for renewable plus storage installations would be higher. If the customer has its own storage, it is able to store power during times of generation excess and use this during periods when the renewable fuel source is not available. And if there was not enough of its own generation, it could store power from the grid to use when the renewable fuel source is not available. A customer with renewable generation plus storage would be able to manage to avoid drawing its full power from the grid and the capacity factor is higher.

Staff recommend that the only type of Capacity Reserve Charge available to GS ≥50kW customers is for full Emergency backup service.

Emergency backup service (EBS) is a full emergency service that is instantaneously (or nearly instantaneously) available if the customer's generator fails for any reason. Since the distributor must maintain full capacity for this customer including like-for-like asset replacement, the distributor should charge a capacity reserve charge that is based on the normal demand charge for the class and the full value (faceplate rating) of the generator and projected or historic levels of capacity factor.

EBS = Faceplate capacity rating x Demand rate of class x Capacity Factor

Some customers keep a generator on premises to provide their own emergency backup generation in the case of grid failure. Hospitals or large commercial buildings will sometimes do this in addition to manufacturers who want to ensure that they are not subject to a lengthy service disruption. These generators often use diesel for fuel and are subject to environmental restrictions and certification to limit their emissions.

Some customers are using these backup generators to participate in the Industrial Conservation Initiative (ICI) program. The ICI program allows participants to reduce their global adjustment costs and help the provincial system defer the need for investments in new electricity infrastructure that would otherwise be needed. These emission limited generators have a very low capacity factor and would pay a very low capacity reserve charge since the customer is expected to draw full load almost every month.

In staff's previous proposal, installations like renewable energy and emissions-limited generators would have had to be exempted. Under the new proposal, the capacity factor should account for the expected level of charge for load.

The IESO included standard capacity factors in Feed In Tariff (FIT) contracts to recognize expected output. The IESO also uses capacity factors in their planning for the same reason. Table 2 is some typical capacity factors. Staff expects to be able to add to and refine this table before implementation. In addition, staff expects that for Large customers, especially those with existing installations, the Capacity Factor can be agreed between the customer and the distributor and potentially adjusted periodically.

Table 6: Samples of Capacity Factors for Technologies Based on IESO System Planning

Type	Installation	Capacity Factor
Solar	Rooftop – fixed	10
	Ground mounted – fixed	20
	With storage	50
Wind	Fixed	30
	Orienting	35
	With storage	50
Bioenergy	Standard	40
	With storage	50
CHP	Heat following	50
	Full operation	65
Fossil	Certificate of approval limited	15

Implications of the proposed approach

The CRC should make the distributor indifferent to the installation of distributed generation in the service area and so enable customers to install new technology.

Customers should be able to decide on installing generators based on the commodity savings and other factors relevant to their business (e.g. control of generation, power quality, reliability of supply, or non-economic factors like support for green energy). Their decision will not disadvantage other customers through cost shifting.

D.5 – Implementation Issues for Capacity Reserve Charges

Since the new CRC charges only affect customers that are making a change and adding distributed generation, the OEB expects that these can be implemented immediately subject only to appropriate changes in distributor CIS systems. Some customers have existing generators and may or may not be paying standby charges to their distributor. Staff proposes that any current standby charges would be converted to CRC at a distributor's next rate case.

Staff further proposes that any existing generators not currently subject to standby charges begin to pay CRC on a phased-in basis. Existing installations represent an investment by the customer based on the previous rules. At the same time, any existing installation has, from an accounting perspective, depreciated over time with a concurrent increase in return. Staff therefore proposes that the applicable amount of the CRC applied every year increase by 10% of the total. i.e. reach 100% of the CRC in 10 years. This would be in line with depreciation levels for a major asset so that the CRC is implemented only as an existing installation depreciates.

D.6 – Specific Service Options for Large Customers

Large customers are very sophisticated about their energy use. They often have someone whose responsibility is planning for energy use and how to minimize costs. Staff are proposing that they have more choice[29] with regard to their level of service and consequently the amount that they pay for it. This will allow them to make decisions that support their business and respond to the circumstances around them.

At the same time, their decisions can have immediate effect on the operation of the distribution system that ultimately affect the costs allocated and charged to other customers. Their business decisions must not be allowed to disadvantage other customers.

Their decisions should be coordinated with distribution system planning to ensure that distributors can take advantage of opportunities for cost containment and are not surprised by customer actions. Distribution companies will need to discuss with each

[29] In conjunction with the levels used in regional planning, staff are suggesting that these options only apply to Large class customers, those over 5MW of demand.

customer what level of service is required and how it will be accomplished. These customers are few in number and more individual attention is warranted.
In addition to the Emergency backup service (EBS) available to GS ≥ 50kW customers, staff recommend that Large customers be able to choose Maintenance service or paying a Bypass charge.

Maintenance service (MS) would be negotiated with the distributor to provide full load at off-peak times at the distributor's discretion. Since the additional cost to the distributor is low for maintenance service, the charge should be lower than EBS. However, since the customer is abandoning load, there should be some form of recalculated economic test as an exit payment. It would include the net book value of dedicated assets and some upstream assets as well as the cost of the load limiter. The cost of removing and reinstalling the load limiter would be charged whenever the customer requires the service. Under this model, the customer is taking the risk of poor performance of the generator and that it will not be able to supply the load.

MS = Faceplate capacity rating x Demand rate of class x Maintenance Factor

> Where Maintenance Factor is negotiated with the distributor such as between 25% and 50%. For the purposes of comments, assume that the OEB chooses 30% as the Maintenance Factor.

Bypass is when a customer is essentially taking most or all load off the system. There would be a calculation of the value of abandoned assets so that the remaining costs of assets built to serve the customer (in particular feeder lines, controls, and protection systems) are not passed to the remaining customers.

Bypass could be full for disconnection or partial where some load remains on the system. There will be an economic evaluation to determine the payment owing for the value of the abandoned assets to calculate a full or partial bypass charge.

Full Bypass charge = Net Book Value of abandoned assets and system costs based on the load being abandoned

Partial bypass is when the customer wants to permanently remove their load from grid service but maintain a connection to the grid. The customer may choose to reduce their load to some minimum and protect the rest with emergency backup or maintenance levels of service from the distributor. The customer should pay out the net book value (NBV) of connection assets built to serve them, offset by the expected continuing revenue stream which may only be the Monthly Service Charge or may include some load and/or level of Capacity Reserve Charge.

During the OEB's consultation on the Regional Planning and Cost Responsibility Review[30] (Cost Responsibility consultation) which was recently completed, a number of stakeholders requested clarification in relation to how a bypass compensation charge in that consultation would work with the capacity reserve charge (CRC) being considered in this consultation.

The primary stakeholder concern was the potential for a customer being required to pay both charges to compensate the distributor for the same bypassed capacity (i.e., charged twice). In its Revised Notice of Proposal[31] related to the Cost Responsibility consultation, the OEB noted that clarification was not possible at that time, since both bypass compensation and the CRC were at the proposal stage[32]. As a consequence, in that Notice, the OEB indicated it would address the relationship between the two charges, as part of this policy consultation process, once the Cost Responsibility consultation was concluded.

OEB staff notes that bypass compensation is broader in scope than the CRC. Unlike the CRC, it is not limited to cases of bypass involving embedded generation. For example, a bypass compensation charge would be applied where bypass is achieved through wires reconfiguration, such as a customer that shifts existing load from the distributor's facilities (e.g., transformation station) to its own duplicative facilities that the customer later constructed.

Where embedded generation is involved, renewable generation is also exempt from the requirement to provide bypass compensation. As a result, the comments requesting clarification appear to be limited to one bypass scenario in relation to where both charges could potentially be applied. That scenario involves the customer installing behind-the-meter non-renewable generation (e.g., natural gas CHP). OEB staff further notes that, as reflected in the final DSC amendments in the Cost Responsibility consultation[33], for distribution-connected customers, bypass compensation will also be limited to large consumers which the OEB concluded will be those with a non-coincident peak demand of 5 MW and above (i.e., large user rate class for distribution charges). In contrast, the currently contemplated threshold for the CRC is much lower as it would be

[30] EB-2016-0003
[31] Notice of Revised Proposal
[32] Ibid, p. 23
[33] Notice of Amendments to Facilitate Regional Planning

applicable to customers over 50 kW. However, under the CRC proposal, bypass options will only be available to Large customer classes.

Bypass compensation is now required for both *full* and *partial* bypass within the distribution system. The potential where bypass compensation and the CRC could be applicable is related to partial bypass. Under a full bypass scenario, the customer fully disconnects from the distributor's system. That would not occur under any CRC scenario since the customer is maintaining its connection to reserve capacity on the system, so they can use it as needed.

Based on the above, the only scenario where both charges could be applied is therefore where a large customer (over 5 MW) has embedded non-renewable generation to supply some of its load. Key differences on the implementation side are bypass compensation is a *one-time charge* – calculated based on the remaining net book value (NBV) of the bypassed asset(s) – due to a customer *permanently* removing its load from the distributor's system. In contrast, the CRC is an *ongoing charge* and the customer is *not permanently* removing a certain amount of load from the system. Instead, they are reserving capacity for when they need it from time to time.

Under the staff proposal for the CRC, the stakeholder concern noted above will never be realized. That is, there will never be a case where a customer would be charged both the CRC and bypass compensation in relation to the same capacity. A key reason for that is it will be based on *customer choice*; i.e., not determined by the distributor which charge is applied.

Paying bypass compensation may be the lower cost option for a customer over the longer term, but they would be assuming the risk of no longer being able to rely on the system to supply all of their electricity needs. In contrast, the customer would be able to continue to rely on the system when they need it if they opt to pay the CRC for the capacity they reserve, so it is like an insurance policy.

To use an analogy, the customer's decision is similar in nature to a customer deciding on whether they want to purchase and own their water heater (after they have rented it for some time) <u>or</u> continue to rent and pay an ongoing monthly charge. If they choose to pay the remaining NBV and own it, they assume the risk to repair and/or replace the water heater, whereas if they continue to rent, the risk remains with the company to service the water heater and/or replace it.

A hypothetical example is set out below based on a customer that has existing demand of 100 kW and they install gas-fired embedded generation that can supply 20% of their load.

Total existing customer demand	100 kW	
Demand supplied by new LDG gas generation	20 kW	BC or CRC applies
Demand remaining on distribution system	80 kW	Unaffected

In the example above, under staff's recommendation, if the customer opted to pay bypass compensation, the capacity allocated to them would be limited to 80 kW. On the other hand, if they opted to pay the CRC, they would still have access to the full 100 kW, but they would pay the CRC in relation to 20 kW in order to pay for services received from the distributor, including maintaining capacity on the distribution system that is reserved for them. OEB staff notes this is only an example, as the customer could opt to reserve less than 20 kW.

D.7 – Implementation Issues for Large Customer Options

Treatment of Demand Overages

One implementation issue for maintenance and bypass is how to ensure that customers do not access emergency backup service without paying for it. There could be some penalty imposed for customers who are only paying for the limited service but whose generator fails and end up using full emergency backup. This could be a physical limitation or financial penalties.

One possibility for a customer that remains connected to the grid is that the distributor installs a load limiter at the customer's service to ensure that it does not draw more than the agreed amount. Under this model, the customer is taking the risk of poor performance of the generator and that it will not be able to self-supply the load. A distributor who has limited capacity on a line or faces an end-of-life replacement decision many need to physically limit the demand that a customer can draw. In this case, a customer who discovers that it actually needs full emergency backup could end up paying significant fees to install and then reverse load limiters. The distributor may make decisions based on an expectation of the customer's reduced load that then needs to be served again.

Another way of dealing with overages is to apply penalty rates to any demand over the agreed load. Network providers in the UK apply excess capacity charges[34] to demand over the agreed supply capacity. The penalties try to discourage companies from exceeding their agreed supply capacity to assist the distribution network operators with balancing network usage. The penalty rate depends on the specific distributor but ranges from 15% to 106%[35] above the base demand rate.

When penalty charges apply, a customer is taking a business risk of overage charges but not an operational risk of not having enough service. A distributor with excess capacity may prefer to allow a customer to draw over the agreed demand and incur penalties that would offset charges for other customers rather than install more equipment to have a physical limitation. The application of penalties would prevent customers from trying to game the system by choosing a lower level of service and using the higher level.

Links to Distribution System Planning

For Large customers, economic tests could be done on an individual basis. These calculation could include credit for system benefits specific to the generator and location. However, the distributor should not continue on with business as usual planning models. The distributor should assume some risk of load change.

In consultation, customers noted that installation of a large distributed generator is not a momentary decision. Developing the business case, the dedication of capital, and construction is likely a 7 year program.

The OEB began asking distributors for specific, 5-year system planning information in 2009. The filing requirements for those plans have increased in detail since then. Distributors are also expected to find out their customers experience and expectations for service level and quality. OEB expects distributors to involve customers in planning. For larger customers, this could be discussing replacement plans as dedicated assets reach their end of life. Without evidence that these kinds of consultation have taken place, the distributor would not be entitled to include those assets in the economic evaluation of NBV.

[34] Distribution Connection and Use of System Agreement (DCUSA) DCP161 - Excess capacity charges | Ofgem
[35] Professional Cost Management Group summary of excess capacity charges

Implications of Maintenance Service and Bypass

Staff believe that the proposal addresses the objectives of the project.

- It addresses concerns of distributors and customers that the level of change in the sector is already overwhelming in that it maintains the status quo for underlying rate and only applies to advanced customer installing or operating distributed generation.
- It allows for customer choice in the level of service provided by the distributor of full emergency backup service, maintenance service, or full or partial bypass.
- Customers can choose to install distributed generation to lower their bills through savings on commodity. However, they will not avoid paying for the capacity maintained in the system and thereby shift costs to other customers.
- It enables technology implementation by making the distributor indifferent to customer installation of distributed generation.

Chapter 5

5. Direct Allocation

Directions on the direct allocation method to be used in the cost allocation filings are presented in this Chapter.

5.1 Background

As an initial step in a cost allocation study, a distributor should identify any significant distribution facilities that are dedicated exclusively to only one customer rate classification. The costs of such a facility, and the associated O&M expenses, should then be directly allocated to the customer classification that it is exclusively dedicated to. To prepare and review proposed direct allocations will take time and effort and therefore it is not encouraged for items that a distributor considers insignificant.

Direct allocations may not prove that common in practice, as more than one customer classification may make use of the facilities in question.

A stakeholder has asked for clarification of how to apply direct allocation where the customer in question has access to other parts of the system for additional reliability. For instance, there may be a situation where a facility (most likely a conductor) is directly assignable to a large customer as the feeder provides service to only the large customer under normal circumstances; however, under emergency circumstances there is access to back-up service provided through other facilities on the distributor's integrated system. Under this situation, it is appropriate to charge this large customer for a share of the facilities providing this redundancy or back-up, along with the full cost of the directly assignable facilities. If this situation arises, the distributor should provide a full explanation and documentation of how the directly assignable facilities, as well as the appropriate assignment of back-up facilities, are allocated to the large customer. The large customer's NCP should be used as the default allocator in these situations, but an alternative allocator may be used if supported by an adequate justification and supporting documentation (including a summary of the difference arising from use of the alternative allocator).

The consultations for this project indicated direct allocation should be explored in the following circumstances:

- A Transformer Station owned by a distributor that is 100% dedicated to customer(s) in the same rate classification.
- A feeder that is 100% dedicated to customer(s) in the same classification.
- Costs directly associated with load displacement generation assets.

Q. WHAT FURTHER CHANGES HAVE YOU MADE TO SCHEDULE JP-5 THAT ARE NOW REFLECTED IN SCHEDULE JP-11?

A. First, **Schedule JP-11** corrects several inadvertent errors and incorporates more up-to-date information. Second, as previously stated, **Schedule JP-11** is based on two Large Use classes in contrast to the Settlement CCOSS and my One Large Use Class/Partial Direct Assignment study (**Schedule JP-5)**, which are both based on one Large Use class. Third, in **Schedule JP-11**, I directly assigned all distribution costs (with the sole exception of the primary poles) to TMMC using Energy+'s Direct Assignment Study, whereas only the costs of the M24 and M30 Feeders were directly allocated in **Schedule JP-5**. Finally, unlike in **Schedule JP-5**, I did not allocate any >50 kV (Bulk) distribution costs to TMMC and to the other Large Use customer in **Schedule JP-11**.[8]

Q. PLEASE DESCRIBE THE SPECIFIC CHANGES IN SCHEDULE JP-11.

A. There are two specific changes. The first change is a correction to the demands and associated allocation factors due to the inadvertent removal of the wholesale market participants' adjustments to the GS >50 kilowatt (kW) classes. The second change reflects the use of more up-to-date data, namely the revenue requirement settlement reached by Energy+ and intervenors and filed with the Board on December 12, 2018 (Settlement Proposal).

[8] In **Schedule JP-5** as updated in **Appendix C** of this evidence, the >50 kV distribution costs were allocated to all retail customer classes, including the Large Use class.

TREATMENT OF BULK vs. RTSRs

SIMPLIFIED EXAMPLE

ASSUMPTIONS:

- Two customers classes – Customer Class A consists of customers served at secondary voltage while Customer Class B consists of those customers served at primary voltage.
- However, at the primary distribution level, both customer classes have the same load profile and therefore the same demand allocators for Bulk Facilities.
- Total revenue requirement associated with Bulk Facilities (>50 kV) - $2,000
- Total cost associated with RTSR-Transformation Connection (HON-TX owned) - $8,000
- For Customer Class A: 50% of the load is served by Bulk Facilities and 50% by HON-Tx owned Transformation.
- For Customer Class B: 100% of the load is served by HON-Tx owned Transformation Connection.

SCENARIO ONE

- Bulk costs and RTSR-related costs both allocated to customer classes based on total load in each **class:**

Customer Class	Bulk Facilities	RTSR	Total
- Customer A	$1,000	$4,000	$5,000
- Customer B	$1,000	$4,000	$5,000
Total	$2,000	$8,000	$10,000

SCENARIO TWO

- Bulk costs only attributed to those using the facilities. RTSR-related costs allocated to all customer classes based on total load for each class.

Customer Class	Bulk Facilities	RTSR	Total
- Customer A	$2,000	$4,000	$6,000
- Customer B	-	$4,000	$4,000
Total	$2,000	$8,000	$10,000

SCENARIO THREE

- Bulk costs and RTSR-related cost both attributed based on use of related assets.

Customer Class	Bulk Facilities	RTSR	Total
- Customer A	$2,000	$2,667	$4,667
- Customer B	-	$5,333	$5,333
Total	$2,000	$8,000	$10,000

VECC-TCQ - 76

Issue: 3.2 Are the proposed cost allocation methodology, allocations, and revenue-to -cost ratios appropriate?

Reference: Settlement Proposal – Cost Allocation Model

a) Please confirm whether the cost allocation methodology used in the Cost Allocation Model filed with the Settlement Proposal represents Energy+'s cost allocation proposal for purposes of setting 2019 rates.

RESPONSE

a) The cost allocation methodology used in the Cost Allocation Model filed with the Settlement Proposal does not represents Energy+'s cost allocation proposal for purposes of setting 2019 rates.

Please refer to Response to VECC-TCQ-76 b).

VECC-TCQ - 76

Issue: 3.2 Are the proposed cost allocation methodology, allocations, and revenue-to -cost ratios appropriate?

Reference: Settlement Proposal – Cost Allocation Model

b) If not confirmed, please outline the changes that Energy+ would make and provide an alternative cost allocation model that incorporates these changes.

RESPONSE

Energy+ has provided an alternative cost allocation model in live excel format.
2019 Energy+_Cost_Allocation_Model VECC 76b.xls.

i) The load forecast has been updated as per response to VECC-TCQ – 66b)

ii) Account 1805-1 Land Station >50 kV has been assigned 100% of 1805 in Tab I4 BO ASSETS

iii) Account 1808-1 Buildings and Fixtures > 50 kV has been assigned 100% of 1808 in Tab I4 BO ASSETS