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

DECISION AND ORDER

EB-2018-0028

ENERGY+ INC.

Application for electricity distribution rates and other charges beginning January 1, 2019

BEFORE: **Michael Janigan**
Presiding Member

Emad Elsayed
Member

June 13, 2019

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1 INTRODUCTION AND SUMMARY

This is a decision and order (Decision and Order) of the Ontario Energy Board (OEB) on an application filed by Energy+ Inc. (Energy+) on April 30, 2018 to change its electricity distribution rates effective January 1, 2019 (the application). Under the *Ontario Energy Board Act, 1998*, distributors must apply to the OEB to change the rates they charge their customers.

Energy+ provides electricity distribution services to approximately 65,000 residential and commercial customers within the City of Cambridge, the Township of North Dumfries and certain areas within the County of Brant.

Cambridge and North Dumfries Hydro Inc. (CND Hydro) and Brant County Power Inc. (BCP) amalgamated to form a consolidated entity on January 1, 2016 under the electricity distribution license for Energy+ Inc.[1] Distinct rate schedules for the two service areas were maintained until this application in which Energy+ proposed to harmonize distribution rates and specific service charges for the two service areas.

Energy+ requested that the OEB approve its rates for five years using the Price Cap Incentive rate-setting (Price Cap IR) option available under the *"Renewed Regulatory Framework for Electricity Distributors: a Performance Based Approach"*[2], as most recently set out in the *Handbook for Utility Rate Applications.*[3] Under the Price Cap IR option, rates would be determined on a cost of service basis for 2019, and adjusted mechanistically for the next four years through a price cap adjustment based on inflation and the OEB's assessment of Energy+'s efficiency.

The following parties were granted intervenor status in this proceeding:

- Brantford Power Inc. (BPI)
- Consumers Council of Canada (CCC)
- Hydro One Networks Inc. (Hydro One)
- School Energy Coalition (SEC)
- Toyota Motor Manufacturing Canada Inc. (TMMC)
- Vulnerable Energy Consumers Coalition (VECC)

[1] Decision and Order, EB-2014-0377/EB-2014-0217/EB-2014-0223, December 17, 2014.
[2] Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: a Performance Based Approach, October 18, 2012
[3] OEB Handbook for Utility Rate Applications, October 13, 2016.

Energy+ and the intervenors[4] participated in a settlement conference and filed a partial settlement proposal with the OEB on December 12, 2018.

Energy+, CCC, Hydro One, SEC, TMMC and VECC (the Parties) reached a complete or partial settlement on the following issues of the OEB-approved Issues List:

> 1.1 Capital – The Parties agreed to a net reduction of $300,000 in the 2019 proposed capital additions, which results in total capital additions of $11,378,277 for 2019. The Parties also agreed to Energy+'s request to withdraw its 2020 Advanced Capital Module funding for the Garden Avenue facility, which will be a shared facility with BPI. It was also agreed that Energy+ shall withdraw its proposal to dispose of the $402,807 gain included in Account 1508 arising from the sale of the Dundas Street property.[5]
>
> 1.2 Operations, Maintenance and Administration (OM&A) – The Parties agreed to reduce the proposed OM&A expenses in the 2019 test year by $170,000 to $18,453,358.[6]
>
> 2.1 & 2.2 Revenue Requirement – The Parties agreed to an increase of $100,000 in "other revenue" and agreed to a base revenue requirement of $34,327,788 for the 2019 test year.[7]
>
> 3.1 Load Forecast – The Parties agreed to a load forecast of 1,653,951,480 kWh and a customer number forecast of 82,897 for the 2019 test year.[8]
>
> 4.1 Accounting Changes – The Parties accepted the accounting changes and impacts proposed by Energy+.[9]
>
> 4.2 Deferral and Variance Accounts – The Parties agreed to Energy+'s proposed disposition of the Group 1 Deferral and Variance Accounts on a harmonized basis.[10]
>
> 5.1 Effective Date – The Parties agreed to an effective date of January 1, 2019.[11]

[4] BPI did not participate the settlement conference.
[5] Settlement Proposal, pp. 16-17.
[6] *Ibid.* page 20.
[7] *Ibid.* page 11.
[8] *Ibid.* page 27.
[9] *Ibid.* page 34.
[10] *Ibid.* page 35.
[11] *Ibid.* page 39.

The OEB approves the partial settlement proposal as filed (copy attached as Schedule A). Given that the settlement proposal provided for an effective date of January 1, 2019, a forgone revenue rider should be calculated by Energy+ as part of the draft rate order process.

In this Decision and Order, the OEB made findings on the following unsettled issues:

> 1.1 Capital – Advanced Capital Module: The OEB approves the materiality and need for the Southworks facility but only approves $6.5 million for the project.
>
> 3.2 Cost Allocation: The OEB will not create a separate rate class for TMMC. The OEB finds that the costs of the two dedicated feeders net of capital contributions should be directly allocated to the Large Use class. Given the allocation of the dedicated feeders, the OEB agrees that TMMC's load should not be used to allocate the costs of underground conductors to the Large Use class. The OEB finds that the continuation of the pooled approach is appropriate for allocating meter costs, OM&A costs, bulk assets, poles, and underground conduits.
>
> 3.3 Rate Design, including Distribution Rate Harmonization: The OEB approves Energy+'s distribution rate harmonization proposal. The OEB finds that the fixed charge for the Large Use class shall remain at $8,976.07.
>
> 3.4 Residential Rate Design: The OEB approves Energy+'s residential rate mitigation proposal.
>
> 3.5 Retail Transmission Service Rates (RTSRs) and Low Voltage (LV) Rate: The OEB approves Energy+'s proposal to harmonize RTSRs. The OEB finds that Energy+ should assess LV charges to embedded distributors in circumstances where Energy+ does not have a reciprocal arrangement with a host distributor where Energy + is an embedded distributor.
>
> 3.6 Gross Load Billing for Retail Transmission Service Rates: The OEB approves Energy+'s proposal to bill the Retail Transmission Rate – Line and Transformation Connection service charge on a gross load billing basis to customers with load displacement generation.
>
> 3.7 Standby Charge: The OEB declines Energy+'s proposal for a standby charge at this time.
>
> 4.2 Group 2 Deferral and Variance Accounts: The OEB approves the proposed disposition of the Lost Revenue Adjustment Mechanism variance account. The

OEB accepts Energy+’s proposal to dispose Group 2 DVA balances on a harmonized basis.

3.1 Load Forecast: The OEB directs Energy+ to remove the load adjustments to the Large Use class given the OEB’s decision on the standby charge proposal.

2 THE PROCESS

Energy+ filed its application on April 30, 2018 for 2019 rates. The OEB issued a Notice of Application on May 28, 2018.

The OEB held a community meeting on July 11, 2018 where OEB staff and Energy+ made presentations. A summary of the community meeting was posted on the record of this proceeding. The customers who attended the community meeting asked questions and expressed concerns about the amalgamation of the former CND Hydro and BCP, rate harmonization and bill impacts, standby charge, and new office buildings.

The OEB issued Procedural Order No. 1 on July 26, 2018 with a timetable for a written discovery process, the filing and discovery of expert evidence and a settlement conference. On October 31, 2018, the OEB issued its decision approving a final Issues List. A settlement conference was held on November 7, 8 and 9, 2018.

The Parties filed a partial settlement proposal with the OEB on December 12, 2018. OEB staff was not a party to the settlement proposal, but participated in the settlement conference in accordance with the role of OEB staff set out in the OEB's *Practice Direction on Settlement Conferences*. OEB staff filed its submission regarding the partial settlement proposal on December 19, 2018.

A technical conference was held on January 23, 2019 and an oral hearing took place on March 7 and 8, 2019. Energy+ filed its argument-in-chief on March 15, 2019. OEB staff, CCC, Hydro One, SEC, TMMC and VECC filed written submissions and reply submissions with respect to the unsettled issues. Energy+ filed its reply argument on April 23, 2019.

3 DECISION ON THE UNSETTLED ISSUES

3.1 Capital Expenditures – Advanced Capital Module

The Parties reached an agreement on all aspects of Issue 1.1 (Capital Expenditures) in the settlement proposal with the exception of Energy+'s request for an Advanced Capital Module (ACM) related to a proposed $8.1 million capital expenditure to renovate and convert an existing heritage building in downtown Cambridge (Southworks) into an administrative office building. In 2016, Energy+ was approached by a developer of a mixed-use project in downtown Cambridge (known as the Gaslight District). Energy+ acquired approximately 21,500 square feet of space in the existing building for $1 under the condition that Energy+ would undertake renovations to convert it into suitable office space. Energy+ plans to complete the proposed renovations in 2021 and expects the Southworks facility to be ready for occupancy in 2022.[12]

Centralizing all administrative employees in the Southworks facility is part of Energy+'s overall facilities plan (Facilities Plan). The Facilities Plan also includes sharing a new building on Garden Avenue with BPI as an operations centre for Energy+ to serve the BCP service territory, renovating the existing building on Bishop Street into an operations centre to serve the CND Hydro service territory, selling the existing property at Dundas Street, and terminating the lease of the Thompson Drive facility.[13] The ACM request for the Southworks facility is the only unsettled capital expenditure item that needs to be determined in this proceeding.

The OEB's ACM Report[14] provides an electricity distributor with an approach to identify and pre-test, as part of the rebasing application, qualifying discrete capital projects that are scheduled to go into service during the subsequent Price Cap incentive rate-setting (IR) term. The nature, need and prudence for the ACM project will be determined in the cost of service application. The timing and actual amount of rate riders used to recover the costs of an ACM project will be determined in the subsequent Price Cap IR application for the year in which the project comes into service.

[12] Oral Hearing Transcript, March 7, 2019, page 55, line 2.
[13] Energy+ Update to Evidence, December 13, 2018, page 4 to 7.
[14] EB-2014-0219, *Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module,* September 18, 2014 (ACM Report).

The ACM Report set out three criteria that a proposed ACM project must meet: materiality, need and prudence.[15] The ACM Supplemental Report[16] made changes to the OEB-defined materiality threshold.

OEB staff supported the proposed Southworks facility and submitted that the project meets the requirements of an ACM. OEB staff also noted that the ACM Report requires distributors to explain and justify any changes in project costs in the subsequent Price Cap IR application.[17] CCC and SEC concluded that Energy+ has not demonstrated that the Southworks facility is prudent, and submitted that the OEB should deny the ACM but allow Energy+ to apply again once it has an appropriate assessment to justify that the Southworks facility is the best option for an administrative building in Cambridge.[18] VECC stated that the Southworks facility does not meet the test of prudence and submitted two options for the OEB to consider: to deny the ACM proposal until such time as the major uncertainties are better understood or to cap the amount of the project costs that Energy+ can recover through rates at $8.1 million.[19]

The Parties made submissions with respect to each of the ACM criteria.

<u>Materiality</u>

No party had concerns with respect to the evidence that the Southworks facility meets the materiality requirement of the ACM criteria. OEB staff agreed with Energy+'s calculation of the materiality threshold and submitted that the proposed capital expenditure of $8.1 million falls within the eligible incremental capital envelope available to Energy+.[20]

<u>Need</u>

In order to obtain approval for an ACM in a cost of service application, a distributor must demonstrate that the proposal is a discrete and distinct project, unrelated to any recurring capital projects. In this application, no party argued that Energy+ failed to demonstrate that the proposed Southworks facility is a discrete project.

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[15] ACM Report, *op. cit*., page 17.
[16] EB-2014-0219, *Report of the Board on* New Policy Options for the Funding of Capital Investments: Supplemental Report, January 22, 2016 (ACM Supplemental Report).
[17] OEB Staff Submission, page 10.
[18] CCC Submission, page 5. SEC Submission, paragraph 2.
[19] VECC Submission, page 13.
[20] OEB Staff Submission, page 6.

Energy+ currently operates out of three facilities: Bishop Street, Thompson Drive and Dundas Street. The proposed Facilities Plan will increase the existing 72,630 square feet operation and administrative space to 88,247 square feet.

Energy+ identified the following evidence to support the need for the Southworks facility[21]:

- The existing facilities were constructed in the 1980's and the utility and industry had undergone significant change since that time
- The growth in business and the increasing number of full-time employees have resulted in insufficient office space
- The acquisition of BCP resulted in the need for consolidation of administrative staff to achieve OM&A cost efficiencies

OEB staff and SEC supported Energy+'s position that the Southworks facility is needed.[22]

VECC commented on three aspects of the proposed facility that it considered unusual[23]:

- Energy+ will separate its administrative functions from operations
- Energy+ proposed a 50% increase in administrative space compared to an 8% increase in operations space when the total number of full-time employees (administration and operations) has declined from 150 in 2014 to 135 for 2019
- The Southworks facility is part of a larger property development plan such that Energy+ will likely take on a number of risks and potential liabilities associated with the larger plan

Energy+ responded that it has to serve multiple service areas after the acquisition of BCP, such that the separation of administrative and operational functions is not unusual and that the proposed Southworks facility was by far the most cost effective solution. Energy+ also referred to the other advantages of this approach, including increased

[21] Energy+, Argument-In-Chief, page 8.
[22] OEB Staff Submission, pp 6-7. SEC Submission, paragraph 6.
[23] VECC Submission, pp. 3-4.

efficiencies of consolidating administrative staff and the flexibility of selling or leasing this asset if it was no longer required in the future.[24]

In response to VECC's comment on the proposed 50% increase to administrative space, Energy+ stated that the recommended space for the former CND Hydro was 102,762 square feet. With a proposed Facilities Plan of 88,247 square feet to accommodate the needs of both the former CND Hydro and BCP employees, Energy+ submitted that the proposed plan is modest.[25]

Energy+ asserted that the proposed Southworks facility was chosen after a five year process of exploring a wide range of different options, and the decision is a right sized and low cost solution to meet Energy+'s specific needs.[26]

Prudence

Energy+ indicated that it had completed a multi-year review of various alternatives since 2013, including renovating/rebuilding the Bishop Street facility, purchasing/renovating alternative facilities, leasing alternative facilities and constructing new facilities.[27] Energy+ assessed the options and concluded that the Southworks facility is preferred because the other options were either unfeasible or not cost efficient.[28]

OEB staff supported Energy+'s proposal and submitted that the Southworks facility meets the prudence test. OEB staff noted that Energy+ reviewed various options with a cost range of $28 million to $32 million and determined that the Southworks option is the most cost-effective one. With respect to the benchmarking comparison, OEB staff noted that Energy+'s comprehensive Facilities Plan cost is not excessive as it results in the lowest square foot per full time equivalent (FTE) employee, and the cost of $164.32 per square foot is the second lowest among all comparators. OEB staff prepared a comparison with two other administrative office buildings approved in other OEB decisions[29] with the Southworks facility. In recognition of certain limitations in the comparison, OEB staff submitted that the proposed capital cost per square foot for the

[24] Energy+ Reply Submission, page 7.
[25] *Ibid*.
[26] *Ibid*.
[27] Energy+, Argument-In-Chief, paragraph 29.
[28] Energy+, Argument-In-Chief, page 12.
[29] PowerStream (now part of Alectra) EB-2008-0244. Enersource (now part of Alectra) EB-2012-0033.

Southworks facility is comparable to similar investments that have been approved by the OEB.[30]

SEC submitted that the additional benchmarking information provided by OEB staff shows that costs for Southworks are significantly higher than similar projects on a cost per square foot basis, such that the OEB should reject the Southworks project.[31] Energy+ responded that SEC failed to account for known inflationary cost increases when comparing the Southworks cost directly with the PowerStream and Enersource projects. Energy+ summarized the OEB published inflation factors for the period of 2008 to 2017 in its reply submission.[32]

CCC, SEC and VECC expressed the following concerns with respect to the prudence of the Southworks facility:

- **Cost Estimate** – The accuracy/certainty of the Class C cost estimate (which includes +/- 20% uncertainty) of $8.1 million, which is an increase of 62% over the original cost estimate of $5 million.[33]

- **Alternative Analysis –** Energy+ provided no evidence to support the assertion that the Southworks facility was the best option for a dedicated administrative facility.[34] VECC argued that no evidence was provided to understand the comparative value of leasing office space rather than building or renovating.[35] SEC stated that Energy+ did not retain a real estate professional to look at other options for a purely administrative building, either to purchase or lease.[36] VECC submitted that it is not evident that the Southworks facility is the least cost solution because Energy+ appears to overestimate the soft costs of acquiring a single building in an industrial park or underestimate the soft costs of the Southworks facility. VECC also noted that the $150,000 annual parking cost included in OM&A is not considered in comparing capital costs.[37]

[30] OEB Staff Submission, pp. 9-10.
[31] SEC Reply Submission, paragraph 2.
[32] Energy+ Reply Submission, pp. 10-11.
[33] CCC Submission, page 2. SEC Submission, paragraph 10. VECC Submission, paragraph 2.7.
[34] CCC Submission, page 4. SEC Submission, paragraph 11-12. VECC Submission, paragraph 2.23-2.24.
[35] VECC Submission, paragraph 2.23
[36] SEC Submission, paragraph 11.
[37] VECC Submission, paragraph 2.15-2.20.

- **Benchmarking Comparison –** SEC noted that when the cost of renovating the existing Bishop Street and Garden Street facilities is removed from the Facilities Plan, the cost per square foot of the Southworks facility is significantly higher ($370 per square foot) than similar projects undertaken by other distributors.[38] VECC submitted that the examples of the two highest figures (Waterloo North Hydro Inc. and PUC Distribution Inc.) are considerably in the past and no context was provided.[39]

To respond to CCC, SEC and VECC's concerns over the 62% increase in the cost estimate, Energy+ stated the following drivers for the changes in costs[40]:

- Due diligence on the existing building and site has been completed
- Environmental due diligence has been completed and the mitigation solution is known and specified with a much more accurate cost
- The current Class C estimate is much more accurate based on a 30% completed design

Energy+ asserted that the proposed $8.1 million cost estimate is the most up-to-date information and by-far the most cost efficient option. The budget includes a contingency of $400,000 and Energy+ intends to complete the project within the budget. Energy+ also noted that concerns about uncertainty in cost forecast have been anticipated and are addressed by the ACM policy. Energy+ agrees with OEB staff that distributors (including Energy+) are obligated to explain and justify any changes in project costs when they apply for approval of actual costs and the establishment of rate riders during the subsequent Price Cap IR term.[41]

To further address the concerns about prudence related to the $8.1 million cost estimate, Energy+ referred to statements articulated by the Supreme Court of Canada in *Ontario (Energy Board) v. Ontario Power Generation* and asserted that Energy+'s decision to proceed with the Southworks facility was prudent at the time the decision was made.[42]

[38] CCC Submission, page 4. SEC Submissions, paragraph 13-14.
[39] VECC Submission, paragraph 2.14.
[40] Energy+ Reply Submission, pp. 12-13.
[41] Energy+ Reply Submission, pp. 13-14.
[42] Energy+ Reply Submission, pp. 17-18.

In addressing the concern over the lack of a direct comparison of leasing an administrative space against the proposed Southworks facility, Energy+ referred to the June 2015 CBRE Market Overview filed as part of the Facilities Plan and stated that no existing buildings were identified as appropriate and that the cost associated with constructing a new building was significant. Energy+ also listed three sites that were identified as available for lease in the Cambridge area and concluded that including leasehold improvement costs to make the space suitable, the cost of leasing an administrative space was more expensive than the costs of ownership.[43]

To address the concern that the $370 per square foot cost estimate is significantly higher than other comparators, Energy+ stated that inflationary cost increases and utilization (square foot per FTE) should also be factored in when using the cost per square foot benchmark.[44] Energy+ reviewed the OEB published inflation factors for the period of 2008 to 2017 and supported OEB staff's administrative building comparison of Southworks with the PowerStream and Enersource projects.[45] Energy+ asserted that the ability to right size the administrative space to match Energy+'s needs was a unique feature of the Southworks arrangement that made it attractive to Energy+ management.[46]

Energy+ did not agree with CCC, SEC and VECC's suggestion that the OEB should reject the ACM proposal and request Energy+ to file additional evidence in a subsequent ICM application. Energy+ stated that the suggestion would greatly undermine the regulatory efficiency that the ACM policy framework was expressly intended to facilitate.[47]

SEC also expressed a concern that Energy+ did not select the construction management or architectural firm by way of a competitive procurement process and that the firm was chosen because it is being used by the developer in the larger development process.[48] Energy+ responded that it has been working closely with this firm, Melloul Blamey Construction, to assess its facilities needs since 2013 and the firm has developed a deep understanding of Energy+'s needs and preferences.[49]

[43] Energy+ Reply Submission, pp. 15-17.
[44] Energy+ Reply Submission, page 10.
[45] Energy+ Reply Submission, paragraph 32-33.
[46] Energy+ Reply Submission, paragraph 38.
[47] Energy+ Reply Submission, paragraph 90.
[48] SEC Submission, paragraph 15.
[49] Energy+ Reply Submission, paragraph 93.

Findings

The OEB finds that the materiality criterion for the ACM is met based on the calculated threshold and the estimated cost of the Southworks facility. The OEB also finds that the need for the facility has been demonstrated based on the increasing number of employees, the acquisition of BCP and the efficiencies of consolidating the administrative staff.

The OEB finds there is insufficient evidence to approve a capital budget of $8.1 million for the Southworks facility as prudent. This finding is reinforced by the comparison to similar facilities developed by other distributors. Energy+ compared the estimated cost of the Southworks facility with the cost of facilities developed by other distributors which had been designed to accommodate a combination of administrative and operations staff. However, the Southworks facility is only intended to accommodate administrative staff with different requirements. The comparison provided by Energy+ showed that the estimated cost for the Southworks facility (in terms of dollars per square foot) is significantly higher than the comparators (29% to 171% higher).

The comparison provided by OEB staff in its final submission was more relevant as it used administration only facilities as comparators. This comparison still showed that the estimated Southworks cost is higher than the comparators, but by a narrower margin (23% to 62% higher). The OEB staff comparison also addresses concerns raised in the final submissions about the necessity to account for inflation as the comparators' costs were estimated in 2008 and 2012. As well, there are costs that are not included in the Southworks capital cost estimate which may have been included in the other cases (e.g. parking costs, other "soft costs", etc.). If the costs for the two comparators presented in the OEB staff submission are adjusted for inflation,[50] the cost range of these facilities would be approximately between $250 and $350 per square foot. If one is to consider the average of these costs ($300 per square foot) and apply this average cost to the area to be developed at the Southworks facility (21,892 square feet), the cost estimate would be $6.5 million compared to Energy+'s current estimate of $8.1 million.

The OEB also notes that only a small portion of the Southworks construction contract (construction management and architectural components, representing about 13% of the total estimated cost) has been awarded. The remaining 87% is yet to be awarded based on a competitive tender process.[51] This presents a significant uncertainty

[50] Using OEB's IRM inflationary factors.
[51] Oral Hearing Transcript Vol.1, page 65.

regarding the reliability of the estimated cost of the facility and also raises questions as to whether the $400,000 project contingency is adequate.

The OEB is also concerned about the quality of Energy+'s cost estimates. The initial estimate of $5.0 million was presented as a Class D estimate with an accuracy of ± 30%. The revised estimate of $8.1 million is presented as a Class C estimate with an accuracy of ± 20%. Given the amount of work that Energy+ did to improve the accuracy of the cost estimate (building and site due diligence, environmental due diligence, 30% completed design, etc.), there does not appear to be a corresponding improvement in the accuracy of the cost estimate in spite of the 62% increase in the actual estimate.

Furthermore, the initial $5.0 million cost estimate included a contingency of $125,000.[52] It seems counter-intuitive that the project contingency significantly increased (to $400,000) as the accuracy of the cost estimate presumably improved.

The OEB finds that Energy+ has not provided sufficient evidence in support of the reasonableness of its current cost estimate for the Southworks facility. While acknowledging the need for the facility, the OEB will only approve $6.5 million for the ACM. This funding envelope is based on reasonable comparisons and the history of the development of the Energy+ estimates. Energy+ will have the opportunity to address any deviation from this amount in its subsequent Price Cap IR application for the year in which the project comes into service.

3.2 Cost Allocation

Large Use Class Cost Allocation

Energy+ has two Large Use customers in its former CND Hydro service area. One of the customers, TMMC, is presently served by two feeders that are dedicated to its use, and directly connected to Hydro One's Preston Transformer Station (Preston TS).

TMMC installed an on-site generation facility consisting of two 4.6 MW combined heat and power (CHP) units. It uses the steam from this facility as process heat, as well as for heating and cooling its facilities. TMMC has the capability to operate the units separately, and typically operates both units at full capacity when running production in

[52] Energy+ response to Staff Interrogatories, Appendix 2-Staff-12-i).

the factory, and one unit at other times. It also uses this capability to take one unit at a time out for service during its lower load times.

The Parties had different views on whether both TMMC and the other Large Use customer (not identified) should be served in a single Large Use rate class or should each customer be in its own rate class. The Parties also expressed different views on whether there should be direct allocation of the costs of the assets used exclusively by TMMC and if so, whether direct allocation should be utilized for a single customer or the entire rate class. Finally, the Parties made submissions with respect to whether TMMC's usage should be factored into the allocation of underground conduit and bulk distribution assets.

Number of Large Use Rate Classes

Energy+ proposed that a single Large Use rate class is appropriate, rather than two separate Large Use classes.[53] In CND Hydro's last cost of service application, its rates were approved on the basis of two customers in the Large Use rate class.[54] TMMC filed evidence supporting its view that it is sufficiently different from the other Large Use customer that it requires a separate rate class based on the principle of cost causation.[55] To identify the distinguishing characteristics of the proposed separate rate class, TMMC relied on four criteria that it submitted necessitate the need for a second rate class:[56]

- The operation of a Load Displacement Generation (LDG) facility
- Load in excess of 20 MW
- Primary substation service
- Dedicated distribution assets (with the exception of poles)

In support of a rate class dedicated to TMMC, TMMC referenced two Ontario Local Distribution Companies (LDCs) with rate classes dedicated to Large Use customers served with dedicated feeders: EnWin Utilities Ltd. (EnWin Utilities) and Alectra Utilities Corporation (Alectra Utilities).

[53] Argument-in-Chief, page 20.
[54] EB-2013-0116.
[55] TMMC updated evidence of Mr. Pollock filed February 15, 2019 (Updated Pollock Evidence), pp. 9-10.
[56] Updated Pollock Evidence, *op. cit.*, pp. 9-10.

OEB staff noted that the decision to create a new rate class requires balancing the number of rate classes that would be created and the level of cross subsidization within a class.

OEB staff submitted that some of the defining characteristics of TMMC's rate class, including the LDG facility and customer size, are not defining characteristics in the examples cited by TMMC. What is a common characteristic is the use of dedicated feeders to the customers.[57]

OEB staff also noted that the separate classes in EnWin were created in 2002 which predates the OEB's current cost allocation policy.[58] With respect to Alectra's Large Use (2) rate class, OEB staff noted the existence of at least five customers in each class following the subdivision of the Large Use class.[59]

OEB staff expressed concern that, if specific/unique criteria are a basis for creating a separate rate class for an individual customer, such an approach could give rise to numerous more classes with unique characteristics. OEB staff submitted that a single rate class for all Large Use customers is appropriate in this case.[60]

VECC submitted that the only relevant factor to consider is the existence and cost allocation treatment of the dedicated feeders. VECC reasoned that the cost allocation study proposed by TMMC was not meant to capture the cost of providing both Supplementary[61] and Standby Service[62], and therefore the fact that TMMC operates a LDG facility should have no impact on the decision as to whether one or two Large Use classes are required. VECC believed the fact that TMMC is larger than the other Large Use customer, and that some costs are fixed on a per customer basis, is already recognized in the OEB's cost allocation methodology through the use of both customer count and volume as allocators where appropriate.

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[57] OEB Staff Submission, page 17.
[58] EB-2007-0667, Report of the Board: Application of Cost Allocation for Electricity Distributors, November 28, 2007.
[59] OEB Staff Submission, page 18.
[60] OEB Staff Submission, pp. 18-19.
[61] Updated Pollock Evidence, page 22. TMMC defines Supplementary Service as "the regular distribution service provided to a customer for load that is not otherwise supplied from the customer's LDG facilities."
[62] Updated Pollock Evidence, page 25. TMMC defines Standby Service as "the additional delivery services required when TMMC's LDG sustains an outage and there is a net increase in TMMC's peak demand as a result of the outage."

SEC submitted that if cost allocation is done correctly, there should be no impact on any other customer class.[63]

TMMC stated that OEB staff's concern about a proliferation of separate customer classes is misplaced and unsupported. TMMC noted that it receives primary substation service whereas the other Large Use customer receives primary distribution service, such that the costs of providing service to TMMC comprise a unique and separate cost pool, and the number of customers who comprise that cost pool should not determine the question of whether a separate rate class is warranted.[64]

Demand Allocators

VECC noted that when performing a cost allocation study based on two Large Use classes, neither Energy+ nor TMMC's witness, Jeffrey Pollock (Mr. Pollock), made any allowance for the diversity between the two customers that is inherent in the four non-coincident peak (NCP) demand allocation factor. VECC submitted that, if the OEB decides to create two Large Use classes, then it should also direct Energy+ to adjust the 4NCP demand allocation factors used in the cost allocation methodology to account for this loss in diversity.[65] Energy+ agreed with VECC's position.[66]

Direct Allocation in respect of TMMC's Usage

TMMC's evidence refers to allocations and rates applicable specifically to a customer, rather than to the rate class, and this is evident in the derivation of base and standby rates which would specifically apply to TMMC's load.[67] Energy+ on the other hand is allocating all costs to the applicable rate class, Large Use in this case, not to specific customers.

OEB staff submitted that direct allocation should be applied to a rate class with respect to assets used exclusively by individual rate classes and that, since customers in the same class do not pay individualized rates, it would not be sensible to perform direct allocation to customers.[68]

[63] SEC Submission, page 18.
[64] TMMC Reply Submission, page 11.
[65] VECC Submission, page 21.
[66] Energy+ Reply Submission, paragraph 136.
[67] Updated Pollock Evidence, *op. cit.*, Schedules JP13, JP14.
[68] OEB Staff Submission, page 19.

Energy+'s current proposal is to not perform a direct allocation of assets,[69] although in its argument in chief, Energy+ indicated that:

> Energy+ is not opposed to utilizing direct allocation where the facts support such an approach. Energy+ believes that there is sufficient and credible evidence available to justify the direct allocation of the dedicated TMMC feeder costs to the Large User customer class, and that such direct allocation should also account for the capital contribution paid by TMMC in support of those feeder costs.[70]

While not opposed to the direct allocation of feeder costs, Energy+ stated that no other costs should be directly allocated to the Large Use customer class.[71]

TMMC proposed a direct allocation to TMMC of all assets used by TMMC, with the exception of poles,[72] namely the costs associated with the dedicated feeder, net of capital contributions.

OEB staff agreed with TMMC that direct allocation with respect to costs associated with the dedicated feeder, net of capital contributions, is appropriate.[73]

VECC argued that TMMC's circumstances are unique in that the feeders are dedicated, but the poles are not. VECC noted that the OEB's direction on the use of direct allocation does not make specific reference to the Uniform System of Accounts (USoA) accounts or services/functions, but rather uses the term "distribution facility". It therefore reasoned that interpretation and judgement is involved in determining whether the requirements for direct allocation are met. VECC noted that the costs from USoA 1835 (overhead conductor) directly allocated to TMMC do not include the cost of the fibre optic cable that is owned by Energy+ between Preston TS and TMMC.

VECC was not opposed to the use of direct allocation in the case of feeders. However, should the OEB decide to adopt direct allocation for these feeders, VECC submitted that it should indicate that it is based on the specific circumstances involved and should not be considered as generic precedent for other distributors.

[69] Response to TCQ-VECC-76.
[70] Energy+ Argument-In-Chief, page 20.
[71] Energy+ Argument-In-Chief, page 20.
[72] Updated Pollock Evidence, *op. cit.,* page 8.
[73] OEB Staff Submission, page 19.

SEC submitted that the two feeders which serve TMMC with the exception of poles should be directly allocated to the Large Use or a TMMC specific class.[74]

Allocation of Meter Costs and OM&A Costs

Meter Costs

TMMC proposed to directly allocate meter costs to the rate class that includes TMMC.

Energy+ agreed with VECC that meter costs should not be directly allocated to TMMC given that these are not significant distribution facilities, and given that the cost allocation model already addresses differences in meter and meter reading costs.[75]

TMMC responded that its meter costs are discrete, dedicated, identifiable and easily tracked to TMMC and should be directly assigned.[76]

OM&A Costs

TMMC proposed that OM&A costs should be directly allocated to the Large Use class.

VECC noted that Energy+ has indicated that its estimate of OM&A costs associated with the feeders has a fairly high margin for error. SEC submitted that given the uncertainty around the values, OM&A costs should not be directly allocated.[77]

VECC reasoned that in light of the uncertainties regarding the costs associated with the directly allocated assets, the OEB should revise the revenue to cost (R/C) ratio range for the Large Use class that has directly allocated costs from 85%-115% to 80%-120% (similar to that used for the General Service classes) in recognition of the increased cost uncertainty.[78]

Energy+ agreed with SEC that OM&A costs should not be directly allocated to TMMC.

TMMC stated that it would accept an allocation of pooled OM&A expenses, but submitted that a revenue to cost ratio of 115% (as it proposed) would be sufficient to offset cost uncertainties.[79]

Allocation of Common Assets with respect to TMMC's Usage

[74] SEC Submission, page 15.
[75] Energy+ Reply Submission, pp. 25-26.
[76] TMMC Reply Submission, page 4.
[77] SEC Submission, page 16.
[78] VECC Submission, page 19.
[79] TMMC Reply Submission, page 5.

Bulk Assets

Customers of Energy+ are served by seven transformer stations which step power down from transmission voltages to distribution voltages. Five of these are owned by Hydro One Networks Inc. (Hydro One) and the costs are recovered from all Hydro One customers. One transformer station is owned solely by Energy+ and one transformer station is jointly owned by Energy+ and BPI. Energy+'s investment in the transformer stations is treated in the cost allocation model as bulk assets.

Energy+ submitted that bulk distribution costs should be allocated to the Large Use rate class on the basis of the full rate class load including TMMC, as these assets are normally allocated to all customers regardless of each customer's individual service connection.[80]

TMMC was opposed to allocating any proportion of Energy+'s bulk assets to TMMC as it does not use nor have access to any of Energy+'s transformer stations.[81] TMMC also noted that it is served exclusively by a Hydro One transformation facility, Preston TS. When asked why TMMC should be excused from paying a share of the bulk transformer stations, while other customers are not excused from paying for Hydro One transformer stations, TMMC's witness stated that he had not addressed the allocation of the retail transmission service rates (RTSRs) charges, but only the allocation of bulk facilities.[82]

OEB staff noted that customers do not have a choice whether they are connected to an LDC owned transformer station, or a transmission company owned transformer station, and all customers normally pay for both bulk assets and RTSRs. OEB staff submitted that the Large Use rate class should be no different.[83]

VECC stated that it is reasonable to take either a specific assets approach where rate classes are allocated costs on the basis of specific assets used, or a "services" or "pooling" approach, where all costs of a given service are pooled and allocated to all customers which use those services. However, the approach should be consistently applied. Therefore, if Energy+'s bulk facilities are not to be allocated to rate classes that do not make use of these facilities, then RTSRs should be adjusted to exclude loads in each customer class served from Energy+'s bulk facilities. However, VECC noted an issue in that Energy+'s distribution system is dynamic and constantly changing.

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80 Argument-in-Chief, page 20-21.
81 Updated Pollock Evidence, *op. cit.*, page 8.
82 Oral Hearing, Day 2, page 65.
83 OEB Staff Submission, page 20.

VECC submitted that allocating the costs of bulk facilities (and establishing RTSRs) using a “pooling approach” that includes all customer’s/customer classes’ loads as proposed by Energy+ is a more practical and fair approach.[84]

SEC noted that to exclude TMMC from being allocated bulk costs would reflect a cross-subsidization as RTSRs are allocated to all customers regardless of which transformer station serves them.[85]

TMMC argued that it does not allocate bulk assets because it is directly connected to a Hydro One transformer station, and not an Energy+ station. With respect to the positions of Energy+, SEC, and VECC on adjusting RTSRs for consistency, TMMC explained that RTSRs related issues are complex issues that have not been well-litigated, if at all in this proceeding.[86]

Energy+ agreed with VECC that if its proposal for cost allocation of bulk facilities is not approved, then the load in the RTSRs models should be adjusted to exclude the portion of load served from Energy+’s bulk facilities for each customer class. Energy+ noted this would be a time consuming and cumbersome process, and is unsure whether it could actually be accomplished to a reliable degree of accuracy.[87]

Poles

Energy+ proposed that both overhead and underground facilities including poles, conduit, and conductor be allocated to the Large Use rate class on the basis of the full rate class load including TMMC, whether or not they are used by TMMC. In the event that a direct allocation of the feeder is performed, then Energy+ proposed that only underground conduits and poles be allocated to the Large Use rate class. This is consistent with the treatment of all other rate classes which are allocated costs of both overhead and underground assets regardless of the specific assets used to provide service.[88]

TMMC proposed that allocation of the cost of poles based on its demand is appropriate given that it makes use of poles that are part of the pooled assets of Energy+, i.e. they

[84] VECC Submission, page 23.
[85] SEC Submission, page 17.
[86] TMMC Reply Submission, page 9.
[87] Energy+ Reply Submission, pp. 42-43.
[88] Argument-in-Chief, page 21.

provide service to TMMC as well as other customers by holding both TMMC's dedicated feeders as well as feeders serving other customers.[89]

As confirmed on cross examination,[90] both TMMC and the other Large Use customer make use of poles, as both are served by overhead feeders.

Underground Assets

TMMC reasoned that it should not have to pay for any underground assets including feeders or conduit because it does not use these assets.[91] SEC drew parallels between the function of poles and underground conduit and reasoned that poles and conduit serve the same function in a distribution system.[92] SEC noted that the allocator for poles consists of the loads of all customers using overhead or underground systems, and raised the concern that in fairness, if TMMC's proposal were to be adopted, customers who don't use poles shouldn't have to pay for poles.

OEB staff submitted that the use of overhead poles and underground conduit serve the same role in the system, i.e. to hold conductor, the selection of which is determined only based on whether the conductor is overhead or underground, a matter that is largely out of the control of the customer. Both of these assets are typically allocated to all customers on the basis of their usage and should be allocated to the Large Use rate class on the combined requirements of both Large Use customers.

OEB staff submitted that both overhead and underground conductors should be allocated to the Large Use rate class on the basis of the usage of the other (not TMMC) Large Use customer.

VECC supported Energy+'s proposal to allocate underground facilities to the Large Use rate class with respect to all class load as this would be consistent with a services or pooling approach. Alternatively, a "specific asset" approach could be used for all customers, but this would be problematic from a practical perspective, for example where utilities have two or more geographically separate service areas, requiring a cost allocation for each. VECC therefore submitted that the OEB should reaffirm the "pooling" approach to cost causality/cost allocation as used in the current version of the OEB's cost allocation model. [93]

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[89] Updated Pollock Evidence, *op. cit.*, page 8.
[90] Oral Hearing, Day 1, page 187.
[91] Updated Pollock Evidence, *op. cit.*, page 17.
[92] Oral Hearing, Day 2, page 61.
[93] VECC Submission, pages 24-25.

SEC submitted that, if the feeders are directly allocated, then underground conductors should not be allocated in respect of the same customer. However, underground conduits should not be excluded from allocation as they are the mirror service to poles, and poles are not directly assignable to TMMC. SEC submitted it is only appropriate to exclude an asset or expense if a similar service is being directly allocated to the customer class.[94]

VECC noted that the treatment of embedded distributors is the exception, and not the rule, and should not be used as a precedent for TMMC's exception from allocation of underground conduit. VECC viewed the fact that all of Energy+'s other end-use customer classes requiring primary service are allocated primary underground conduit as the more relevant precedent for the allocation of underground conduit to TMMC.[95]

TMMC argued that the capabilities of the OEB's cost allocation model, and difficulty of modelling, is not a sufficient reason to depart from cost causation when TMMC does not make use of any underground facilities. It noted that, in the Horizon case, underground facilities were excluded from allocation to the Large Use 2 rate class.[96] TMMC noted that if underground conduit and overhead poles and towers were functional equivalents, there would be no need to have separate overhead and underground accounts. It also noted that since TMMC does not require underground conductors, it does not require underground conduit.[97]

Energy+ agreed with all parties (except TMMC) that underground conduit should be allocated to all customers, including TMMC. It submitted that it is almost impossible to determine the assets used by each customer so the only fair and reasonable approach to allocate the underground conduit is based on a pooled approach.[98]

<u>Confidentiality</u>

As Energy+ proposed a single Large Use rate class for both customers and allocation of all costs, there is less concern with confidentiality of individual customer data and the proposed cost allocation model was filed on the public record without the need for redaction.[99]

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[94] SEC Submission, pp. 16-17.
[95] VECC Reply Submission, page 5.
[96] TMMC Reply Submission, page 7.
[97] TMMC Reply Submission, pp. 8-9.
[98] Energy+ Reply Submission, pp. 28-29.
[99] Response to TCQ-VECC-76.

TMMC had requested and been granted confidential treatment with respect to its load information.[100] In presenting its case, it has filed several cost allocation models, interrogatory responses, as well as its consultant's reports in confidence with redacted versions filed on the public record. At the oral hearing, TMMC agreed that its load data can be provided on the public record once aggregated or "rolled up" to an annualized level.[101]

OEB staff submitted that it should be possible to create a cost allocation model consistent with this submission which does not require confidential treatment.[102]

Findings

Number of Large Use Rate Classes

The OEB will not create a separate rate class for TMMC. The OEB agrees with OEB staff and VECC that the existence of the dedicated feeders serving TMMC is the only factor that may warrant consideration of a separate rate class. Neither the fact that TMMC operates an LDG facility, nor the difference in customer size, are determining factors in deciding whether a separate rate class is required. The OEB shares OEB staff's concern that creating rate classes defined by way of a single unique characteristic - in this case dedicated feeders - might unnecessarily complicate the cost allocation framework. Energy+ has also referenced concern about the additional costs in administering a separate rate class, confidentiality of customer information, as well challenges in dealing with any other future large user in Energy+'s service territory. The OEB does not find that the case for a separate rate class for TMMC has been sufficiently supported in this proceeding.

Demand Allocators

In light of the OEB's decision to deny TMMC's request for a separate rate class, an adjustment to demand allocation factors to account for a loss of diversity is not required.

Direct Allocation in respect of TMMC's Usage

The OEB finds that the costs of the two dedicated feeders net of capital contributions should be directly allocated to the Large Use class. The exclusive use test for this

[100] Procedural Order No. 3, October 5, 2018.
[101] Oral Hearing, day 2, page 10.
[102] OEB Staff Submission, page 20.

determination provided in OEB directions on cost allocation methodology has been met.[103] The OEB agrees with VECC that this determination is made on the basis of the specific circumstances of the use of the feeders rather than setting out a generic precedent for direct allocation. Given the allocation of the dedicated feeders, the OEB agrees that TMMC's load should not be used to allocate the costs of underground conductors to the Large Use class.

Allocation of Meter Costs and OM&A Costs

The OEB will not provide for the direct allocation of meter costs to the Large Use class. The OEB agrees with Energy+ and VECC that the meters are not a significant distribution facility, and that TMMC is not unique in having dedicated meters. The OEB also notes that the direct allocation of meter costs would require resort to underlying work orders or estimates as TMMC's meter costs are not recorded in a separate account or sub-account. This raises concerns about the practicality of TMMC's direct allocation proposal. The OEB will maintain the current approach to allocation of meter costs.

The OEB finds that direct allocation of the OM&A costs associated with the dedicated feeders is not an unreasonable proposal in theory. However, there are considerable uncertainties concerning the calculation of such directly allocated costs as there have been no time studies to validate either the OM&A estimates provided by both Energy+ and TMMC. The OEB declines to provide that the OM&A costs be directly allocated to the Large Use class.

Allocation of Common Assets with respect to TMMC's Usage

The direct allocation of the costs of specific assets based on use is in keeping with the application of the principle of cost causality. However, the principle of cost causality must also be applied in a manner that reflects fairness and consistency towards all customers. Customers do not have the choice where they obtain service connection and the quarantining of costs associated only with facilities used by TMMC, in the fashion urged by TMMC, would also require the calculation of RTSRs charges to exclude loads in each customer class served by Energy+'s bulk facilities. There is no certainty that these calculations could be done with accuracy and administrative convenience. The OEB finds that the pooling approach to the costs of bulk facilities is the appropriate methodology for allocating these costs.

[103] Board Directions on Cost Allocation Methodology, RP-2005-0317, page 31.

The OEB agrees with SEC that underground conduits and poles serve the same function. Once again, the important considerations of practicality and certainty make any exercise of direct allocation of poles and underground conduits to each customer class based on use a difficult proposition. The OEB finds that the continuation of the pooled approach is appropriate.

With respect to underground conductors, as noted previously, TMMC's load will be excluded from the calculation of the costs to be allocated to the Large Use class.

Confidentiality

As the OEB has declined to create a separate large user class for TMMC, the confidentiality concerns associated with the possible derivation of the total demand for both Large Use customers have been alleviated.

Embedded Distributor Cost Allocation

Embedded Distributor Cost Allocation

To allocate costs to embedded distributor classes, Energy+ proposed to use the direct allocation feature in the cost allocation model by entering information from Appendix 2-Q in Chapter 2 of the Filling Requirements,[104] which determines a percentage of the total Energy+ costs to be allocated to each embedded distributor.[105] The model then adds the appropriate administrative costs, an allocation of rate of return on rate base and payment in lieu of taxes.[106]

An alternative approach of allocating costs to embedded distributors as though they were general service customers- i.e. using the cost allocation model- was raised by VECC in the technical conference.[107]

In its decision dated March 4, 2019, the OEB determined that consideration of the alternative embedded distributor cost allocation methodology raised by VECC is out of

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[104] Ontario Energy Board *Filing Requirements For Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications- Chapter 2* (Filing Requirements).
[105] 7-VECC-47.
[106] VECC-TCQ-66.
[107] VECC-TCQ-69.

scope in this proceeding. The OEB requested the Parties to provide recommendations on how to address this issue on a going forward basis in their final submissions.[108]

VECC noted that the alternative approach is not a significant departure from previous OEB decisions and identified seven approved rate applications where Appendix 2-Q was not used for embedded distributor cost allocation.[109]

SEC noted that there is inconsistency regarding how host distributor costs are allocated to embedded distributors and submitted that the OEB should have a consistent treatment of the allocation methodology on a going forward basis.[110]

OEB staff noted that the current cost allocation methodology and model have the capability and adaptability to implement reasonable allocation proposals for embedded distributors. OEB staff submitted that this issue is applicable to many distributors and it can best be considered at the time of the OEB's next cost allocation policy review.[111]

Energy+ stated that it is aware of the broader policy implications that may arise from the inconsistent approaches used by distributors and it supports a policy review on a generic basis.[112]

Embedded Distributor Revenue to Cost Ratio

Energy+'s proposed cost allocation methodology results in four embedded distributor rate classes having a revenue to cost ratio of over 120%, and one embedded distributor having a revenue to cost ratio of under 80%.[113]

Energy+ proposed that the revenue to cost ratio for embedded distributors be set to 100%, which would be consistent with the treatment in the 2014 cost of service application / decision.[114]

OEB staff submitted that where the revenue to cost ratio is above the ceiling or below the floor, it should be set to the nearest boundary and that the applicable range for the embedded distributor rate class is 80% to 120%.

[108] EB-2018-0028, Decision on Embedded Distributor Cost Allocation, issued March 4, 2019.
[109] VECC Submission, paragraph 3.52.
[110] SEC Submission, paragraph 68.
[111] OEB Staff Supplementary Submission, page 3.
[112] Energy+ Reply Submission, paragraph 143.
[113] VECC-TCQ-76, Revenue Requirement Workform, Tab 11. Cost Allocation.
[114] Settlement Proposal, page 30.

Energy+ indicated it was open to the approach suggested by OEB staff and agreed there are merits in applying the same methodology to all rate classes for setting revenue to cost ratios.[115]

Findings

Embedded Distributor Cost Allocation

The OEB notes that the issue of possible full inclusion of embedded distributors in the cost allocation model, as raised by VECC was ruled out of scope on the basis of its timeliness in the progress of this proceeding. In its final argument, VECC referenced the cost of service applications of seven host distributors that have not used Appendix 2-Q to allocate costs to their embedded distributors.

While the OEB may issue some guidance in the future providing for consistent treatment of the allocation methodology on a going forward basis, at this time it is worth noting that there are a couple of approaches that could be, and have been, proposed by other distributors and considered by the OEB. The OEB expects that Energy+, in its next rebasing cost of service application, will address the option of full inclusion of embedded distributors in the cost allocation model including its congruence with existing OEB guidelines, instructions or previous OEB decisions.

Embedded Distributor Revenue to Cost Ratio

The OEB agrees with OEB staff that it would be preferable that revenue to cost ratios for embedded distributors be consistent with the OEB policy. This policy provides for the adjustment of outlier ratios to the nearest boundary for the rate class. Energy+ is directed to implement that adjustment for the embedded distribution class.

3.3 Rate Design

Rate Harmonization

Energy+ proposed harmonization of distribution rates for customers in the CND Hydro and BCP service territories based on its existing rate classes.[116] This harmonization

[115] Energy+ Reply Submission, paragraph 177.
[116] Energy+, Argument-In-Chief, paragraph 67.

plan includes distribution service charges, specific service charges, retail service charges, and loss adjustment factors.[117]

No party objected to the distribution rate harmonization proposal.

Findings

The OEB finds that Energy+'s distribution rate harmonization proposal is reasonable and directs its implementation.

Residential Rate Design

The total bill impacts for low volume residential customers are in the range of 12.2% to 13.3% for all scenarios that have been explored in this proceeding.[118] Energy+ proposed to mitigate the total bill impact on low volume residential customers by deferring the transition to a fully fixed monthly service charge for the residential class by one additional year to reduce the bill impact to less than 10%.[119]

OEB staff, CCC and VECC supported Energy+'s mitigation proposal.

Findings

The OEB finds that Energy+'s residential rate mitigation proposal is reasonable and directs its implementation.

Large Use Class Fixed Charge

Energy+ proposed to increase the fixed charge for the Large Use class to $9,210.42[120] from $8,976.07. The current fixed charge is already above the ceiling value established

[117] Energy+ Reply Submission, paragraph 145.
[118] Oral Hearing, March 7, 2019, Exhibit K1.6, Appendix A, Bill Impact Scenarios.
[119] Argument in Chief, March 15, 2019, paragraph 68.
[120] VECC-TCQ-76, RRWF tab 13.

by the minimum system with peak load carrying capacity adjustment in the cost allocation model.

In accordance with Section 2.8.1 of the Filling Requirements[121], OEB staff submitted that the fixed charge for the Large Use class should remain at the existing level of $8,976.07.[122]

TMMC also proposed to maintain the existing fixed charge for providing supplementary distribution service to TMMC.[123]

In its reply submission, Energy+ stated that it agrees with OEB staff and TMMC that the fixed charge for the Large Use class should remain at $8,976.07 and noted that the monthly variable charge will need to be revised accordingly to ensure that Energy+ receives the approved revenue requirement.[124]

Findings

The OEB finds that the fixed charge for the Large Use class shall remain at $8,976.07.

3.4 Retail Transmission Service Rates and Low Voltage Rates, including Gross Load Billing for RTSRs

Retail Transmission Service Rates

Energy+ proposed to harmonize the RTSRs for the CND Hydro and BCP service territories. Energy+ adjusted the billing demand by 74,376 kW for the Large Use class for determining RTSRs to account for the proposed gross load billing methodology. The proposed RTSRs apply to all customer classes with the exception of Hydro One No.2 embedded distributor class in the BCP service area.[125] Energy+ confirmed that it will

[121] Ontario Energy Board *Filing Requirements For Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications- Chapter 2.*
[122] OEB Staff Submission, page 23.
[123] TMMC Updated Evidence, dated February 15, 2019.
[124] Energy+ Reply Submission, paragraph 172.
[125] Energy+ Reply Submission, paragraph 179.

provide a revised RTSRs work form to reflect the updated demand for Hydro One No.1 for the BCP service territory as part of the draft rate order process.[126]

No party objected to Energy+'s proposal to harmonize the RTSRs. OEB staff noted that the adjustment of 74,376 kW on Large Use class billing demand would not be required if the OEB determines not to implement gross load billing for RTSRs in this proceeding.[127]

Findings

The OEB approves Energy+'s proposal to harmonize RTSR rates and directs its implementation.

Low Voltage Rates

Energy+ serves five embedded distributors, two in the former CND Hydro service territory, and three in the former BCP service territory. Energy+ proposes to maintain its present treatment of not applying Low Voltage (LV) charges to these customers.[128]

The specific circumstances around Energy+'s embedded distributors vary depending on the source of supply which Energy+ uses for each one. In one instance, Energy+ takes its supply from Hydro One as a sub transmission customer. For this feeder, Energy+ has an arrangement with Hydro One that Hydro One's sub transmission (ST) rates are charged based only on the power consumed by the connected Energy+ customers and that Energy+ reciprocate by not charging LV charges for the power delivered back to Hydro One.[129]

On a second feeder, Hydro One is embedded as a distinct customer of Energy+ in a distinct rate class. Also on this feeder, Energy+ is embedded in BPI. Energy+ pays LV charges to BPI in respect of both its own load and Hydro One's load.[130]

OEB staff noted that the payments a distributor makes to its host distributor, and recovers through LV charges, related to the same functions that it would normally

[126] Energy+ Reply Submission, paragraph 181.
[127] OEB Staff Submission, page 25.
[128] Oral Hearing, Day 1, page 141.
[129] Oral Hearing, Day 1, page 133.
[130] Oral Hearing, Day 1, page 134.

perform for its customers in lieu of Energy+ owning the distribution assets directly, and recovering the costs through its cost allocation.

OEB staff observed that contrary to Energy+'s statement that it does not charge any of its embedded distributors for LV service, it should be charging the customers of the BCP service area based on the rate design and tariff of the applicable General Service 50 to 4,999 kW rate class.[131] OEB staff also noted there is precedent for LV charges being applied on the tariffs of rate classes dedicated to embedded distributors.

OEB staff agreed with Energy+ that in the instance where a feeder passes through its service territory, it is both host and embedded on that feeder to the same distributor, and it has a reciprocal agreement with that distributor to not apply sub transmission charges in exchange for not applying LV charges in respect of the same load. In that case, OEB staff agreed that it is appropriate to not apply LV charges. In all other instances, OEB staff submitted that for the reasons outlined above, LV charges should apply to embedded distributors.[132]

Hydro One supported Energy+'s intent to charge LV to rate classes exclusive of embedded distributers as it views these costs to be upstream costs associated with serving end-use customers. It noted that none of its load that is embedded with Energy+ contributes to the ST charges that Hydro One levies to Energy+.[133]

VECC disagreed with Energy+'s Argument in Chief's assertion that LV charges are "allocated to each rate class based on the proportion of proposed retail transmission connection revenue from each class"[134] as embedded distributor classes are excluded from the allocation of LV costs. VECC's view was that the "pooling" approach be used, as is the case for RTSRs.[135]

Hydro One submitted that if the OEB were to accept VECC and OEB staff's position, then the current arrangement between Hydro One and Energy+ regarding Hydro One's ST charges would cease to apply for all Hydro One delivery points. Hydro One would levy ST charges on the full load withdrawn by Energy+ from Hydro One's system, including the Hydro One load embedded within Energy+ (except for Hydro One No.2 in the BCP service area).[136]

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[131] OEB Staff Submission, page 28.
[132] OEB Staff Submission, page 28.
[133] Hydro One Submission, page 2.
[134] Argument-in-Chief, page 23.
[135] VECC Submission, page 29.
[136] Hydro One Supplemental Submission, page 4.

VECC was not clear on why Hydro One does not charge ST in respect of its own load – whether itis because it is fed from lines owned by Hydro One and there is a reciprocal agreement, or if Hydro One, as an embedded distributor, is not fed off lines owned by Hydro One.[137]

Energy+ submitted that if the OEB directs it to allocate LV charges to all embedded distributors, it will need to work with Hydro One to adjust the current settlement methodology which will likely increase the total ST charges that Hydro One bills to Energy+, and that this would need to be reflected in final rates.[138]

Findings

Energy+ is both a host and an embedded distributor of Hydro One. The reciprocal arrangement wherein Energy+ does not charge Hydro One LV charges and Hydro One does not charge Energy+ sub-transmission charges is reasonable. The OEB agrees with OEB staff that Energy+ should assess LV charges to embedded distributors in all other instances.

Gross Load Billing for RTSRs

Energy+ is charged on a gross load billing basis by the Independent Electricity System Operator (IESO) for line and transformation connection service charges since it has a Large Use customer with LDG. Energy+ proposed to charge the RTSRs to this customer on a gross load basis to ensure that there are no cross-subsidies between customers. Energy+ also requested the gross load billing methodology for RTSRs for any customer in the future that implements Load Displacement Generation (LDG) to align to the methodology used by the IESO.[139]

CCC, SEC and VECC supported the proposal of using gross load billing for RTSRs.[140] OEB staff and TMMC submitted that Energy+ should continue to use the existing approach pending any further direction from the OEB.[141]

[137] VECC Supplemental Submission, page 7.
[138] Energy+ Reply Submission, page 52.
[139] Exhibit 8, page 17 of 157.
[140] CCC Submission, page 5. SEC Reply Submission, page 5. VECC Reply Submission, pp. 8-9.
[141] OEB Staff Submission, page 27. TMMC Submission, pp. 21-22.

Energy+ submitted that the OEB's plan to review the matter on a generic basis is not an adequate reason to refrain from approving Energy+'s proposal in this proceeding. It stated that the proposed gross load billing methodology for RTSRs is founded on the principles of cost causality and it is not appropriate for other customers to pay costs caused by a customer with LDG.[142]

Energy+ also acknowledged a recent OEB decision on Niagara-on-the-Lake Hydro Inc.'s 2019 Cost of Service application, in which the OEB approved the use of gross load billing for RTSRs.[143]

Findings

The Energy+ proposal to bill the Retail Transmission Rate – Line and Transformation Connection Service Charge to customers with LDG on a gross load billing basis is approved. In the Niagara on the Lake Hydro decision,[144] the OEB approved a similar proposal by the distributor to charge RTSRs on a gross load billing basis to a customer with embedded LDG in the same way that the IESO billed the distributor for those charges. The OEB found that the proposal aligned with the principles of cost causality and avoided a subsidy of the customer with embedded LDG that only provided benefits to that customer.

While the OEB may consider this issue on a generic basis in the future, both VECC and Energy+ have noted that the OEB's recent draft report on Commercial and Industrial Rate Design did not deal at all with the issue of gross load billing for RTSRs. As noted in the Niagara on the Lake decision, a cost of service application involves the setting of rates that must be determined on the basis of the reasonableness of the utility expenses, and then the correct allocation of those expenses in rates. In line with those objectives, the Energy+ proposal provides fair and reasonable allocation of RTSRs costs.

The OEB finds that the gross load billing method should be applied to a generator unit rating of 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. This is consistent with how the IESO bills Energy+ for Line Connection and Transformation Connection services.[145] The OEB expects Energy+ to

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[142] Energy+ Reply Submission, paragraph 206.
[143] Energy+ Reply Submission, paragraph 207.
[144] EB-2018-0056
[145] EB-2018-0326, 2019 Ontario Uniform Transmission Rate Schedules, issued December 20, 2018.

propose wording changes as necessary in its tariff of rates and charges to reflect OEB's decision as part of the draft rate order process.

3.5 Standby Charge

Energy+ and TMMC's Standby Charge Proposals

Energy+ proposed standby charges using a contracted capacity method where a customer contracts for a peak load requirement, initially based on the actual historical peak demand of the customer, but which could be reduced if the customer demonstrates an ability to shed load.[146] Energy+ proposed a standby rate that is the same as the volumetric rate of the customer's rate class. This has the effect that the distribution charge is the same regardless of the customer's consumption, as long as it is not more than the contracted capacity.[147] In the event that a customer's load exceeds the contracted capacity, the customer would be billed for actual demand. Energy+ did not propose a penalty for exceeding the contracted capacity, but would consider a need to revise the contracted capacity should the customer exceed the contracted amount.[148]

Energy+ proposed that the standby charge would apply to all GS 50-999 kW, GS 1000-4999 kW and Large Use customers that have load displacement generation and require Energy+ to act as a backup supply of electricity in the event the source of generation is unavailable.[149]

TMMC proposed a two-part standby charge consisting of, firstly, a contracted capacity charge based on TMMC's proposed standby contract demand of 6,900 kW[150] and secondly, a daily charge based on an allocation of the cost of shared facilities (poles) for those working days[151] when TMMC requires delivery of standby services due to an outage of its LDG.

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[146] Argument-in-Chief, page 25.
[147] Oral Hearing, Day 1, page 98.
[148] Oral Hearing, Day 1, page 102.
[149] Argument-in-Chief, page 25.
[150] Updated Pollock Evidence, *op. cit.*, page 28.
[151] TMMC uses the term peak days to reference weekdays excluding holidays between the hours of 7am and 7pm.

Using 2017 actual data, the total annual cost of the standby service proposed by Energy+ is $71,304.[152] As proposed by TMMC, the annual cost is under $2,000.[153]

OEB staff stated that other distributors such as Hydro Ottawa Limited (Hydro Ottawa) and Kingston Hydro Corporation (Kingston Hydro) offer a contracted capacity standby service. While Energy+ is proposing that its contracted capacity would be based on the total of power delivery and standby, the approach used by Hydro Ottawa and Kingston Hydro is to apply the distribution rate to metered demand and apply a standby charge based on the contracted capacity of standby power and a standby rate. Where the customer requires delivery of some or all of the contracted standby service, the metered consumption would reflect this, and the standby charge would be reduced accordingly to reflect any remaining capacity that was still standing by.[154]

OEB staff submitted that the standby charge proposed by Energy+ is appropriate and, while it is not the same as that used by Hydro Ottawa and Kingston Hydro, it has merits of simplicity in measurement and rate design and ascribes a tangible charge to standby services.[155]

OEB staff noted that the method proposed by TMMC requires a new means of tracking outages and a multi-part rate calculation outside of the models.[156]

OEB staff stated that, given that a generic policy and transition have not been determined by the OEB, it would be reasonable for Energy+ to apply the approved standby charge until its next rebasing. [157]

VECC criticized both Energy+'s and TMMC's proposals. VECC submitted that, according to Energy+'s proposal, the customer's monthly bill will be based on the contracted capacity and that standby charges could be applied to a quantity that exceeds the nameplate capacity of the customer's generation. Such a result, according to VECC, would be inconsistent with the objective of standby rates.[158] VECC noted that TMMC's proposal addresses this shortcoming, but makes an unclear distinction

[152] 30,443 kW x 2.3422 $/kW
[153] Updated Pollock Evidence, *op. cit.*, filed March 1, 2019, Schedule JP-16 Revised.
[154] OEB Staff Submission, page 30.
[155] OEB Staff Submission, pp. 30-31.
[156] OEB Staff Submission, page 31.
[157] OEB Staff submissions referred to the *Staff Report the Board: Rate Design for Commercial and Industrial Electricity Customers*, EB-2015-0043, February 21, 2019.
[158] VECC Submission, pp. 30-31.

between local vs shared facilities,[159]limits standby to a definition of peak days and hours which may not be consistent with Energy+'s actual peak, and assumes a linear relationship between standby load requirements and TMMC's monthly peak.[160]

VECC submitted that neither Energy+'s nor TMMC's approach should be accepted. Instead, the OEB should endeavor to complete the rate design consultation as soon as possible.[161]

SEC took issue with the process for negotiating contracted capacity as there is no neutral third-party who can make a determination if the customer does not agree with the utility and there is little guidance for how the contracted capacity should be determined.[162] SEC noted the asymmetry of bargaining power between an individual customer and Energy+, particularly smaller GS > 50 kW and GS > 1000 kW customers. SEC also shared VECC's concern that reductions in demand unrelated to standby would not be rewarded in lower bills.[163]

With respect to TMMC's approach, SEC argued that there are significant practical challenges for Energy+ to adopt the proposed two-part rate methodology for more plentiful, lower volume standby customers. SEC shared VECC's concerns with respect to the determination of local or shared assets dependency of a linear relationship between standby needs and monthly peak.[164]

Contrasted with the TMMC proposal for standby rates, Energy+ submitted that its proposal can be utilized for all customers with LDG in a variety of classes, while there would be significant practical challenges to adopt TMMC's proposal for small LDG facilities and there is no other LDC using a standby methodology that incorporates a multi-part calculation as proposed by TMMC.[165]SEC submitted neither Energy+'s nor TMMC's approach should be accepted and Energy+ should be required to implement the outcome of the OEB's Commercial and Industrial (C&I) consultation.[166] CCC supported VECC's and SEC's positions.[167]

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[159] Updated Pollock Evidence, page 16. TMMC defines that "Shared distribution facilities are generally used by all customers, whereas local distribution facilities serve only a specific customer or customer groups."
[160] VECC Submission, pp. 31-33.
[161] VECC Submission, page 33.
[162] SEC Submission, paragraph 32.
[163] SEC Submission, pp. 10-11.
[164] SEC Submission, pp. 11-13.
[165] Energy+ Reply Submission, pp. 60-61.
[166] SEC Submission, page 13.
[167] CCC Reply Submission, page 2.

Energy+ disagreed with VECC and SEC that the implementation of a standby charge should be deferred pending the outcome of the C&I consultation and that argued that approving Energy+'s proposal would not impair the OEB's ability to adopt a similar or an alternative methodology in a future decision.[168]

In response to VECC and SEC, OEB staff noted that the timeline for the development of the policy as well as the content of any policy resulting from the C&I consultation is unknown. OEB staff submitted that a standby charge is appropriate at this time and supported Energy+'s proposal.[169]

TMMC submitted that Energy+'s proposed standby charge could result in charges not based on any measure of the actual amount of delivered standby power drawn. TMMC noted that Energy+ provided no explanation for how it determined the standby contract demand for TMMC and that Energy+ ignored the reduction in the amount of capacity that had to be reserved for TMMC as a result of the LDG reducing TMMC's peak demand. TMMC also noted that Energy+'s proposal for standby rates would send the wrong price signals and discourage customers with LDG from scheduling outages in advance at times when the distribution system is less stressed.[170]

Energy+ noted that it requested permission to begin charging based on gross load billing in its 2015 IRM application,[171] and this request was denied as it was determined to be inappropriate in the context of an IRM application but could be brought as a separate application. Energy+ stated that this Cost of Service application is the appropriate time for the OEB to approve the proposed standby rate and gross load billing.[172]

Energy+ stated that its contracted capacity methodology is very similar to that used by TMMC and others for natural gas services from Enbridge Gas Inc. and disagreed with SEC and TMMC that there is little guidance on how contracted capacity should be determined. Energy+ stated that its proposal includes historical peak demand as the initial basis, and the customer can request a lower contracted amount if it can demonstrate an ability to shed load when its LDG is not operating. With respect to changes in load that have nothing to do with LDG, Energy+ acknowledged that there are factors that should be considered in determining whether the contracted capacity could be increased or decreased on an annual basis. These factors include a material

[168] Energy+ Reply Submission, page 54.
[169] OEB Staff Supplemental Submission, page 4.
[170] TMMC Submission, pp 22-23.
[171] EB-2014-0060.
[172] Energy+ Reply Submission, page 55.

change in the amount of peak load due to changes in business conditions, implementation of new technology and/or conservation initiatives that are persistent.[173]

Energy+ submitted that that recent changes by the government of Ontario to eliminate the role of LDCs in delivering conservation programs may affect an LDC's ability to recover LRAMVA claims and that, in the absence of a standby rate and LRAMVA, it would be directly harmed financially if future LDG projects come on-line.[174]

Adjustment to Demand Allocators to Reflect the Standby Charge Proposal

TMMC did not agree with the adjustment Energy+ made to the demand allocation factors (12CP, 4NCP and 12 NCP) for the Large Use class in the cost allocation model. TMMC stated that the proposed adjustment assumes that TMMC will require 26,222 kW each and every month during the forecast period, which results in a gross overstatement of TMMC's system usage.[175]

OEB staff noted that it is the OEB's policy that costs are allocated to rate classes on the basis of cost drivers, and that these include CP and NCP allocators. As a result, demand allocators are adjusted above the metered demand to reflect the additional capacity that is standing by and OEB staff submitted that Energy+'s adjustment is not unreasonable.[176]

Energy+ submitted that the OEB cost allocation policy supports adjustment to the demand allocators for the contract capacity standby service and the impact of the standby service should reflect the fact that the standby facilities need to be in place whether they are used or not. Non-adjustment of the demand allocators would not allocate the proper cost to the class that is requesting the standby service.[177]

Findings

The OEB will not approve Energy+'s proposal for a standby charge at this time. While it is appropriate that such a charge be adopted to capture the system costs associated with providing backup supply for LDG, the OEB agrees with positions advanced by VECC, SEC and CCC that there are problems associated with the methodologies of

[173] Energy+ Reply Submission, pp 55-58.
[174] Energy+ Reply Submission, page 59.
[175] TMMC Submission, page 11.
[176] OEB Staff Supplemental Submission, pp 4-5.
[177] Energy+ Reply Submission, pp. 31-32.

both Energy+ and TMMC that prevent OEB approval of a calculation of a charge that correctly captures the utility cost of providing the service. These include shortcomings in Energy+'s use of contracted capacity as the measurement tool by reason of variances in a customer's load requirement, and the necessity of successful negotiation of that figure with the customer. TMMC's proposal lacks clarity with respect to the definition of local versus shared distribution facilities and proposes a two-part standby rate that requires a new means of tracking outages and an administratively complex two-part billing process.

The OEB acknowledges that the non-implementation of a standby charge means that TMMC would not be allocated real costs of Energy+ in maintaining sufficient capacity to ensure reliability of service in the event of failure of TMMC's LDG. However, it is important that any charge be developed with a methodology that accomplishes that goal in an efficient and understandable fashion so that all customers are protected while customer innovation is also encouraged. The current OEB Commercial and Industrial (C&I) consultation,[178] followed by a subsequent OEB report should provide some guidance on the proper calculation of standby charges in circumstances of embedded generation that meet those objectives.

3.6 Group 2 Deferral and Variance Accounts

Group 2 Deferral and Variance Account Balances

Account 1575 and Account 1576

OEB staff had no concerns with the Group 2 Deferral and Variance Account (DVA) balances with the exception of the balances in Account 1575 IFRS-CGAAP Transition PP&E Amounts Balance + Return Component and Account 1576 Accounting Changes Under CGAAP Balance + Return Component. OEB staff submitted that the audited 2018 balances for each account should now be available and Energy+ should update the disposition amounts for both accounts to reflect the 2018 audited balances.[179]

[178] *Staff Report the Board: Rate Design for Commercial and Industrial Electricity Customers*, EB-2015-0043, February 21, 2019.
[179] OEB Staff Submission, page 42.

Energy+ responded that it is not proposing to update the balances in these accounts to reflect 2018 actuals and that doing so without a corresponding adjustment to rate base would create inconsistencies and reconciliation issues in future applications.[180]

Interest on Principal DVA Balances

Energy+ agreed with OEB staff's submissions on the interest on principle DVA balances and agreed to make the following updates as part of the draft rate order process[181]:

- Update 2018 projected interest calculation using the published Q3 and Q4 2018 OEB prescribed rates
- Forecast interest up to the implementation date of the rate riders from this proceeding and update the disposition amounts of the Group 2 DVA accounts accordingly

CCC, SEC and VECC made submissions on the proposed balances of two Account 1508 sub-accounts: Other Regulatory Assets – Monthly Billing and Other Regulatory Assets – OEB Assessment Costs.

Account 1508 Sub-Account: Monthly Billing

Energy+ is seeking recovery of $416,346 resulting from the cost of changing from bi-monthly billing to monthly billing for the CND Hydro service territory. Energy+ stated that the increased cash flow as a result of the transition would have generated additional interest income[182] and estimated that it was $91,237 for 2016 and 2017.[183]

SEC disagreed with Energy+'s approach of estimating the cash flow benefit and submitted that the appropriate way to measure it is to determine what the change in working capital would be compared to that built into the rates.[184]

Based on the OEB's analysis of determining the default working capital allowance of 7.5%, SEC attempted to estimate the cash flow benefit in the following steps[185]:

180 Energy+ Reply Submission, paragraph 324.
181 Energy+ Reply Submission, page 67.
182 Energy+ Argument-In-Chief, paragraph 112.
183 Energy+ Update to Evidence, December 13, 2018, page 20.
184 SEC Submission, paragraph 24.
185 SEC Submission, pp. 7-8.

- If all customers were on bi-monthly billing versus monthly billing, the difference is a 4.2% change in the total working capital allowance
- Adjusting 4.2% by 30% (4.2%x30%=1.26%) to reflect the fact that only residential and GS<50 kW customers were ever on bi-monthly billing
- Applying the 1.26% working capital allowance change to CND Hydro's 2014 working capital amount ($1,489,594) included in revenue requirement would result in an annual reduction of $143,001 ($1,489,594x (1.26%/13%)=$143,001)

Using the same methodology for 2017, SEC submitted that the appropriate recoverable amount is $96,518 for 2016 and $222,717 for 2017 plus the applicable carrying charges.[186]

CCC and VECC supported SEC's argument.[187]

Energy+ argued that the SEC's approach constitutes retroactive ratemaking as it relates to the working capital allowance previously approved for the former CND Hydro and BCP's rate base.[188] The OEB had approved the establishment of this account to record any incremental OM&A costs directly attributable to the transition to monthly billing in CND Hydro's 2016 rate application and, while the OEB identified cost reductions in that decision, it did not prescribe how the improvements in cash flow should be measured.[189] Energy+ submitted that it is reasonable to conclude that each of the calculations should be done on a similar basis, whether an actual cost basis or on a retroactive basis.[190]

<u>Account 1508 Sub-Account: OEB Assessment Costs</u>

Energy+ proposed to dispose a balance of $174,262 for this account.

SEC submitted that the OEB should deny clearance of the balances in this account for 2016 and 2017 since the principal balances ($70,507 in 2016 and $99,102 for 2017) are both below the Energy+'s materiality threshold of $250,000.[191] VECC submitted that this

[186] SEC Submission, paragraph 28.
[187] CCC Reply Submission, page 1.
[188] Energy+ Reply Submission, paragraph 306.
[189] EB-2015-0057
[190] Energy+ Reply Submission, paragraph 302.
[191] SEC Submission, paragraph 20.

account should be closed without disposition.[192] CCC supported SEC and VECC's submissions.[193]

Energy+ noted that an additional $80,302 was estimated to be recorded in this account in 2018, resulting in a cumulative total balance of $254,564 as December 31, 2018, which exceeds the materiality threshold of $250,000 used by SEC.[194] Energy+ noted that the actual materiality threshold for 2019 is $171,639.[195]

In response to VECC's comment that Energy+ should distinguish the nature of the variances between the variance caused by methodology change and the variance resulting in between the forecast OEB assessment cost and actual cost, Energy+ noted that it has followed the OEB's direction in recording variances in this account.[196]

Energy+ identified two proceedings, Lakeland Power Distribution Ltd. and Centre Wellington Hydro Ltd., in which the OEB Cost Assessment accounts were approved for disposition as part of the settlement agreement.[197]

Findings

Account 1575 and Account 1576:

The OEB finds that there is no need to update the balances in these accounts to reflect the 2018 actuals because of potential reconciliation issues in future applications.

Interest on Principal DVA Balances

The OEB directs Energy+ to make the following updates as part of the draft rate order process.

- Update 2018 projected interest calculation using the published Q3 and Q4 2018 OEB prescribed rates

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[192] VECC Submission, paragraph 4.4.
[193] CCC Reply Submission, pp.1-2.
[194] Energy+ Reply Submission, pp. 72-73.
[195] Calculated in accordance with the Chapter 2 Filing Requirements. Energy+ Reply Submission, paragraph 313.
[196] Energy+ Reply Submission, paragraph 316-317.
[197] Energy+ Reply Submission, paragraph 319.

- Forecast interest up to the implementation date of the rate riders from this proceeding and update the disposition amounts of the Group 2 DVA accounts accordingly

Account 1508 Sub-Account: Monthly Billing

The OEB agrees with SEC's proposed approach and directs Energy+ to implement it. The OEB does not agree that this approach constitutes retroactive ratemaking as it is based on an established OEB approach and analysis.

Account 1508 Sub-Account: OEB Assessment Costs

The OEB approves clearances of the balances in this account based on the materiality of the balance to be disposed.

Discontinued and New DVA Account

New DVA Account

Although the Parties agreed that the gain from the sale of the Dundas Street property will be disposed of at a later date, OEB staff submitted that a new DVA account to track this gain would still be required and would need to be approved in the current application. OEB staff supported the proposed draft accounting order for the new DVA account 1508 Other Regulatory Asset – Sub-Account – Gain on Sale.[198]

Discontinued DVA Accounts

Energy+ proposed to discontinue the following Group 2 DVA Account Balances:[199]

1508 Other Regulatory Asset – Sub-Account – Deferred IFRS Transition Costs

1557 Meter Cost Deferral Account (MIST Meters)

1572 Extra-Ordinary Event Costs

1575 IFRS-CGAAP Transition PP&E Amounts Balance

1576 Accounting Changes under CGAAP

[198] OEB Staff Submission, pp. 43-44.
[199] Exhibit 9.3.5, Table 9-20 summarizes the accounts that Energy+ is seeking to discontinue.

OEB staff supported Energy+’s proposal to discontinue these DVA accounts with the exception of Accounts 1575, 1576 and 1557. OEB staff submitted that Accounts 1575 and 1576 should remain open to track the actual 2018 transactions, and any material residual balance in the accounts, compared to what was approved as part of the current application, should be brought for disposition at the next cost based rate application.[200] Energy+ agreed with OEB staff’s submission.[201]

Regarding Account 1557 (MIST Meters), OEB staff noted that it is not clear why Energy+ would be seeking to discontinue this account when it appears that the related work is yet to be completed and that further costs are to be incurred in 2018 and 2019.[202]

Energy+ explained that the MIST meter capital projects for 2018 and 2019 have been included in rate base as part of this application and it does not expect to record any further costs in this account after December 31, 2017.[203]

Findings

New DVA Account

The OEB agrees with OEB staff that the new DVA account needs to be established as part of this proceeding and directs Energy+ to do so.

Discontinued DVA Accounts

The OEB agrees to discontinue proposed DVA balances except 1575 and 1576 for the reasons cited by OEB staff. The OEB also agrees to discontinue the balance in 1557 based on Energy+’s reason that no further costs are to be recorded in this account beyond 2017.

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[200] OEB Staff Submission, page 44.
[201] Energy+ Reply Submission, paragraph 322.
[202] OEB Staff Submission, page 44.
[203] Energy+ Reply Submission, paragraph 326.

Bill C-97

The OEB has become aware of certain upcoming tax changes that may have an impact on the revenue requirement that will be approved in this proceeding.

In particular, as part of the November 21, 2018 Federal Fall Economic Statement, the Finance Minister of Canada tabled plans for a tax incentive program, referred to as the *Accelerated Investment Incentive (AII)*, which provides for accelerated tax deductions (CCA) on most new capital investments. The March 19, 2019 Federal Budget further confirmed the federal government's intention to proceed with the accelerated CCA program.

Under the proposed AII measure, certain capital property that is subject to the general CCA rules will be eligible for an enhanced first-year CCA deduction. The property will be eligible if it is acquired after November 20, 2018, and becomes available for use before 2028. The incentive's general rule will be made up of two elements:

- applying an enhanced CCA rate to the net additions of an asset class equal to one-and-a-half times the current prescribed CCA rate
- suspending the existing CCA half-year rule

As a result, eligible property currently subject to the half-year rule will, in essence, qualify for an enhanced CCA equal to three times the normal first-year deduction. However, the AII does not change the total amount that a utility can deduct over the life of a property, it simply alters the timing of these deductions. By claiming a larger CCA deduction in the first year, there will be smaller CCA deductions in future years.

As of the date of this Decision and Order, the proposed tax changes (as part of Bill C-97) have not received Royal Assent and therefore do not form part of enacted legislation.

Energy+ has not incorporated these proposed tax changes within their PILs calculations for this proceeding.

The Accounting Procedures Handbook (APH) requires distributors to record the impact of any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the OEB Tax Model in Account 1592 - PILs and Tax Variances. In the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (3rd Generation Report), the OEB determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the OEB-approved base rates for a distributor, was appropriate.

Findings

For the purpose of distinguishing variances resulting from the proposed Bill C-97 changes from other potential legislative or regulatory changes to the tax rates or rules, the OEB directs Energy+ to establish a new sub-account within Account 1592 - PILs and Tax Variances specifically for the purposes of recording the impact of changes in CCA rules. This account will be effective November 21, 2018 (the proposals in Bill C-97 allow for accelerated first year tax depreciation on eligible capital expenditures made after November 20, 2018).

The OEB directs Energy+ to record the full revenue requirement impact of any differences between the CCA rules and assumptions used in setting base rates in a given year, and the rules in effect for that year. The determination of the disposition methodology and allocation of any accumulated balances in this new 1592 sub-account will be made by the OEB when these balances are brought forth for disposition at a future date. The OEB's future determinations regarding the disposition of this new sub-account will not be bound by the 50/50 sharing criterion identified in the 3rd Generation Report.

Lost Revenue Adjustment Mechanism Variance Account

To address the impact of reduced consumption due to conservation and demand management (CDM) programs, the OEB established a Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) which captures the differences in distributor revenue between actual load and the last OEB-approved load forecast.[204]

Energy+ is seeking to dispose of an LRAMVA debit balance of $1,545,772 as of December 31, 2017. The balance represents the lost revenue amount in the CND Hydro service territory of $1,177,449 and lost revenue in the BCP service territory of $368,323.

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[204] Guidelines for Electricity Distributor Conservation and Demand Management, EB-2012-0003, April 26, 2012; and Requirement Guidelines for Electricity Distributors Conservation and Demand Management, EB-2014-0278, December 19, 2014.

In the CND Hydro service territory, the LRAMVA debit balance consists of lost revenues from 2014 to 2017 CDM programs delivered during the 2011 to 2017 period, and associated carrying charges. Actual savings were compared against forecast savings of 39,520,173 kWh, set out in the former CND Hydro's 2014 cost of service proceeding.[205]

In the BCP service territory, the LRAMVA debit balance consists of lost revenues from 2016 to 2017 CDM programs delivered during the 2011 to 2017 period, and associated carrying charges. Actual savings were compared against forecast savings of 1,494,000 kWh, set out in the former BCP's 2011 cost of service proceeding.[206]

Energy+'s LRAMVA balance includes demand savings from a CHP project undertaken as part of TMMC's participation in the IESO's Process and Systems Upgrade program. The OEB's updated LRAMVA policy indicates that distributors should multiply the peak demand (kW) savings amounts from energy efficiency programs included in the IESO Final Results by the number of months the IESO has indicated those savings take place throughout the year (generally 12 months for all programs).[207]

Energy+ proposed an alternative methodology to calculate the demand savings for TMMC's CHP project. Rather than calculating annual savings by multiplying 12 months by the average demand savings from the IESO's evaluations, Energy+ proposed to calculate annual savings by taking the difference between the monthly peak on the distribution system (with the CHP project running) and the monthly peak of the entire TMMC facility inclusive of generation (in the absence of the CHP project) and summing these differences throughout the year.

OEB staff, VECC and CCC supported Energy+'s proposed methodology to calculate demand savings for the CHP project.

OEB staff submitted that the OEB's updated LRAMVA policy allows a distributor to provide supporting documentation in the event it makes a utility-specific proposal, and the calculation proposed by Energy+ aligned with the manner in which the facility and customer were billed.[208]

[205] Decision and Order, EB-2013-0116, August 14, 2014
[206] Decision and Order, EB-2010-0125, May 9, 2011
[207] Report of the Ontario Energy Board – "Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs." EB-2016-0182, May 19, 2016.
[208] OEB Staff Submission, pp. 36-37.

VECC submitted that the OEB should accept Energy+'s computation of lost revenues and agreed that the alternative methodology represents a verifiable proxy for lost revenues attributable to the generation project. CCC agreed with VECC's submission.

OEB staff, VECC, SEC and CCC agreed with Energy+'s proposed disposition of the LRAMVA balance for the CHP project to the Large Use class, consistent with the OEB's policy of recovering lost revenues from those customers who participated in the IESO's CDM program. TMMC stated that the recovery of lost revenues from its LDG facility solely from the Large Use class was unfair[209], although it did not make any submissions on this matter in its reply submission.

Energy+ included $108,446 in the LRAMVA from street light savings in the BCP service territory arising from Brant County's participation in the saveOnEnergy Retrofit program which involved conversion to higher efficiency street light bulbs. Energy+ proposed to calculate the savings by using the difference between total billed demand before and after the retrofit program. OEB staff, VECC and CCC took no issue with Energy+'s calculation of demand savings from the street light upgrades in the BCP service territory.

No party expressed concern with the disposition of Energy+'s revised LRAMVA debit balance of $1,545,772 over a one-year period.

Findings

The OEB finds that the proposed disposition of Energy+'s revised LRAMVA debit balance, shown in Table 1 below, is appropriate and consistent with OEB's policy.

[209] Oral Hearing Transcript, Vol. 2, page 110.

Table 1. LRAMVA Balance for Disposition

Account Name	Account Number	Actual CDM Savings ($) A	Forecasted CDM Savings ($) B	Carrying Charges ($) C	Total Claim ($) D=(A-B)+C
LRAMVA – CND Hydro service territory	1568	$ 3,051,336	$ 1,906,981	$ 33,093	$ 1,177,449
LRAMVA – BCP service territory	1568	$ 395,267	$ 37,169	$ 10,226	$ 368,323
LRAMVA – Total	**1568**	**$ 3,446,603**	**$ 1,944,150**	**$ 43,319**	**$ 1,545,772**

Group 2 Deferral and Variance Accounts Disposition

OEB staff submitted that Energy+ should dispose of its Group 2 DVA balances by service territory, on the basis of cost causality, and not on a harmonized basis as proposed by Energy+.[210]

No other party objected to Energy+'s proposal to dispose Group 2 DVA balances on a harmonized basis.

Energy+ identified the following reasons in support of disposing Group 2 DVA balances on a harmonized basis[211]:

- Energy+ promised to harmonize rates for customers in the CND Hydro and BCP service territories in 2019
- Between 67% and 86% of low-volume customers agreed with the concept of rate harmonization
- Harmonized rate riders will reduce administrative time spent on the DVA reconciliation process

[210] OEB Staff Submission, page 42.
[211] Energy+ Reply Submission, pp. 63-65.

- A decision that requires the disposition of Group 2 DVA on a service territory basis, but approves rate harmonization and disposition of Group 1 accounts, would be confusing to customers
- Not all Group 2 accounts, including the LRAMVA claim, were actually accumulated individually by service territory
- When taking into consideration the overall rate harmonization plan, the disposition of Account 1575 and 1576 on a harmonized basis would better reflects the principle of cost causality

Energy+ prepared a table that compared the total bill impact for all customer classes in the two service territories under the scenarios of disposing Group 2 DVA balances on a harmonized basis versus by service territory.[212] BCP customers who would benefit from lower distribution rates due to rate harmonization would further benefit from disposition of the credit balance in Account 1576, while CND Hydro customers who would be impacted by higher rates resulting from rate harmonization would be further penalized by the recovery of the debit balance in Account 1575.[213]

Energy+ submitted that if the OEB decides that Energy+ must dispose of Group 2 DVA balances by rate zone, it should be limited solely to the 2019 test year because tracking and disposing balances separately on a going forward basis would undermine the purpose of rate harmonization and create incremental administrative work that would reduce the net efficiencies gained from the acquisition.[214]

Findings

The OEB accepts Energy+'s proposal to dispose of Group 2 DVA balances on a harmonized basis for the reasons cited by Energy+.

[212] Energy+ Reply Submission, paragraph 278.
[213] Energy+ Reply Submission, paragraph 279.
[214] Energy+ Reply Submission, paragraph 280.

3.7 Load Forecast

The OEB's determination on the unsettled issues could affect the settled load forecast and the resulting billing determinants.

OEB staff submitted that Energy+ should remove the load adjustments to the Large Use class if the OEB determines not to implement a standby charge for LDG in this proceeding.[215]

Energy+ noted that TMMC has proposed a different methodology for the standby charge that includes a different contracted capacity level.[216]

No party objected to the adjustments should the OEB approve Energy+'s proposed standby charge nor the removal of the adjustments should the OEB determine not to implement a standby charge.

Findings

Given the OEB's decision in this proceeding not to approve the proposed standby charge at this time, Energy+ is directed to remove the load adjustments to the Large Use class.

[215] OEB Staff Submission, page 45.
[216] Energy+ Reply Submission, page 76.

4 IMPLEMENTATION

Energy+ shall include the cost consequences of the approved settlement proposal, updated to incorporate the findings in this Decision and Order on the unsettled issues, in its calculation of its revenue requirement for recovery from customers.

The OEB expects Energy+ to file detailed supporting material showing the impact of this Decision and Order on the overall revenue requirement, the allocation of revenues between classes and the derivation of base rates. The OEB expects that the implementation date will be August 1, 2019.

CCC, SEC and VECC are eligible for cost awards in this proceeding. The OEB has made provision in this Decision and Order for these intervenors to file their cost claims. The OEB will issue its cost awards decision after the following steps are completed.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Energy+ shall file with the OEB and forward to intervenors a draft rate order with a proposed Tariff of Rates and Charges (including a forgone revenue rate rider) attached that reflects the OEB's findings in this Decision and Order, no later than June 27, 2019. Energy+ shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order.
2. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB, and forward to Energy+, no later than July 9, 2019.
3. Energy+ shall file with the OEB and forward to intervenors, responses to any comments on its draft Rate Order no later than July 18, 2019.
4. Intervenors shall submit their cost claims no later than July 12, 2019.
5. Energy+ shall file with the OEB and forward to intervenors any objections to the claimed costs July 17, 2019.
6. Intervenors shall file with the OEB and forward to Energy+ any responses to any objections for cost claims no later than July 24, 2019.
7. Energy+ shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

DATED at Toronto June 13, 2019

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

SCHEDULE A

DECISION AND ORDER

ENERGY+ INC.

EB-2018-0028

DATED: JUNE 13, 2019

Settlement Proposal
Filed on December 12, 2018

EB-2018-0028

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

AND IN THE MATTER OF an application by Energy+ Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2019.

Energy+ Inc.
SETTLEMENT PROPOSAL

DECEMBER 12, 2018

Energy+ Inc.

EB-2018-0028

Settlement Proposal

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APPENDICES

Appendix A – Updated Revenue Requirement Work Form
Appendix B – Updated Appendix 2-AB: Capital Expenditure Summary
Appendix C – Updated Appendix 2-BA: 2018 & 2019 Fixed Asset Continuity Schedules
Appendix D – Updated 2018 and 2019 Capital Plan
Appendix E – Energy+ Responses to Clarification Questions
Appendix F – Approved Issues List

LIVE EXCEL MODELS

In addition to the Appendices listed above, the following live excel models have been filed together with and form an integral part of this Settlement Proposal:

- 2019 EnergyPlus Chapter2_Appendices – Settlement.xlsm
- 2019 EnergyPlus Benchmarking-Spreadsheet-Forecast-Model – Settlement.xlsx
- 2019 EnergyPlus Chapter 5 Appendix – Settlement.xlsx
- 2019 EnergyPlus Rev_Reqt_Work_Form – Settlement.xlsm
- 2019 EnergyPlus Test_year_Income_Tax_PILs_Workform_V1 – Settlement.xlsm
- 2019 EnergyPlus ACM_Model_OEB – Settlement.xlsm
- 2019 EnergyPlus Cost_Allocation_Model – Settlement.xlsm
- 2019 EnergyPlus DVA Continuity_Schedule_CoS – Consolidated – Settlement.xlsb
- 2019 EnergyPlus GA-Analysis-Workform - Consolidated - Settlement.xlsb
- 2019 EnergyPlus Tariff_Schedule_Model-CND – Settlement.xlsx
- 2019 EnergyPlus Tariff_Schedule_Model-BCP – Settlement.xlsx
- 2019 EnergyPlus Load Forecast Model – Settlement.xlsx
- 2019 EnergyPlus Load profile model 2006 Hydro One data for 2019 – Settlement.xlsm

Energy+ Inc.

EB-2018-0028

Settlement Proposal

Filed with OEB: December 12, 2018

1. Introduction

Energy+ Inc. (the "**Applicant**" or "**Energy+**") filed a complete cost of service application with the Ontario Energy Board ("**OEB**" or the "**Board**") on April 30, 2018 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the "**Act**"), seeking approval for changes to the rates that Energy+ charges for electricity distribution and other charges, to be effective January 1, 2019 (Board Docket Number EB-2018-0028) (the "**Application**").

The Board issued and Energy+ published a Notice of Hearing dated May 28, 2018 and Procedural Order No. 1 on July 26, 2018. Procedural Order No. 1 made provisions related to interrogatories and intervenor evidence, required the parties to the proceeding to develop a draft issues list and scheduled a settlement conference for November 7-9, 2018.

Energy+ filed its interrogatory responses with the Board on September 14, 2018, pursuant to which Energy+ updated several models and submitted them to the Board as Excel documents. Energy+ filed responses to additional clarification questions on September 19, 2018 and September 20, 2018 and additional submissions on September 21, 2018.

Toyota Motor Manufacturing Canada Inc. ("**TMMC**"), an intervenor in this proceeding, filed the Written Evidence of Melody Collis and of Jeffry Pollock on September 27, 2018 (together, the "**TMMC Evidence**", as revised). TMMC filed responses to interrogatories in respect of that evidence on October 25 and October 29, 2018, and revisions to Mr. Pollock's evidence on November 1, 2018.

On October 26, 2018, OEB staff submitted a proposed issues list to the Board as agreed to by the parties. The Board approved the issue list in Procedural Order No. 4 (Schedule A) dated October 31, 2018, and is attached as Appendix F to this Settlement Proposal.

2. Settlement Conference

Further to the Board's Procedural Order No. 1, a settlement conference, facilitated by Mr. Chris Haussman, was held from November 7, 2018 to November 9, 2018 and continued, via telephone and electronic correspondence, until December 12, 2018 (together, the "**Settlement Conference**"). The Settlement Conference was conducted in accordance with the Board's *Rules of Practice and Procedure* (the "**Rules**") and the Board's *Practice Direction on Settlement Conferences* (the "**Practice Direction**").

Energy+ and the following intervenors (the "**Intervenors**") (Energy+ and the Intervenors are collectively, the "**Parties**") participated in the settlement conference:

Consumers Council of Canada (CCC");
Hydro One Networks Inc. ("HONI")
School Energy Coalition ("SEC");
Toyota Motor Manufacturing Canada Inc. ("TMMC"); and
Vulnerable Energy Consumers Coalition ("VECC").

Brantford Power Inc. ("**BPI**"), an intervenor in this proceeding, did not participate in the Settlement Conference.

OEB staff also participated in the Settlement Conference in accordance with its role and responsibilities as described in the Practice Direction (p. 5). Although OEB staff is not a party to this Settlement Proposal, the Practice Direction binds the OEB staff who participated in the Settlement Conference to the same confidentiality requirements that apply to the Parties. Moreover, the Practice Direction prohibits OEB staff from discussing the content of this Settlement Proposal or the process by which it was reached with the Board panel assigned to this proceeding.

The Settlement Conference is subject to the confidentiality and privilege rules set out in the Practice Direction. The Parties acknowledge that the Settlement Conference is confidential in accordance with the terms of the Practice Direction. The Parties also understand and agree that confidentiality in this context does not have the same meaning as confidentiality in the context of the Board's Practice Direction on Confidential Filings and that the rules of that document do not apply to the Settlement Conference. In the context of the Settlement Conference and this Settlement Proposal, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the Settlement Conference, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference, are all strictly confidential, privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, namely, in the event production is required to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the Settlement Conference. However, in this context, the Parties agree that "attendees" includes persons who were not physically in attendance at the Settlement Conference but were a) any persons or entities that the Parties engaged to assist them with the settlement conference, and b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

3. Settlement Proposal

This Settlement Proposal is filed with the Board in connection with the Application and is organized in accordance with the Final Issues List.

This document is called a "Settlement Proposal" because it is a proposal by the Parties to the Board to settle the issues in this proceeding. It is termed a proposal as between the Parties and the Board. However, as between the Parties, and subject only to the Board's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth below, this agreement is subject to the condition subsequent that if it is not accepted by the Board in its entirety then, unless amended and refiled by the Parties and approved by the Board, it is null and void and of no further effect. In entering into this Settlement Proposal, the Parties understand and agree that, pursuant to the Act, the Board has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

This Settlement Proposal provides a brief description of each of the unsettled, partially settled, and settled issues together with references to the evidence that supports the settlement of each settled issue. The Parties agree that references to "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include (a) additional information included by the Parties in this Settlement Proposal; (b) the Appendices attached to the Settlement Proposal; and (c) the Live Excel Models included together with the Settlement Proposal. The Parties also agree that references to the evidence in this Settlement Proposal shall, unless the context otherwise requires, include the Application, the TMMC Evidence, the responses of Parties to interrogatories, clarification questions and undertakings and all other components of the record of proceeding EB-2018-0028, up to and including the date hereof.

The Parties who support each settled issue agree that the evidence in respect of each such settled issue is sufficient, in the context of the overall settlement, to support the proposed settlement of each such issue and that the totality of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the Board of this Settlement Proposal. The Parties agree that references to the evidence in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the responses to interrogatories, responses to clarification questions and undertakings, and all other components of the record up to and including the date hereof, including additional information included by the Parties in this Settlement Proposal and the Attachments to this document.

The Appendices to this Settlement Proposal provide further support for the settlement of the settled and partially settled issues. The Parties acknowledge that the Appendices were prepared by Energy+ to reflect this Settlement Proposal. While the Intervenors and OEB Staff have reviewed the Appendices and the Live Excel Models, the Intervenors are relying on the accuracy of the underlying evidence in entering into this Settlement Proposal.

Certain information in this Settlement Proposal (such as Table 3 (Summary of Bill Impacts), Table 5 (Load Forecast), Table 7 (Revenue to Cost Ratios) below) which assumes the Board accepts the Applicant's proposals on the unsettled issues, that it is included for information purposes only, in order to illustrate the impact of the Settlement Proposal on the balance of the Application, and is without prejudice to the Parties' right to take any position they choose on the unsettled issues.

The Parties have reached "Complete Settlements" or "Partial Settlements" with respect to some but not all of the issues included in the Final Issues List. Unless specified in this Settlement

Proposal, HONI and TMMC take no position on any of the settled or partially settled issues. Specifically:

"Complete Settlement" means an issue in respect of which Energy+ and the Intervenors who take a position on that issue, have agreed to a settlement of all aspects of the issue and if this Settlement Proposal is accepted by the Board, none of the Parties (including Parties who take no position on that issue) will adduce any evidence or argument during the oral hearing in respect of the specific issue.	# issues settled: **5**
"Partial Settlement" means an issue in respect of which Energy+ and the Intervenors who take a position on that issue have agreed on some, but not all, aspects of that issue. If this Settlement Proposal is accepted by the Board, the Parties (including Parties who take no position on the Partial Settlement) will only adduce evidence and argument during the hearing on the portions of the issue for which no agreement has been reached.	# issues partially settled: **3**
"No Settlement" means an issue in respect of which no settlement was reached. Energy+ and the Intervenors who take a position on the issue will adduce evidence and/or argument at the hearing on the issue.	# issues not settled: **6**

According to the Practice Direction (p. 3), the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. These adjustments are specifically set out in the text of the Settlement Proposal.

The Parties have settled the issues as a package, and none of the parts of this Settlement Proposal are severable. If the Board does not accept this Settlement Proposal in its entirety, then there is no settlement (unless the Parties agree in writing that any part(s) of this Settlement Proposal that the

Board does accept may continue as a valid settlement without inclusion of any part(s) that the Board does not accept).

In the event that the Board directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties who took on a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue prior to its resubmission to the Board.

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not Energy+ is a party to such proceeding.

Where in this Settlement Proposal, the Parties "Accept" the evidence of Energy+, or the Parties or Energy+ "agree" to a revised term or condition, including a revised budget or forecast, then unless the Settlement Proposal expressly states to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement. For greater certainty, and without limiting the generality of the foregoing, where in this document those words appear, they should not be interpreted as having any meaning other than the meaning imposed by the deemed inclusion of those words elsewhere in the document.

SUMMARY

Summary of Settlement

In reaching this settlement, the Parties have been guided by Filing Requirements for Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications dated July 12, 2018, the Issues List, the Report of the Board titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 ("**RRFE**"), and the Handbook for Utility Rate Applications (the "**Handbook**").

Energy+, CCC, VECC and SEC have reached a complete or partial settlement on the aspects of the Issues List that relate directly to revenue requirement, customer count, and with a limited exception, the load forecast,[1] as more fully detailed herein (the "**Revenue Requirement Settlement**"). A summary of the impact of the Revenue Requirement Settlement on each of the issues from the Board approved Issues List is presented below as Table 1.

Table 1 – Issues List Summary

Issue		Status	Supporting Parties	Parties taking no position
1.1	Capital	Partial Settlement	Energy+, CCC, VEC, SEC	TMMC, HONI
1.2	OM&A	Complete Settlement	Energy+, CCC, VEC, SEC	TMMC, HONI
2.1	Revenue Requirement Components	Complete Settlement	Energy+, CCC, VEC, SEC	TMMC, HONI
2.2	Revenue Requirement Determination	Complete Settlement	Energy+, CCC, VEC, SEC	TMMC, HONI
3.1	Load Forecast	Partial Settlement	Energy+, CCC, VEC, SEC	TMMC, HONI
3.2	Cost Allocation	No Settlement		
3.3	Rate Design, including distribution rate harmonization	No Settlement		
3.4	Residential Rate Design	No Settlement		
3.5	Retail Transmission Service Rates and LV Rates	No Settlement		
3.6	Gross Load Billing for Retail Transmission Rates for customers who have load displacement generation	No Settlement		
3.7	Standby Charge for Large Use customer classes with load displacement (Large Use, GS 1,000-4,999 kW and GS 50-999 kW)	No Settlement		
4.1	Impacts of Accounting Changes	Complete Settlement	Energy+, CCC, VEC, SEC	TMMC, HONI
4.2	Deferral and Variance Accounts	Partial Settlement	Energy+, CCC, VEC, SEC	TMMC, HONI
5.1	Effective Date	Complete Settlement	Energy+, CCC, VEC, SEC	TMMC, HONI

[1] TMMC taking "No Position" on the Partial Settlement of Issue 3.1 (Load Forecast) is subject to the understanding that the load forecast agreed upon by the supporting Parties may change as a direct result of the Board's disposition of certain issues that remain unsettled.

The Revenue Requirement Settlement includes consideration of the Energy+ responses to certain clarification questions made during the settlement conference, which responses are attached as Appendix E to this Settlement Proposal.

Table 2 summarizes the changes to Rate Base and Capital, Operating Expenses and Revenue Requirement from Energy+'s Application, as filed, interrogatories and clarifying questions and the proposed Revenue Requirement Settlement. Table 3 is a summary of bill impacts arising from this settlement and Table 4 is a summary of Capital Expenditures and OM&A. The Parties agree that Table 3 may change again to reflect the impact of the ultimate disposition of unsettled issues that have yet to be determined by the OEB.

Table 2 - Revenue Requirement Summary

Description		Application	Interrogatories	Variance	Settlement	Variance
		(A)	(B)	(C)=(B)-(A)	(D)	(E)=(D)-(B)
Cost of Capital	Regulated Return on Capital	$ 10,507,388	$ 10,641,468	$ 134,080	$ 10,690,995	$ 49,527
	Regulated Rate of Return	6.14%	6.14%	0.00%	6.15%	0.01%
Rate Base & Capital Expenditures	Rate Base	$ 171,191,397	$ 173,375,892	$ 2,184,495	$ 173,825,304	$ 449,411
	Net Fixed Assets	$ 157,990,651	$ 156,667,934	$ (1,322,717)	$ 157,130,096	$ 462,161
	Working Capital Base	$ 176,009,945	$ 222,772,772	$ 46,762,826	$ 222,602,772	$ (170,000)
	Working Capital Allowance	$ 13,200,746	$ 16,707,958	$ 3,507,212	$ 16,695,208	$ (12,750)
Operating Expenses	Amortization	$ 6,703,335	$ 6,423,985	$ (279,350)	$ 6,432,205	$ 8,220
	Taxes/PILs (Grossed Up)	$ 796,233	$ 753,897	$ (42,336)	$ 773,309	$ 19,412
	OM&A (incl. Property Taxes and LEAP)	$ 18,818,358	$ 18,623,358	$ (195,000)	$ 18,453,358	$ (170,000)
Revenue Requirement	Service Revenue Requirement	$ 36,825,314	$ 36,442,709	$ (382,606)	$ 36,349,867	$ (92,841)
	Other Revenue	$ 1,654,991	$ 1,870,459	$ 215,468	$ 2,022,079	$ 151,620
	Base Revenue Requirement	$ 35,170,323	$ 34,572,250	$ (598,074)	$ 34,327,788	$ (244,461)
	Grossed Up Revenue Deficiency	$ 1,543,390	$ 1,114,029	$ (429,361)	$ 869,568	$ (244,461)

Table 3 – Summary of Bill Impacts

CND Service Territory	kWh	kW	Distribution (Fixed & Volumetric)				Total Bill (Excluding HST)			
			Current 2018	Proposed 2019	$ Change	% Impact	Current 2018	Proposed 2019	$ Change	% Impact
Residential	750	-	$ 24.83	$ 27.61	$ 2.78	11.2%	$ 96.02	$ 102.30	$ 6.28	6.5%
Residential	313	-	$ 22.80	$ 27.61	$ 4.81	21.1%	$ 52.99	$ 59.66	$ 6.67	12.6%
GS < 50 kW	2,000	-	$ 43.21	$ 46.69	$ 3.48	8.1%	$ 243.70	$ 255.37	$ 11.67	4.8%
GS >50 to 999 kW	20,000	60	$ 368.05	$ 318.00	$ (50.04)	-13.6%	$ 3,415.31	$ 3,420.69	$ 5.38	0.2%
GS >1,000 to 4,999	800,000	2,000	$ 8,341.83	$ 8,453.67	$ 111.84	1.3%	$124,738.16	$ 126,050.38	$ 1,312.22	1.1%
Large Use	6,600,000	16,000	$48,858.20	$46,679.76	$ (2,178.44)	-4.5%	$959,490.65	$ 1,006,043.72	$ 46,553.08	4.9%
Unmetered Scattered Load	100		$ 7.15	$ 7.24	$ 0.09	1.2%	$ 17.39	$ 17.77	$ 0.39	2.2%
Street Lighting	400,000	700	$44,773.08	$35,339.88	$ (9,433.20)	-21.1%	$101,505.50	$ 98,037.38	$ (3,468.12)	-3.4%
EMB - WNH	-	8,280	$15,870.25	$11,283.98	$ (4,586.26)	-28.9%	$ 47,845.40	$ 37,972.43	$ (9,872.97)	-20.6%
EMB - HONI	1,382,000	2,574	$ 5,296.14	$ 4,515.57	$ (780.57)	-14.7%	$207,486.91	$ 201,417.93	$ (6,068.98)	-2.9%

Brant Service Territory	kWh	kW	Distribution (Fixed & Volumetric)				Total Bill (Excluding HST)			
			Current 2018	Proposed 2019	$ Change	% Impact	Current 2018	Proposed 2019	$ Change	% Impact
Residential	750	-	$ 28.28	$ 27.61	$ (0.67)	-2.4%	$ 102.93	$ 102.30	$ (0.63)	-0.6%
Residential	357	-	$ 26.19	$ 27.61	$ 1.42	5.4%	$ 63.07	$ 63.95	$ 0.88	1.4%
GS < 50 kW	2,000	-	$ 53.36	$ 46.69	$ (6.67)	-12.5%	$ 262.81	$ 255.37	$ (7.44)	-2.8%
GS >50 to 999 kW Interval <1000	20,000	60	$ 332.76	$ 318.00	$ (14.76)	-4.4%	$ 3,512.04	$ 3,423.14	$ (88.90)	-2.5%
GS >50 to 999 kW	20,000	60	$ 332.76	$ 318.00	$ (14.76)	-4.4%	$ 3,496.48	$ 3,420.69	$ (75.79)	-2.2%
GS >1,000 to 4,999	800,000	2,000	$ 7,956.38	$ 8,453.67	$ 497.29	6.3%	$134,337.28	$ 126,050.38	$ (8,286.90)	-6.2%
Unmetered Scattered Load	100	-	$ 4.37	$ 7.24	$ 2.87	65.7%	$ 14.84	$ 17.78	$ 2.94	19.8%
Sentinel Lighting	10,000	29	$ 1,227.30	$ 1,696.61	$ 469.31	38.2%	$ 2,378.60	$ 2,774.43	$ 395.83	16.6%
Street Lighting	600,000	176	$12,373.13	$ 8,230.18	$ (4,142.95)	-33.5%	$104,532.03	$ 92,813.32	$ (11,718.71)	-11.2%
EMB - BPI	50,000	27	$ 203.08	$ 317.71	$ 114.63	56.4%	$ 7,849.35	$ 7,229.70	$ (619.65)	-7.9%
EMB - HON #1	1,300,000	2,340	$ 9,292.48	$ 2,356.44	$ (6,936.04)	-74.6%	$212,927.34	$ 186,464.55	$ (26,462.79)	-12.4%
EMB - HON #2	1,990,000	4,050	$ 96.98	$ 57.39	$ (39.59)	-40.8%	$276,731.57	$ 268,125.65	$ (8,605.92)	-3.1%

The Total Bill impacts shown assumes the Board accepts the Applicant's proposals on the unsettled issues and includes updates made to: (i) Group 1 DVAs (reallocations between the Cost of Power & Global Adjustment Accounts 1588 and 1589); (ii) the deferral of the disposition of the Gain on Sale of the Paris facility (Sub account 1508); and (iii) the evidence with respect to Sub Account 1508 for Incremental Monthly Billing. Energy+ notes that Total Bill impacts may change depending upon the OEB's determination of any unsettled issues.

Table 4 – Summary of Capital Expenditures & OM&A

Description		Application	Interrogatories	Variance	Settlement	Variance
Capital Expenditures	Gross Fixed Asset Additions	$ 16,886,408	$ 12,486,408	$ (4,400,000)	$ 13,344,427	$ 858,019
	Net Fixed Asset Additions	$ 16,069,408	$ 11,669,408	$ (4,400,000)	$ 11,378,277	$ (291,131)
OM&A		$ 18,818,358	$ 18,623,358	$ (195,000)	$ 18,453,358	$ (170,000)

Note: Gross Fixed Asset additions are before capital contributions (deferred revenue); Net Fixed Asset additions include capital contributions (deferred revenue).

Finally, Energy+, CCC, VECC and SEC agree as part of the Revenue Requirement Settlement that the effective date of the rates resulting from this Settlement Proposal, and out of the OEB's decision on the outstanding matters arising, should be January 1, 2019.

The Parties note that this Settlement Proposal, including all tables, appendices and the live Excel models represent the evidence and the settlement between the Parties at the time of filing the Settlement Proposal; however, some evidence may need to be updated as a result of the OEB's determination of the unsettled issues**.**

The Parties note that the OEB's determination of the issue related to the proposed Standby Charges, as well as other unsettled issues, is expected to have impacts on the load forecast component of the Revenue Requirement Settlement. There may also be related impacts to the CDM adjustment and the LRAMVA threshold value, and the resulting billing determinants.

A Revenue Requirement Work Form, incorporating all of the changes agreed in this Settlement Proposal, but assuming for all purposes the unsettled issues are as filed in the interrogatory responses, is annexed as Appendix A. The assumption in that document, of the unsettled issues as filed, is not intended by any of the Parties to be indicative of the appropriateness of that assumption, but is instead intended as a placeholder pending the OEB's determination on the issues at the hearing.

Based on the foregoing, and the evidence and rationale provided below, the supporting Parties noted below agree this Settlement Proposal is appropriate and recommend its acceptance by the OEB. TMMC[2] and HONI take no position on the Revenue Requirement Settlement. HONI and TMMC reserve the right to take any position they choose on the remaining unsettled issues.

Summary of Unsettled (and Partially Settled) Issues

The issues not settled or partially settled, and the reasons thereto are as follows:

- **Southworks Advanced Capital Module Request (Issue 1.1)** – The Parties were unable to agree that the Energy+ request for 2022 ACM funding for the proposed Southworks facility is appropriate. Energy+ will, shortly after filing this Settlement Proposal, file additional evidence relating to an update in the forecast costs of the facility.

[2] TMMC taking "No Position" on the Partial Settlement of Issue 3.1 (Load Forecast) is subject to the understanding that the load forecast agreed upon by the supporting Parties may change as a direct result of the Board's disposition of certain issues that remain unsettled.

- **Load Forecast (Issue 3.1) -** This issue has been partially settled, subject to the qualification described below. Energy+, CCC, SEC and VECC reached agreement on the customer counts, the load forecast and related loss factor. TMMC[3] and Hydro One took no position on these matters. However, the Board's determination on the unsettled issues could affect the final load forecast, including the large user Standby adjustment, the CDM adjustments and the LRAMVA threshold value, and the resulting billing determinants.

- **Cost Allocation (Issue 3.2) -** The Parties were unable to agree that Energy+'s proposed cost allocation methodology, allocations, and revenue-to-cost ratios are appropriate. As described further below, the Parties agree that a technical conference focused on this issue should be held in advance of the oral hearing to help bring additional clarity in advance of the oral hearing.

- **Rate Design (Issue 3.3)** - The Parties were unable to agree that the Applicant's proposals for rate design, including the proposal for distribution rate harmonization, are appropriate. The Parties were also unable to agree with the proposed loss factor adjustments to be applied for billing purposes. As described further below, the Parties agree that a technical conference focused on this issue should be held in advance of the oral hearing to help bring additional clarity in advance of the oral hearing.

- **Residential Rate Design (Issue 3.4)** - The Parties were unable to agree that the applicant appropriately applied the OEB's policy on residential rate design. There may be a mitigation issue for low use residential consumers, depending on the resolution of the other unsettled issues.

- **Retail Transmission Service Rates and LV Rates (Issue 3.5)** - The Parties were unable to agree that the proposed Retail Transmission Service Rates and LV Rates are appropriate.

- **Gross Load Billing for Retail Transmission Rates for customers who have load displacement generation (Issue 3.6) -** The Parties were unable to agree that the proposal for using gross load billing for Retail Transmission Rates for customers who have load displacement generation is appropriate.

[3] Ibid.

- **Standby Charge for Large Use customer classes with load displacement (Issue 3.7) –** The Parties were unable to agree that the Applicant's proposal for implementing a standby charge for the Large Use, GS 1,000 to 4,999 Kw and GS 50 to 999 kW customer classes with load displacement facilities is appropriate.

- **LRAMVA and Group 2 Deferral and Variance Accounts (Issue 4.2)** - The Parties were unable to agree that the Applicant's proposals for Group 2 deferral and variance accounts, including the balances in the existing accounts and their disposition, and the continuation of existing accounts, are appropriate. Without limiting the generality of the foregoing, Intervenors have concerns with the LRAMVA (1568), Monthly Billing Sub-Account (1508), OEB Cost Assessment Sub-Account (1508), and the proposal to dispose of Group 2 DVAs on a rate zone harmonized basis.

Proposal to Address Remaining Issues

The Parties agree that the unsettled and partially settled issues would be most efficiently disposed of by way of an oral hearing.

Shortly after filing this Settlement Proposal, Energy+ will file two updates to the evidence. The first update relates to the forecasted costs associated with its proposed ACM for the Southworks facility (which have recently changed) (Issue 1.1). The second relates to quantifying the efficiencies achieved as a result of the transition to monthly billing (Issue 4.2).

The Parties agree that additional discovery on cost allocation, rate design, and the evidence update would be appropriate prior to the start of the oral hearing. This additional discovery will ensure the Board has the most current and accurate information available prior to the start of the oral hearing. It will also ensure that all Parties are given an opportunity to further clarify the evidence on cost allocation and explore any changes arising from the evidence update.

The Parties agree that a transcribed technical conference, would be the most efficient means of conducting this additional discovery. Should the Board panel not agree with the proposal to hold a technical conference, the Parties agree in the alternative that, at a minimum, additional written discovery on cost allocation and the evidence update should be permitted.

1. PLANNING

1.1 Capital

Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

- *customer feedback and preferences*
- *productivity*
- *benchmarking of costs*
- *reliability and service quality*
- *impact on distribution rates*
- *trade-offs with OM&A spending*
- *government-mandated obligations*
- *the objectives of the Applicant and its customers*
- *the distribution system plan, and*
- *the business plan.*

Partial Settlement: For the purposes of the settlement of certain issues in this proceeding, Energy+ agrees to adjust its 2019 opening rate base and Test Year capital plan to reflect the following changes:

- Energy+ agrees to the revised 2019 opening rate base of $154,777,245, reflecting the most current information available on 2018 capital expenditures as detailed in Appendices C and D; and

- Energy+ agrees to the updated 2019 capital expenditures, reflecting the most current information available on 2019 planned capital expenditures as detailed in Appendices C and D; and

- Energy+ agrees to a net reduction in its updated Test Year capital additions of $300,000. This would result in 2019 Capital Additions of $11,378,277.

All consequential changes to the Energy+ five (5) year capital plan are more fully shown in the updated Appendix 2-AB attached as Appendix B to this Settlement Proposal.

Energy+ confirms that this settlement on capital will not compromise the safe and reliable operation of the distribution system in the Test Year.

Energy+ also agrees to withdraw its request for 2020 Advanced Capital Module funding for its proposed Garden Avenue facility in Brantford, which will be a shared facility with Brantford Power Inc. Energy+ agrees with the supporting Parties noted below that it would be more efficient for the Board to consider the entire Garden Avenue facility at the same time and to reduce the possibility of inconsistent decisions. The supporting Parties noted below expect that Energy+ will submit an Incremental Capital Module request, together with a request to dispose the gain on sale of the Paris facility, concurrently with Brantford Power Inc.'s Incremental Capital Module application[4]. The supporting Parties noted below agree that Energy+ should withdraw its proposal to dispose of the gain $402,807 included in Account 1508 arising from the sale of Paris property, on the basis that this gain should be considered together with the incremental costs associated with the transition to the Garden Avenue facility.

With the above adjustment, and subject to the unsettled issue noted below, the supporting Parties noted below accept that the level of planned capital additions and capital expenditures, and the rationale for planning and pacing choices are appropriate and adequately explained, giving due consideration to:

- The customer feedback and preferences and customer objectives as more fully detailed in Exhibit 1 at Section 1.3 and Exhibit 2, Appendix 2-1 DSP, Section 4.1.8;
- The past and planned productivity initiatives of Energy+ as more fully detailed in Exhibit 1 at Section 1.2 and Section 1.4;
- Energy+'s benchmarking performance as more fully detailed in Exhibit 1 at Section 1.2.3 and Section 1.6 (the excel model attached as 2019 EnergyPlus Benchmarking – Spreadsheet-Forecast-Model-Settlement.xlsx provides an updated Energy+ Benchmarking Forecast);

[4] In its 2019 IRM application (EB-2018-0020) Branford Power Inc. has indicated that it plans to file an ICM application for 2020 rates related to its Facility Relocation Project (see Application Pre-Filed Evidence, p.15).

- Energy+'s past reliability and service quality performance as well as Energy+'s targets for performance in the Test Year as more fully detailed in Exhibit 1 at Section 1.2.3, Section 1.6.3 and Exhibit 2 at Section 2.11, and Appendix 2-1 DSP;

- The total impact on distribution rates, as more fully detailed in Table 3 of this Settlement Proposal and the following live Excel models:

  - 2019 EnergyPlus Tariff_Schedule_Model-CND – Settlement.xlsx

  - 2019 EnergyPlus Tariff_Schedule_Model-BCP – Settlement.xlsx

- The settlement on OM&A as described under issue 1.2 of this Settlement Proposal;

- Energy+'s performance meeting government mandated obligations as more fully detailed in Exhibit 1 Section 1.2;

- Energy+'s targets and objectives as more fully detailed in Exhibit 1 at Section 1.2, Section 1.5, and Section 1.6.3.1, and Exhibit 2, Appendix 2-1 DSP, Section 2.3;

- Energy+'s Distribution System Plan, as updated in Appendix B to reflect this settlement; and

- Energy+'s business plan as more fully detailed in Exhibit 1 Section 1.5 and Appendix 1-1.

The supporting Parties noted below acknowledge that this settlement may be affected by the Board's determination of the unsettled issues. In particular, the agreed to rate base in 2018 for the former BCP excludes amounts attributable to stranded meters of $107,068. This amount is currently reflected in a Group 2 DVA, which is going to hearing. The supporting Parties noted below agree that if the Board does not approve disposition of the Group 2 DVA associated with stranded meters, then the 2018 fixed assets should be revised accordingly.

Evidence:

Application: Exhibit 1 Section 1.2.7, Section 1.6.3, Exhibit 2 Sections 2.0 through 2.7, Appendix 2-1 through Appendix 2-8.

IRRs: 2-Staff-17, 2-Staff-18, 2-Staff-19, 2-Staff-20, 2-Staff-21, 2-Staff-22, 2-Staff-23, 2-Staff-24, 2-Staff-25, 2-Staff-26, 2-Staff-27, 2-Staff-28, 2-Staff-29, 2-Staff-30, 2-Staff-31, 2-Staff-32, 2-Staff-33, 2-Staff-34, 2-Staff-35, 2-Staff-36, 2-Staff-37, 2-Staff-38, 2-Staff-39, 2-Staff-40, 2-Staff-41, 2-Staff-42, 2-Staff-43, 2-Staff-44, 2-Staff-45, 2-Staff-46, 2-Staff-47, 2-Staff-48, 2-Staff-49, 2-Staff-50, 2-VECC-4, 2-VECC-5, 2-VECC-6, 2-VECC-7, 2-VECC-10, 2-VECC-11, 2-VECC-12, 2-VECC-13, 2-SEC-14, 2-SEC-15, 2-SEC-16, 2-SEC-17, 2-SEC-18, 2-SEC-19, 2-SEC-20, 2-SEC-21, 2-SEC-22, 2-SEC-23, 2-SEC-24, 2-SEC-25, 2-SEC-26, CCC-8, CCC-9, CCC-10, CCC-11, CCC-12, CCC-13, CCC-14, CCC-15, CCC-16, CCC-17, CCC-18, CCC-19, CCC-20, CCC-21, CCC-22, CCC-23, CCC-24, CCC-25, CCC-26, CCC-27, CCC-28, CCC-29

Appendices to this Settlement Proposal: Appendix B, Appendix C, Appendix D, Appendix E

Models: 2019 EnergyPlus Chapter2_Appendices – Settlement.xlsm

Supporting Parties: Energy+, CCC, VECC, SEC.

Parties taking no Position: TMMC and HONI.

Remaining Unsettled Issue:

The Parties were unable to agree on the request for ACM funding in 2022 for the proposed Southworks facility.

The Parties agree that shortly after the filing of this Settlement Proposal, Energy+ will file updated evidence related to the forecasted costs associated with its proposed Southworks facility (which, since the filing of the interrogatory responses, have increased).

The Parties agree that an additional round of discovery on this updated evidence would be appropriate prior to the start of the oral hearing. This approach is intended to ensure the Board has the most current and accurate information available prior to the oral hearing, and Parties have an opportunity to explore any changes.

1.2 OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to:

- *customer feedback and preferences*
- *productivity*
- *benchmarking of costs*
- *reliability and service quality*
- *impact on distribution rates*
- *trade-offs with capital spending*
- *government-mandated obligations*
- *the objectives of the Applicant and its customers*
- *the distribution system plan, and*
- *the business plan.*

Complete Settlement: For the purposes of the settlement of all of the issues in this proceeding, Energy+ agrees to reduce its proposed OM&A expenses in the Test Year by $170,000 to $18,453,358.

Based on the foregoing, and the evidence filed by Energy+, the supporting Parties noted below agree that the level of planned OM&A expenditures and the rationale for planning and pacing choices are appropriate and adequately explained, giving due consideration to:

- The customer feedback and preferences and customer objectives as more fully detailed in Exhibit 1 at Section 1.3 and Exhibit 2, Appendix 2-1 [DSP], Section 4.1.8;

- The past and planned productivity initiatives of Energy+ as more fully detailed in Exhibit 1 at Sections 1.2 and Sections 1.4;

- Energy+'s benchmarking performance as more fully detailed in Exhibit 1 at Section 1.2.3, and Section 1.6 (the excel model attached as 2019 EnergyPlus Benchmarking – Spreadsheet-Forecast-Model-Settlement.xlsx provides an updated Energy+ Benchmarking Forecast);

- Energy+'s past reliability and service quality performance as well as Energy+'s targets for performance in the Test Year as more fully detailed in Exhibit 1 at Section 1.2.3 and Exhibit 2 at Section 2.11, and Appendix 2-1 DSP;

- The total impact on distribution rates, as more fully detailed in Table 3 of this Settlement Proposal and the following live Excel models:

  - 2019 EnergyPlus Tariff_Schedule_Model-CND – Settlement.xlsx

  - 2019 EnergyPlus Tariff_Schedule_Model-BCP – Settlement.xlsx

- The settlement on capital as described under issue 1.1 of this Settlement Proposal;

- Energy+'s performance meeting government mandated obligations as more fully detailed in Exhibit 1 Section 1.2.1;

- Energy+'s targets and objectives as more fully detailed in Exhibit 1 at Section 1.2 and Section 1.6.3.1 and Exhibit 2, Appendix 2-1 DSP, Section 2.3;

- Energy+'s Distribution System Plan, as updated in Appendix B to reflect this settlement; and

- Energy+'s business plan as more fully detailed in Exhibit 1 Section 1.5 and Appendix 1-1.

The Intervenors noted below found the response to interrogatory 4–SEC-35 which provided the historic and bridge year OM&A including amounts for monthly billing and OEB fees that were recorded in deferral account 1508, but were incurred by Energy+ to be informative in their willingness to accept this settlement.

Energy+ confirms that this settlement on OM&A will not compromise the safe and reliable operation of the distribution system in the Test Year.

Evidence:

Application: Exhibit 1 Sections 1.2 through 1.6, Section 1.2.8, Section 1.6.3.3, Exhibit 4 Sections 4.1 through 4.8, Appendix 4-1, Appendix 4-2, Appendix 4-3

IRRs: 4-Staff-60, 4-Staff-62, 4-Staff-63, 4-Staff-73, 4-SEC-31, 4-SEC-32, 4-SEC-33, 4-SEC-34, 4-SEC-35, 4-VECC-28, 4-VECC-29, 4-VECC-30, 4-VECC-31, 4-VECC-32, 4-VECC-33, 4-VECC-34, 4-VECC-36, 4-VECC-37, 4-VECC-38, 4-VECC-39, 4-VECC-40, CCC-1, CCC-3, CCC-29, CCC-30, CCC-31, CCC-30, CCC-33, CCC-34, CCC-35, CCC-36, CCC-37, CCC-38, CCC-39, CCC-40, CCC-41, CCC-42, CCC-43, CCC-44, CCC-45

Appendices to this Settlement Proposal: Appendix E

Models: 2019 EnergyPlus Chapter2_Appendices – Settlement.xlsm

Supporting Parties: Energy+, CCC, VECC, SEC.

Parties taking no Position: TMMC and HONI.

2. REVENUE REQUIREMENT

2.1 Revenue Requirement Components

Are all elements of the Revenue Requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?

Complete Settlement: The supporting Parties noted below agree that all elements of the Base Revenue Requirement are reasonable, and have been correctly determined in accordance with Board policies and practices. Specifically:

a) *Rate Base:* The supporting Parties noted below agree that the rate base calculations using revised 2019 opening values and accounting for the 2019 capital forecast, reflecting the revised continuity statements filed as Appendix C to this Settlement Proposal and as updated to reflect this Settlement Proposal, are reasonable and have been appropriately determined in accordance with OEB policies and practices.

b) *Working Capital:* The supporting Parties noted below agree that the working capital calculations, revised to reflect the new cost of capital published by the OEB for January 1, 2019 rates, as updated to reflect this Settlement Proposal, are reasonable and have been appropriately determined in accordance with OEB policies and practices.

c) *Cost of Capital:* The supporting Parties noted below agree that the cost of capital calculations, as updated to reflect this Settlement Proposal and the Board's November 22, 2018 cost of capital parameter update for 2019 rates, are reasonable and have been appropriately determined in accordance with OEB policies and practices.

d) *Other Revenue:* The supporting Parties noted below agree that Energy+ will increase other revenue forecast in the Test Year by $100,000 to account for incremental bank interest earned on savings above what was originally forecasted. Subject to these adjustments, the Parties agree that the other revenue calculations, as updated to reflect this Settlement Proposal and in particular the Board's decision on specific service charges, are reasonable and have been appropriately determined in accordance with OEB policies and practices.

- Energy+ notes that the change in other revenue in the RRWF shows to be greater than $100,000 as a result of changes in the amortization of deferred revenue.

e) *Depreciation:* The supporting Parties noted below agree that the depreciation calculations, as updated to reflect this Settlement Proposal, are reasonable and have been appropriately determined in accordance with OEB policies and practices.

f) *Taxes:* The supporting Parties noted below agree that the PILs calculations, as updated to reflect this Settlement Proposal, are reasonable and have been appropriately determined in accordance with OEB policies and practices.

Evidence:

Application: Exhibit 1 Section 1.2.4.1, Sections 1.2.7 through 1.2.9; Exhibit 2 Sections 2.0 through 2.5, Sections 2.7 and Sections 2.8, Exhibit 2 Appendices 2-1 to 2-9; Exhibit 3 Section 3.1.1.2, Section 3.1.3, Section 3.4, and Appendix 3-5; Exhibit 4 Sections 4.9 and 4.10 and Appendices 4-4, 4-5, and 4-8; Exhibit 5 Sections 5.1 and 5.2, Exhibit 5 Appendices 5-1 to 5-5.; Exhibit 6

IRRs: 2-Staff-17, 2-Staff-18, 2-Staff-19, 2-Staff-20, 2-Staff-21, 2-Staff-22, 2-Staff-23, 2-Staff-24, 2-Staff-25, 2-Staff-26, 2-Staff-27, 2-Staff-28, 2-Staff-29, 2-Staff-30, 2-Staff-31, 2-Staff-32, 2-Staff-33, 2-Staff-34, 2-Staff-35, 2-Staff-36, 2-Staff-37, 2-Staff-38, 2-Staff-39, 2-Staff-40, 2-Staff-41, 2-Staff-42, 2-Staff-43, 2-Staff-44, 2-Staff-45, 2-Staff-46, 2-Staff-47, 2-Staff-48, 2-Staff-49, 2-Staff-50, 3-Staff-56, 3-Staff-57, 4-Staff-60, 4-Staff-62, 4-Staff-63, 4-Staff-73, 4-Staff-74, 6-Staff-75, 2-SEC-14, 2-SEC-15, 2-SEC-16, 2-SEC-17, 2-SEC-18, 2-SEC-19, 2-SEC-20, 2-SEC-21, 2-SEC-22, 2-SEC-23, 2-SEC-24, 2-SEC-25, 2-SEC-26, 2-VECC-10, 2-VECC-11, 2-VECC-12, 2-VECC-13, 2-VECC-4, 2-VECC-5, 2-VECC-6, 2-VECC-7, 3-SEC-28, 3-SEC-29, 3-SEC-30, 4-SEC-31, 4-SEC-32, 4-SEC-33, 4-SEC-34, 4-SEC-35, 5-SEC-37, 5-SEC-38, 3-VECC-26, 3-VECC-27, 4-VECC-28, 4-VECC-29, 4-VECC-30, 4-VECC-31, 4-VECC-32, 4-VECC-33, 4-VECC-34, 4-VECC-36, 4-VECC-37, 4-VECC-38, 4-VECC-39, 4-VECC-40, 5-VECC-42, 5-VECC-43, CCC-1, CCC-5, CCC-8, CCC-9, CCC-10, CCC-11, CCC-12, CCC-13, CCC-14, CCC-15, CCC-16, CCC-17, CCC-18, CCC-19, CCC-20, CCC-21, CCC-22, CCC-23, CCC-24, CCC-25, CCC-26, CCC-27, CCC-28, CCC-29, CCC-3, CCC-30, CCC-31, CCC-33, CCC-34, CCC-35, CCC-36, CCC-37, CCC-38, CCC-39, CCC-40, CCC-41, CCC-42, CCC-43, CCC-44, CCC-45

Appendices to this Settlement Proposal: Appendix A, Appendix B, Appendix C, Appendix D, Appendix E

Models: 2019 EnergyPlus Rev_Reqt_Work_form - Settlement.xls, 2019 EnergyPlus Test_year-Income_Tax_PILs_Workform_V1 - Settlement.xls

Supporting Parties: Energy+, CCC, VECC, SEC.

Parties taking no Position: TMMC and HONI.

2.2 Revenue Requirement Determination

Has the Revenue Requirement been accurately determined based on these elements?

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the supporting Parties noted below agree that the proposed Revenue Requirement has been accurately determined as set forth in more detail in the Appendices.

Evidence:

Application: Exhibit 1 Section 1.2.4.1, Sections 1.2.7 through 1.2.9; Exhibit 2 Sections 2.0 through 2.5, Sections 2.7 and Sections 2.8, Exhibit 2 Appendices 2-1 to 2-9; Exhibit 3 Section 3.1.1.2, Section 3.1.3, Section 3.4, and Appendix 3-5; Exhibit 4 Sections 4.9 and 4.10 and Appendices 4-4, 4-5, and 4-8; Exhibit 5 Sections 5.1 and 5.2, Exhibit 5 Appendices 5-1 to 5-5.; Exhibit 6

IRRs: 2-Staff-17, 2-Staff-18, 2-Staff-19, 2-Staff-20, 2-Staff-21, 2-Staff-22, 2-Staff-23, 2-Staff-24, 2-Staff-25, 2-Staff-26, 2-Staff-27, 2-Staff-28, 2-Staff-29, 2-Staff-30, 2-Staff-31, 2-Staff-32, 2-Staff-33, 2-Staff-34, 2-Staff-35, 2-Staff-36, 2-Staff-37, 2-Staff-38, 2-Staff-39, 2-Staff-40, 2-Staff-41, 2-Staff-42, 2-Staff-43, 2-Staff-44, 2-Staff-45, 2-Staff-46, 2-Staff-47, 2-Staff-48, 2-Staff-49, 2-Staff-50, 3-Staff-56, 3-Staff-57, 4-Staff-60, 4-Staff-62, 4-Staff-63, 4-Staff-73, 4-Staff-74, 6-Staff-75, 2-SEC-14, 2-SEC-15, 2-SEC-16, 2-SEC-17, 2-SEC-18, 2-SEC-19, 2-SEC-20, 2-SEC-21, 2-SEC-22, 2-SEC-23, 2-SEC-24, 2-SEC-25, 2-SEC-26, 2-VECC-10, 2-VECC-11, 2-VECC-12, 2-VECC-13, 2-VECC-4, 2-VECC-5, 2-VECC-6, 2-VECC-7, 3-SEC-28, 3-SEC-29, 3-SEC-30, 4-SEC-31, 4-SEC-32, 4-SEC-33, 4-SEC-34, 4-SEC-35, 5-SEC-37, 5-SEC-38, 3-VECC-26, 3-VECC-27, 4-VECC-28, 4-VECC-29, 4-VECC-30, 4-VECC-31, 4-VECC-32, 4-VECC-33, 4-VECC-34, 4-VECC-36, 4-VECC-37, 4-VECC-38, 4-VECC-39, 4-VECC-40, 5-VECC-42, 5-VECC-43, CCC-1, CCC-5, CCC-8, CCC-9, CCC-10, CCC-11, CCC-12, CCC-13, CCC-14, CCC-15, CCC-16, CCC-17, CCC-18, CCC-19, CCC-20, CCC-21, CCC-22, CCC-23, CCC-24, CCC-25, CCC-26, CCC-27, CCC-28, CCC-29, CCC-3, CCC-30, CCC-31, CCC-33, CCC-34, CCC-35, CCC-36, CCC-37, CCC-38, CCC-39, CCC-40, CCC-41, CCC-42, CCC-43, CCC-44, CCC-45

Appendices to this Settlement Proposal: Appendix A, Appendix B, Appendix C, Appendix D, Appendix E

Models: EnergyPlus_2019_Settlement_Rev_Reqmt_Worform - Settlement.xls

Supporting Parties: Energy+, CCC, VECC, SEC.

Parties taking no Position: TMMC and HONI.

3. LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

3.1 Load Forecast

Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the number and energy and demand requirements of the applicant's customers?

Partial Settlement: For the purposes of the settlement of all of the issues in this proceeding, Energy+ agrees to adopt a load forecast of 1,653,951,480 kWh and a customer forecast of 82,897, as shown in Table 5. The Parties noted as supporting this partial settlement below agree that the customer forecast, load forecast, related loss factors, CDM adjustments and the resulting billing determinates are appropriate, subject to the qualification noted below, and are reflective of the energy and demand requirements of the applicant's customers.

The agreed to load forecast is presented below as Table 5:

Table 5 – Load Forecast

Customer Class	Application	Interrogatories	Variance	Settlement	Variance
Residential					
Customers	58,677	58,677	-	58,677	-
kWh	466,068,279	461,453,716	(4,614,563)	461,453,716	-
General Service < 50 kW					
Customers	6,451	6,451	-	6,451	-
kWh	195,276,256	193,967,011	(1,309,245)	193,967,011	-
General Service > 50 to 999 kW					
Customers	800	800	-	800	-
kWh	493,112,062	491,288,356	(1,823,706)	491,288,356	-
kW	1,556,242	1,550,487	(5,756)	1,550,487	-
General Service > 1000 to 4999 kW					
Customers	27	27	-	27	-
kWh	231,017,192	229,378,990	(1,638,202)	229,378,990	-
kW	542,178	538,334	(3,845)	538,334	-
Large User					
Customers	2	2	-	2	-
kWh	145,503,126	145,141,006	(362,119)	145,141,006	-
kW	382,038	361,276	(20,762)	361,276	-
Direct Market Participant					
Customers	4	4	-	4	-
kW	67,942	67,942	-	67,942	-
Street Lights					
Connections	16,260	16,260	-	16,260	-
kWh	5,367,464	3,798,281	(1,569,184)	3,798,281	-
kW	15,467	10,945	(4,522)	10,945	-
Sentinel Lights					
Connections	168	168	-	168	-
kWh	126,989	126,989	-	126,989	-
kW	343	343	-	343	-
Unmetered Loads					
Connections	499	499	-	499	-
kWh	2,273,988	2,273,988	-	2,273,988	-
Embedded Distributor - Hydro One, CND					
Customers	2	2	-	2	-
kWh	12,605,162	12,605,162	-	12,605,162	-
kW	24,387	24,387	-	24,387	-
Embedded Distributor - Waterloo North, CND					
Customers	1	1	-	1	-
kWh	58,104,381	58,104,381	-	58,104,381	-
kW	114,657	114,657	-	114,657	-
Embedded Distributor - Brantford Power, BCP					
Customers	1	1	-	1	-
kWh	347,757	347,757	-	347,757	-
kW	1,075	1,075	-	1,075	-
Embedded Distributor - Hydro One #1, BCP					
Customers	1	1	-	1	-
kWh	12,191,720	12,191,720	-	12,191,720	-
kW	29,995	29,995	-	29,995	-
Embedded Distributor - Hydro One #2, BCP					
Customers	4	4	-	4	-
kWh	43,274,122	43,274,122	-	43,274,122	-
kW	102,973	102,973	-	102,973	-
Total					
Customer/Connections	82,897	82,897	-	82,897	-
kWh	1,665,268,498	1,653,951,480	(11,317,018)	1,653,951,480	-
kW	2,837,297	2,802,414	(34,884)	2,802,414	-

The CDM savings are shown in Table 6 below:

Table 6 – 2019 Expected CDM Savings by Rate Class for LRAM Variance Account

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

Evidence:

Application: Exhibit 1 Section 1.2.6, Exhibit 3.2, Exhibit 3.3, Exhibit 7 Section 7.0, Section 7.1.1, Section 7.1.2, Appendix 74-1

IRRs: 3-Staff-51, 3-Staff-52, 3-Staff-53, 3-Staff-54, 3-Staff-55, 3-Staff-58, 3-Staff-59, 3-VECC-15, 3-VECC-16, 3-VECC-17, 3-VECC-18, 3-VECC-19, 3-VECC-20, 3-VECC-22, 3-VECC-23, 3-VECC-24, 3-VECC-25

Appendices to this Settlement Proposal: Appendix A

Models: 2019 EnergyPlus Load Forecast Model – Settlement.xlsx, 2019 EnergyPlus Load profile model 2006 Hydro One data for 2019 – Settlement.xlsm

Supporting Parties: Energy+, CCC, VECC, SEC.

Parties taking no Position: TMMC[5] and HONI.

Remaining Unsettled Issue:

The Parties agree that the load forecast, CDM adjustment and the LRAMVA threshold value should be adjusted to reflect the Board's final determination on the unsettled issues (for example, Standby Charge and LRAMVA).

[5] Supra note 2.

3.2 Cost Allocation

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

No Settlement: The Parties have been unable to reach a settlement on this issue.

The impact of the Revenue Requirement Settlement on Applicant's proposal in respect of this issue is shown in Table 7 below.

Table 7 – Revenue-to-Cost Ratios

Customer Class	Cost Ratios from 2019 Cost Allocation Model - Line 75 Tab O1	Proposed Revenue to Cost Ratio	Board Target Low	Board Target High
Residential	85.40%	91.82%	85.00%	115.00%
General Service < 50 kW	108.67%	108.67%	80.00%	120.00%
General Service > 50 to 999 kW	140.27%	120.00%	80.00%	120.00%
General Service > 1000 to 4999 kW	113.54%	113.54%	80.00%	120.00%
Large User	100.66%	100.66%	85.00%	115.00%
Street Lights	150.76%	120.00%	80.00%	120.00%
Unmetered Loads	89.73%	91.82%	80.00%	120.00%
Sentinel Lights	69.62%	91.82%	80.00%	120.00%
Embedded Distributor - Hydro One, CND	120.86%	100.00%	80.00%	120.00%
Embedded Distributor - Waterloo North, CND	144.82%	100.00%	80.00%	120.00%
Embedded Distributor - Hydro One #1, BCP	401.35%	100.00%	80.00%	120.00%
Embedded Distributor - Brantford Power, BCP	44.58%	100.00%	80.00%	120.00%
Embedded Distributor - Hydro One #2, BCP	167.88%	100.00%	80.00%	120.00%

3.3 Rate Design

Are the applicant's proposals for rate design appropriate, including the proposal for distribution rate harmonization?

No Settlement: The Parties have been unable to reach a settlement on this issue.

The impact of the Revenue Requirement Settlement on the Applicant's proposals in respect of this issue is shown in Table 8 below.

Table 8 – Distribution Charges

Customer Class	2019 Distribution Rates Application	2019 Distribution Rates Interrogatories	Variance	2019 Distribution Rates Settlement	Variance	2019 Fixed/Variable Split
Residential						
Monthly Service Charge	27.33	27.84	0.51	27.61	(0.23)	100.00%
Distribution Volumetric per kWh	-	-	-	-	-	0.00%
General Service < 50 kW						
Monthly Service Charge	15.18	15.00	(0.18)	14.89	(0.11)	27.20%
Distribution Volumetric per kWh	0.0162	0.0160	(0.0002)	0.0159	(0.0001)	72.80%
General Service > 50 to 999 kW						
Monthly Service Charge	111.18	99.10	(12.08)	98.74	(0.36)	14.57%
Distribution Volumetric per kW	4.1019	3.6675	(0.4344)	3.6544	(0.0131)	85.43%
General Service > 1000 to 4999 kW						
Monthly Service Charge	904.08	893.19	(10.89)	886.87	(6.32)	14.54%
Distribution Volumetric per kW	3.8454	3.8061	(0.0393)	3.7834	(0.0227)	85.46%
Large User						
Monthly Service Charge	9,388.05	9,274.94	(113.11)	9,209.36	(65.58)	20.71%
Distribution Volumetric per kW	2.2632	2.3586	0.0954	2.3419	(0.0167)	79.29%
Street Lights						
Monthly Service Charge	1.65	1.90	0.25	1.90	(0.00)	68.88%
Distribution Volumetric per kW	13.3222	15.3069	1.9847	15.2704	(0.0365)	31.12%
Sentinel Lights						
Monthly Service Charge	2.85	2.83	(0.02)	2.82	(0.01)	28.22%
Distribution Volumetric per kW	42.5882	42.2569	(0.3313)	42.1667	(0.0902)	71.78%
Unmetered Loads						
Monthly Service Charge	5.79	5.83	0.04	5.81	(0.02)	51.68%
Distribution Volumetric per kWh	0.0143	0.0143	-	0.0143	-	48.32%
Embedded Distributor - Hydro One, CND						
Monthly Service Charge	-	-	-	-	-	0.00%
Distribution Volumetric per kW	1.9143	1.7459	(0.1684)	1.7543	0.0084	100.00%
Embedded Distributor - Waterloo North, CND						
Monthly Service Charge	-	-	-	-	-	0.00%
Distribution Volumetric per kW	1.4220	1.3509	(0.0711)	1.3628	0.0119	100.00%
Embedded Distributor - Brantford Power, BCP						
Monthly Service Charge	-	-	-	-	-	0.00%
Distribution Volumetric per kW	13.9455	11.7019	(2.2436)	11.7671	0.0652	100.00%
Embedded Distributor - Hydro One #1, BCP						
Monthly Service Charge	59.10	58.48	(0.62)	57.39	(1.09)	2.28%
Distribution Volumetric per kW	1.1177	0.9738	(0.1439)	0.9825	0.0087	97.72%
Embedded Distributor - Hydro One #2, BCP						
Monthly Service Charge	59.10	58.48	(0.62)	57.39	(1.09)	100.00%
Distribution Volumetric per kW	-	-	-	-	-	0.00%

3.4 Residential Rate Design

Has the applicant appropriately applied the OEB's policy on residential rate design?

No Settlement: The Parties have been unable to reach a settlement on this issue.

The impact of the Revenue Requirement Settlement on this issue is shown in Table 9 below.

Table 9 – Rate Impacts

Residential Customer Class	2018 Distribution Rates	2019 Distribution Rates Settlement	Difference $	Difference %
CND Service Territory				
Monthly Service Charge	$ 21.35	$ 27.61	$ 6.26	29.32%
Distribution Volumetric per kWh	$ 0.0046	$ -	$ (0.0046)	-100.00%
Brant County Service Territory				
Monthly Service Charge	$ 24.30	$ 27.61	$ 3.31	13.62%
Distribution Volumetric per kWh	$ 0.0053	$ -	$ (0.0053)	-100.00%

3.5 Retail Transmission Service Rates and LV Rates

Are the proposed Retail Transmission Service Rates and LV Rates appropriate?

No Settlement: The Parties have been unable to reach a settlement on this issue.

3.6 Gross load billing for Retail Transmission Rates for customers who have load displacement generation

Is the proposal for using gross load billing for Retail Transmission Rates for customers who have load displacement generation appropriate?

No Settlement: The Parties have been unable to reach a settlement on this issue.

3.7 Standby Charge for Large Use customer classes with load displacement

Is the proposal for implementing a standby charge for the Large Use, GS 1,000 to 4,999 kW and GS 50 to 999 kW customer classes with load displacement appropriate?

No Settlement: The Parties have been unable to reach a settlement on this issue.

4. ACCOUNTING

4.1 Impacts of Changes

Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?

Complete Settlement: The supporting Parties noted below accept the evidence of Energy+ that the impacts of any changes in accounting standards, policies, estimates and adjustments have been properly identified, and the treatment of each of these impacts is appropriate.

Evidence:

Application: Exhibit 1 Sections 1.2.5.1, Sections 1.9.10, and 1.9.12, Appendix 1-3, Appendix 1-18, Exhibit 4 Sections 4.1.4, 4.1.4.1, 4.1.4.2, 4.9.2, 4.9.2.2, Exhibit 9 Section 9.2, Section 9.1.3, Section 9.1.4

IRRs: 4-Staff-72, 4-Staff-73, 9-Staff-98, 9-Staff-99, 9-Staff-103

Appendices to this Settlement Proposal: None

Models: None

Supporting Parties: Energy+, CCC, VECC, SEC.

Parties Taking No Position: TMMC and HONI.

4.2 Deferral and Variance Accounts

Are the applicant's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, and the continuation of existing accounts appropriate?

Partial Settlement: The Intervenors noted below raised concerns with respect to the appropriate allocation of deferral and variance accounts as between the customers of the former utilities of Cambridge and North Dumfries Hydro and those of Brant County Power. Energy+ confirms that disposition of the Group 1 DVAs separately in each of the Brant County and the CND service territories does not cause a significant difference in the bill impacts (i.e. less than 3% in all cases, except for Waterloo North which is 3.16%) compared to the Energy+ proposal to dispose of Group 1 DVAs on a harmonized basis. On the basis of this understanding, the supporting Parties noted below agree to Energy+'s proposed disposition of the Group 1 DVAs on a harmonized basis. The Group 1 DVA Account Balances are as summarized in Table 10.

The supporting Parties noted below acknowledge that the disposition of Group 1 DVAs will be on an interim basis, consistent with the Board's letter dated July 20, 2018 in which the Board determined that effective immediately the OEB will not approve Group 1 rate riders on a final basis pending the development of further guidance.

As noted in the settlement of issue 1.1 above, the supporting Parties noted below agree that Energy+ will withdraw its proposal to dispose of $402,807 included in Account 1508 arising due to the sale of Paris property, on the basis that this gain should be considered together with the incremental costs associated with the transition to the Garden Avenue facility.

Table 10 – Group 1 DVA Accounts

Group 1 DVA Accounts		Application	Interrogatories	Variance	Settlement	Variance
LV Variance Account	1550	(307,303)	(307,008)	295	(307,008)	-
Smart Metering Entity Charge Variance Account	1551	(16,957)	(16,941)	16	(16,941)	-
RSVA - Wholesale Market Service Charge	1580	(1,699,001)	(1,697,361)	1,640	(1,697,361)	-
Variance WMS – Sub-account CBR Class A	1580	-	-	-	-	-
Variance WMS – Sub-account CBR Class B	1580	7,333	7,322	(10)	7,322	-
RSVA - Retail Transmission Network Charge	1584	(1,322,468)	(1,321,209)	1,259	(1,321,209)	-
RSVA - Retail Transmission Connection Charge	1586	(597,981)	(597,410)	571	(597,410)	-
RSVA - Power (excluding Global Adjustment)	1588	1,235,591	1,234,402	(1,189)	594,222	(640,180)
RSVA - Global Adjustment	1589	319,329	319,023	(306)	959,203	640,180
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	-	-	-	-	-
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	-	-	-	-	-
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	-	-	-	-	-
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	-	-	-	-	-
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	-	-	-	-	-
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	10,834	-	(10,834)	-	-
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	1,330	344,778	343,448	344,778	-
Disposition and Recovery/Refund of Regulatory Balances (2017)	1595	(160,773)	-	160,773	-	-
Total		**(2,530,067)**	**(2,034,405)**	**495,663**	**(2,034,405)**	**-**

Evidence:

Application: Exhibit 1 Section 1.2.11, Exhibit 9 Sections 9.0 through 9.1.6, Sections 9.3.1 through 9.3.2, Sections 9.4.1 through 9.4.2, Sections 9.4.5 through 9.5, Appendix 9-1 through 9-2

IRRs: 9-Staff-96, 9-Staff-97, 9-Staff-100, 9-VECC-59, 9-VECC-60

Appendices to this Settlement Proposal: Appendix E

Models: 2019 EnergyPlus DVA Continuity_Schedule_CoS – Consolidated – Settlement.xlsb, 2019 EnergyPlus GA-Analysis-Workform - Consolidated - Settlement.xlsb

Supporting Parties: Energy+, CCC, VECC, SEC.

Parties taking no Position: TMMC and HONI.

Remaining Unsettled Issue:

The Parties have been unable to reach a settlement on the requested disposition of the Group 2 DVAs. Without limiting the generality of the foregoing, the Intervenors have concerns with the LRAMVA (1568); Monthly Billing Sub-Account (1508), OEB Cost Assessment Sub-Account (1508), and the proposal to dispose of Group 2 DVAs on a harmonized basis.

The Parties agree that Energy+ will file shortly after this Settlement Proposal, updated evidence related to the Monthly Billing Sub-Account (1508) to quantify and reflect the efficiencies achieved as a result of the transition to monthly billing. The Parties agree that an additional round of written discovery limited to this updated evidence would be appropriate prior to the start of the oral hearing. This approach is intended to ensure the board has the most current and accurate information available prior to the oral hearing, and Parties have an opportunity to explore any changes.

The Group 2 DVA Account Balances are as summarized in Table 11.

Table 11 – Group 2 DVA Accounts[6] [7]

Group 2 DVA Accounts		Application	Interrogatories	Variance	Adjusted
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ 25,515	$ 25,494	$ (21)	
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance	1508	$ (239)	$ (239)	$ 0	
Other Regulatory Assets - Sub-Account - Monthly Bills	1508	$ 511,449	$ 510,964	$ (486)	$ 416,346
Other Regulatory Assets - Sub-Account - OEB Cost Assessment	1508	$ 174,428	$ 174,262	$ (165)	
Other Regulatory Assets - Sub-Account - Gain on Sale of Property	1508	$ -	$ (402,807)	$ (402,807)	$ -
Retail Cost Variance Account - Retail	1518	$ 142,626	$ 142,467	$ (159)	
Retail Cost Variance Account - STR	1548	$ 2,582	$ 2,580	$ (2)	
Extra-Ordinary Event Costs	1572	$ (5,870)	$ (5,857)	$ 14	
LRAM Variance Account	1568	$ 1,200,452	$ 1,540,835	$ 340,383	
Renewable Generation Connection Capital Deferral Account	1531	$ 5,582	$ -	$ (5,582)	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ 95,990	$ 95,898	$ (92)	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ 107,169	$ 107,068	$ (101)	
Meter Cost Deferral Account (MIST Meters)	1557	$ 178,670	$ 178,500	$ (170)	
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	$ 1,908,269	$ 1,908,269	$ -	
Accounting Changes Under CGAAP Balance + Return Component	1576	$ (2,456,018)	$ (2,456,018)	$ -	
Total		**$ 1,890,604**	**$ 1,821,418**	**$ (69,187)**	

[6] Energy+ has adjusted the claim amount for Account 1508 Gain on Sale of Property as the Parties agreed that Energy+ should withdraw its proposal to dispose of the account on the basis that the gain should be considered together with the incremental costs associated with the transition to the Garden Avenue facility.

[7] Energy+ has adjusted the claim amount for Account 1508 Monthly Bills to record the estimated cash flow benefit attributable to the transition to monthly billing for 2016 and 2017.

5. OTHER

5.1 Effective Date

Is the proposed effective date (i.e. January 1, 2019) for 2019 rates appropriate?

Complete Settlement: Subject to the Board's acceptance of the balance of this Settlement Proposal, the supporting Parties noted below agree to an effective date of January 1, 2019, for 2019 rates.

Evidence:

Application: Exhibit 1, Section 1.1, Section 1.9.4, Appendix 1-17

IRRs: None.

Appendices to this Settlement Proposal: None.

Models: None.

Supporting Parties: Energy+, CCC, VECC, SEC.

Parties taking no Position: TMMC and HONI.

APPENDIX A

UPDATED REVENUE REQUIREMENT WORK FORM

The following RRWF summary has been updated to reflect this partial settlement.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Version 8.00

Utility Name	Energy + Inc.
Service Territory	*Cambridge, North Dumfries and Brant County*
Assigned EB Number	EB-2018-0028
Name and Title	Sarah Hughes, Chief Financial Officer
Phone Number	519-621-8405, Ext. 2638
Email Address	shughes@energyplus.ca
Test Year	2019
Bridge Year	2018
Last Rebasing Year	2014

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Data Input [1]

		Initial Application	[2]	Adjustments	Settlement Agreement	[6]	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$184,201,142		############	$ 182,594,277			$182,594,277	
	Accumulated Depreciation (average)	($26,210,491)	[5]	$746,309.65	($25,464,181)			($25,464,181)	
	Allowance for Working Capital:								
	Controllable Expenses	$18,355,589		($360,412)	$ 17,995,177			$17,995,177	
	Cost of Power	$157,654,356		$46,953,238	$ 204,607,594			$204,607,594	
	Working Capital Rate (%)	7.50%	[9]		7.50%	[9]		7.50%	[9]
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$33,626,933		($168,713)	$33,458,220		$0	$33,458,220	
	Distribution Revenue at Proposed Rates	$35,170,323		($842,535)	$34,327,788		$0	$34,327,788	
	Other Revenue:								
	Specific Service Charges	$1,765,991		$367,088	$2,133,079		$0	$2,133,079	
	Late Payment Charges	$189,000		$0	$189,000		$0	$189,000	
	Other Distribution Revenue				$ -		$0	$ -	
	Other Income and Deductions	($300,000)		$0	($300,000)		$0	($300,000)	
	Total Revenue Offsets	$1,654,991	[7]	$367,088	$2,022,079		$0	$2,022,079	
	Operating Expenses:								
	OM+A Expenses	$18,575,648		($365,000)	$ 18,210,648			$18,210,648	
	Depreciation/Amortization	$6,703,335		($271,130)	$ 6,432,205			$6,432,205	
	Property taxes	$200,710			$ 200,710			$200,710	
	Other expenses	$42,000			42000			$42,000	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($3,954,470)	[3]		($4,098,966)			($4,098,966)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$585,231			$568,382			$568,382	
	Income taxes (grossed up)	$796,233			$773,309			$773,309	
	Federal tax (%)	15.00%			15.00%			15.00%	
	Provincial tax (%)	11.50%			11.50%			11.50%	
	Income Tax Credits	$ -			0.00%			0.00%	
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	[8]		4.0%	[8]		4.0%	[8]
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)	0.0%			0.0%			0.0%	
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.37%			4.37%			4.37%	
	Short-term debt Cost Rate (%)	2.29%			2.82%			2.82%	
	Common Equity Cost Rate (%)	9.00%			8.98%			8.98%	
	Prefered Shares Cost Rate (%)	0.00%			0.00%			0.00%	

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$184,201,142	($1,606,865)	$182,594,277	$ -	$182,594,277
2	Accumulated Depreciation (average)	(2)	($26,210,491)	$746,310	($25,464,181)	$ -	($25,464,181)
3	Net Fixed Assets (average)	(2)	$157,990,651	($860,556)	$157,130,096	$ -	$157,130,096
4	Allowance for Working Capital	(1)	$13,200,746	$3,494,462	$16,695,208	$ -	$16,695,208
5	**Total Rate Base**		$171,191,397	$2,633,906	$173,825,304	$ -	$173,825,304

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$18,355,589	($360,412)	$17,995,177	$ -	$17,995,177
7	Cost of Power		$157,654,356	$46,953,238	$204,607,594	$ -	$204,607,594
8	Working Capital Base		$176,009,945	$46,592,826	$222,602,772	$ -	$222,602,772
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$13,200,746	$3,494,462	$16,695,208	$ -	$16,695,208

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2018 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Utility Income

Line No.	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$35,170,323	($842,535)	$34,327,788	$ -	$34,327,788
2	Other Revenue [1]	$1,654,991	$367,088	$2,022,079	$ -	$2,022,079
3	Total Operating Revenues	$36,825,314	($475,447)	$36,349,867	$ -	$36,349,867
	Operating Expenses:					
4	OM+A Expenses	$18,575,648	($365,000)	$18,210,648	$ -	$18,210,648
5	Depreciation/Amortization	$6,703,335	($271,130)	$6,432,205	$ -	$6,432,205
6	Property taxes	$200,710	$ -	$200,710	$ -	$200,710
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$42,000	$ -	$42,000	$ -	$42,000
9	Subtotal (lines 4 to 8)	$25,521,693	($636,130)	$24,885,563	$ -	$24,885,563
10	Deemed Interest Expense	$4,344,498	$102,692	$4,447,190	$ -	$4,447,190
11	Total Expenses (lines 9 to 10)	$29,866,191	($533,438)	$29,332,753	$ -	$29,332,753
12	**Utility income before income taxes**	$6,959,123	$57,991	$7,017,114	$ -	$7,017,114
13	Income taxes (grossed-up)	$796,233	($22,924)	$773,309	$ -	$773,309
14	**Utility net income**	$6,162,890	$80,915	$6,243,805	$ -	$6,243,805

Notes

Other Revenues / Revenue Offsets

Note	Item	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
[1]	Specific Service Charges	$1,765,991	$367,088	$2,133,079	$ -	$2,133,079
	Late Payment Charges	$189,000	$ -	$189,000	$ -	$189,000
	Other Distribution Revenue	$ -		$ -	$ -	$ -
	Other Income and Deductions	($300,000)	$ -	($300,000)	$ -	($300,000)
	Total Revenue Offsets	$1,654,991	$367,088	$2,022,079	$ -	$2,022,079

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$6,162,890	$6,243,805	$6,243,805
2	Adjustments required to arrive at taxable utility income	($3,954,470)	($4,098,966)	($4,098,966)
3	Taxable income	$2,208,420	$2,144,839	$2,144,839
	Calculation of Utility income Taxes			
4	Income taxes	$585,231	$568,382	$568,382
6	Total taxes	$585,231	$568,382	$568,382
7	Gross-up of Income Taxes	$211,002	$204,927	$204,927
8	Grossed-up Income Taxes	$796,233	$773,309	$773,309
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$796,233	$773,309	$773,309
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$95,867,182	4.37%	$4,187,687
2	Short-term Debt	4.00%	$6,847,656	2.29%	$156,811
3	**Total Debt**	60.00%	$102,714,838	4.23%	$4,344,498
	Equity				
4	Common Equity	40.00%	$68,476,559	9.00%	$6,162,890
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$68,476,559	9.00%	$6,162,890
7	**Total**	100.00%	$171,191,397	6.14%	$10,507,388
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$97,342,170	4.37%	$4,251,115
2	Short-term Debt	4.00%	$6,953,012	2.82%	$196,075
3	**Total Debt**	60.00%	$104,295,182	4.26%	$4,447,190
	Equity				
4	Common Equity	40.00%	$69,530,121	8.98%	$6,243,805
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$69,530,121	8.98%	$6,243,805
7	**Total**	100.00%	$173,825,304	6.15%	$10,690,995
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$97,342,170	4.37%	$4,251,115
9	Short-term Debt	4.00%	$6,953,012	2.82%	$196,075
10	**Total Debt**	60.00%	$104,295,182	4.26%	$4,447,190
	Equity				
11	Common Equity	40.00%	$69,530,121	8.98%	$6,243,805
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$69,530,121	8.98%	$6,243,805
14	**Total**	100.00%	$173,825,304	6.15%	$10,690,995

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application		Settlement Agreement		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$1,543,390		$869,568		$869,568
2	Distribution Revenue	$33,626,933	$33,626,933	$33,458,220	$33,458,220	$33,458,220	$33,458,220
3	Other Operating Revenue Offsets - net	$1,654,991	$1,654,991	$2,022,079	$2,022,079	$2,022,079	$2,022,079
4	**Total Revenue**	$35,281,924	$36,825,314	$35,480,299	$36,349,867	$35,480,299	$36,349,867
5	Operating Expenses	$25,521,693	$25,521,693	$24,885,563	$24,885,563	$24,885,563	$24,885,563
6	Deemed Interest Expense	$4,344,498	$4,344,498	$4,447,190	$4,447,190	$4,447,190	$4,447,190
8	**Total Cost and Expenses**	$29,866,191	$29,866,191	$29,332,753	$29,332,753	$29,332,753	$29,332,753
9	**Utility Income Before Income Taxes**	$5,415,733	$6,959,123	$6,147,546	$7,017,114	$6,147,546	$7,017,114
10	Tax Adjustments to Accounting Income per 2013 PILs model	($3,954,470)	($3,954,470)	($4,098,966)	($4,098,966)	($4,098,966)	($4,098,966)
11	**Taxable Income**	$1,461,263	$3,004,653	$2,048,580	$2,918,148	$2,048,580	$2,918,148
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$387,235	$796,233	$542,874	$773,309	$542,874	$773,309
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$5,028,498	$6,162,890	$5,604,672	$6,243,805	$5,604,672	$6,243,805
16	**Utility Rate Base**	$171,191,397	$171,191,397	$173,825,304	$173,825,304	$173,825,304	$173,825,304
17	Deemed Equity Portion of Rate Base	$68,476,559	$68,476,559	$69,530,121	$69,530,121	$69,530,121	$69,530,121
18	Income/(Equity Portion of Rate Base)	7.34%	9.00%	8.06%	8.98%	8.06%	8.98%
19	Target Return - Equity on Rate Base	9.00%	9.00%	8.98%	8.98%	8.98%	8.98%
20	Deficiency/Sufficiency in Return on Equity	-1.66%	0.00%	-0.92%	0.00%	-0.92%	0.00%
21	Indicated Rate of Return	5.48%	6.14%	5.78%	6.15%	5.78%	6.15%
22	Requested Rate of Return on Rate Base	6.14%	6.14%	6.15%	6.15%	6.15%	6.15%
23	Deficiency/Sufficiency in Rate of Return	-0.66%	0.00%	-0.37%	0.00%	-0.37%	0.00%
24	Target Return on Equity	$6,162,890	$6,162,890	$6,243,805	$6,243,805	$6,243,805	$6,243,805
25	Revenue Deficiency/(Sufficiency)	$1,134,392	$ -	$639,133	$0	$639,133	$0
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,543,390 (1)		$869,568 (1)		$869,568 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision
1	OM&A Expenses	$18,575,648		$18,210,648		$18,210,648
2	Amortization/Depreciation	$6,703,335		$6,432,205		$6,432,205
3	Property Taxes	$200,710		$200,710		$200,710
5	Income Taxes (Grossed up)	$796,233		$773,309		$773,309
6	Other Expenses	$42,000		$42,000		$42,000
7	Return					
	Deemed Interest Expense	$4,344,498		$4,447,190		$4,447,190
	Return on Deemed Equity	$6,162,890		$6,243,805		$6,243,805
8	**Service Revenue Requirement (before Revenues)**	$36,825,314		$36,349,867		$36,349,867
9	Revenue Offsets	$1,654,991		$2,022,079		$2,022,079
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$35,170,323		$34,327,788		$34,327,788
11	Distribution revenue	$35,170,323		$34,327,788		$34,327,788
12	Other revenue	$1,654,991		$2,022,079		$2,022,079
13	**Total revenue**	$36,825,314		$36,349,867		$36,349,867
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	$ - (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Settlement Agreement	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$36,825,314	$36,349,867	($0)	$36,349,867	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$1,543,390	$869,568	($0)	$869,568	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$35,170,323	$34,327,788	($0)	$34,327,788	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$1,543,390	$869,568	($0)	$869,568	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Settlement Agreement

	Customer Class	**Initial Application**			**Settlement Agreement**			**Per Board Decision**		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual
1	Residential	58,677	466,068,279	-	58,677	461,453,716				
2	GS <50	6,451	195,276,256	-	6,451	193,967,011				
3	GS> 50- 999 kW	801	493,112,062	1,574,312	801	491,288,356	1,568,556			
4	GS> 1,000 - 4,999 kW	30	231,017,192	592,051	30	229,378,990	588,206			
5	Large Use	2	145,503,126	382,038	2	145,141,006	361,276			
6	Street Light	16,260	5,367,464	15,467	16,260	3,798,281	10,945			
7	Sentinel	168	126,989	343	168	126,989	343			
8	Unmetered Scattered Load	499	2,273,988	-	499	2,273,988				
9	Embedded Distributor Hydro One - CND	2	12,605,162	24,387	2	12,605,162	24,387			
10	Embedded Distributor Waterloo North Hydro - CN	1	58,104,381	114,657	1	58,104,381	114,657			
11	Embedded Distributor Hydro One 1 - BCP	1	12,191,720	29,995	1	12,191,720	29,995			
12	Embedded Distributor Brantford Power - BCP	1	347,757	1,075	1	347,757	1,075			
13	Embedded Distributor Hydro One 2 - BCP	4	43,274,122	0	4	43,274,122	102,973			
14										
15										
16										
17										
18										
19										
20										
	Total		**1,665,268,498**	**2,734,324**		**1,653,951,480**	**2,802,414**		**-**	**-**

Notes:

[1] Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Settlement Agreement***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 17,230,358	50.27%	$ 22,646,854	62.30%
2	GS <50	$ 4,015,045	11.71%	$ 4,104,442	11.29%
3	GS> 50- 999 kW	$ 7,645,185	22.30%	$ 5,633,412	15.50%
4	GS> 1,000 - 4,999 kW	$ 2,339,610	6.83%	$ 2,012,723	5.54%
5	Large Use	$ 1,540,113	4.49%	$ 1,108,342	3.05%
6	Street Light	$ 1,085,945	3.17%	$ 494,718	1.36%
7	Sentinel	$ 22,385	0.07%	$ 23,393	0.06%
8	Unmetered Scattered Load	$ 68,563	0.20%	$ 78,300	0.22%
9	Embedded Distributor Hydro One - CND	$ 61,534	0.18%	$ 43,414	0.12%
10	Embedded Distributor Waterloo North H	$ 133,822	0.39%	$ 157,922	0.43%
11	Embedded Distributor Hydro One 1 - BC	$ 121,990	0.36%	$ 30,519	0.08%
12	Embedded Distributor Brantford Power -	$ 13,554	0.04%	$ 12,850	0.04%
13	Embedded Distributor Hydro One 2 - BCP			$ 2,978	0.01%
14					
15					
16					
17					
18					
19					
20					
	Total	$ 34,278,105	100.00%	**$ 36,349,867**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 36,349,867.47**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 17,528,595	$ 17,984,157	$ 19,437,846	$ 1,356,031
2	GS <50	$ 4,131,617	$ 4,238,997	$ 4,238,997	$ 221,287
3	GS> 50- 999 kW	$ 7,466,138	$ 7,660,180	$ 6,518,528	$ 241,566
4	GS> 1,000 - 4,999 kW	$ 2,140,493	$ 2,196,124	$ 2,196,124	$ 89,119
5	Large Use	$ 1,040,061	$ 1,067,091	$ 1,067,091	$ 48,561
6	Street Light	$ 671,811	$ 689,272	$ 537,111	$ 56,550
7	Sentinel	$ 14,573	$ 14,951	$ 20,145	$ 1,334
8	Unmetered Scattered Load	$ 64,042	$ 65,706	$ 67,343	$ 4,551
9	Embedded Distributor Hydro One - CND	$ 50,527	$ 51,840	$ 42,784	$ 630
10	Embedded Distributor Waterloo North H	$ 221,287	$ 227,038	$ 156,258	$ 1,665
11	Embedded Distributor Hydro One 1 - BC	$ 119,034	$ 122,127	$ 30,158	$ 361
12	Embedded Distributor Brantford Power -	$ 5,388	$ 5,528	$ 12,649	$ 200
13	Embedded Distributor Hydro One 2 - BC	$ 4,655	$ 4,776	$ 2,754	$ 224
14					
15					
16					
17					
18					
19					
20					
	Total	$ 33,458,220	$ 34,327,788	$ 34,327,788	$ 2,022,079

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	95.70%	85.40%	91.82%	85 - 115
2	GS <50	102.70%	108.67%	108.67%	80 - 120
3	GS> 50- 999 kW	117.40%	140.27%	120.00%	80 - 120
4	GS> 1,000 - 4,999 kW	102.30%	113.54%	113.54%	80 - 120
5	Large Use	93.90%	100.66%	100.66%	85 - 115
6	Street Light	70.00%	150.76%	120.00%	80 - 120
7	Sentinel	70.00%	69.62%	91.82%	80 - 120
8	Unmetered Scattered Load	117.40%	89.73%	91.82%	80 - 120
9	Embedded Distributor Hydro One - CND	100.00%	120.86%	100.00%	80 - 120
10	Embedded Distributor Waterloo North H	100.00%	144.82%	100.00%	80 - 120
11	Embedded Distributor Hydro One 1 - BC	Not Available	401.35%	100.00%	80 - 120
12	Embedded Distributor Brantford Power -	Not Available	44.58%	100.00%	80 - 120
13	Embedded Distributor Hydro One 2 - BC	Not Available	167.88%	100.00%	80 - 120
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2019	2020	2021	
1	Residential	91.82%	91.82%	91.82%	85 - 115
2	GS <50	108.67%	108.67%	108.67%	80 - 120
3	GS> 50- 999 kW	120.00%	120.00%	120.00%	80 - 120
4	GS> 1,000 - 4,999 kW	113.54%	113.54%	113.54%	80 - 120
5	Large Use	100.66%	100.66%	100.66%	85 - 115
6	Street Light	120.00%	120.00%	120.00%	80 - 120
7	Sentinel	91.82%	91.82%	91.82%	80 - 120
8	Unmetered Scattered Load	91.82%	91.82%	91.82%	80 - 120
9	Embedded Distributor Hydro One - CND	100.00%	100.00%	100.00%	80 - 120
10	Embedded Distributor Waterloo North H	100.00%	100.00%	100.00%	80 - 120
11	Embedded Distributor Hydro One 1 - BC	100.00%	100.00%	100.00%	80 - 120
12	Embedded Distributor Brantford Power -	100.00%	100.00%	100.00%	80 - 120
13	Embedded Distributor Hydro One 2 - BC	100.00%	100.00%	100.00%	80 - 120
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2019 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2020 and 2021 Price Cap IR models, as necessary. For 2020 and 2021, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2018 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	58,677
kWh	461,453,716

Proposed Residential Class Specific Revenue Requirement[1]	$ 19,437,845.97

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 21.81
Distribution Volumetric Rate ($/kWh)	$ 0.0047

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	21.80819867	58,677	$ 15,355,735.85	87.60%
Variable	0.004708725	461,453,716	$ 2,172,858.70	12.40%
TOTAL	-	-	$ 17,528,594.54	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	1

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 17,028,314.93	24.18	$ 17,025,784.59
Variable	$ 2,409,531.04	0.0052	$ 2,399,559.32
TOTAL	$ 19,437,845.97	-	$ 19,425,343.91

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	100.00%	$ 19,437,845.97	$ 27.61	$ 19,440,939.31
Variable	0.00%	$ -	$ -	$ -
TOTAL	-	$ 19,437,845.97	-	$ 19,440,939.31

Checks[3]	
Change in Fixed Rate	$ 3.43
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	$3,093.34
	0.02%

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Settlement Agreement*

Customer and Load Forecast / **Class Allocated Revenues** (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)

	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric
1	Residential	kWh	58,677	461,453,716	-	$ 19,437,846	$ 19,437,846	$ -
2	GS <50	kWh	6,451	193,967,011	-	$ 4,238,997	$ 1,153,007	$ 3,085,990
3	GS> 50- 999 kW	kW	801	491,288,356	1,568,556	$ 6,518,528	$ 949,516	$ 5,569,012
4	GS> 1,000 - 4,999 kW	kW	30	229,378,990	588,206	$ 2,196,124	$ 319,232	$ 1,876,892
5	Large Use	kW	2	145,141,006	361,276	$ 1,067,091	$ 221,025	$ 846,067
6	Street Light	kW	16,260	3,798,281	10,945	$ 537,111	$ 369,970	$ 167,142
7	Sentinel	kW	168	126,989	343	$ 20,145	$ 5,685	$ 14,460
8	Unmetered Scattered Load	kWh	499	2,273,988	-	$ 67,343	$ 34,804	$ 32,539
9	Embedded Distributor Hydro One - CND	kW	2	12,605,162	24,387	$ 42,784	$ -	$ 42,784
10	Embedded Distributor Waterloo North Hydr	kW	1	58,104,381	114,657	$ 156,258	$ -	$ 156,258
11	Embedded Distributor Hydro One 1 - BCP	kW	1	12,191,720	29,995	$ 30,158	$ 689	$ 29,469
12	Embedded Distributor Brantford Power - BC	kW	1	347,757	1,075	$ 12,649	$ -	$ 12,649
13	Embedded Distributor Hydro One 2 - BCP	kW	4	43,274,122	102,973	$ 2,754	$ 2,754	$ -
14			-	-	-			
15			-	-	-			
16			-	-	-			
17			-	-	-			
18			-	-	-			
19			-	-	-			
20			-	-	-			

Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1) / **Distribution Rates** / **Revenue Reconciliation**

	Customer Class	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate		Volumetric Rate No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	100.00%	0.00%		$27.61	2	$0.0000	/kWh	4	$ 19,440,939.31	$ -	$ 19,440,939.31
2	GS <50	27.20%	72.80%		$14.89		$0.0159	/kWh		$ 1,152,629.03	$ 3,084,075.4797	$ 4,236,704.51
3	GS> 50- 999 kW	14.57%	85.43%	$ 163,077	$98.74		$3.6544	/kW		$ 949,562.13	$ 5,732,131.1144	$ 6,518,616.74
4	GS> 1,000 - 4,999 kW	14.54%	85.46%	$ 348,498	$886.87		$3.7834	/kW		$ 319,231.78	$ 2,225,418.7121	$ 2,196,152.00
5	Large Use	20.71%	79.29%		$9,209.36		$2.3419	/kW		$ 221,024.64	$ 846,072.9920	$ 1,067,097.63
6	Street Light	68.88%	31.12%		$1.90		$15.2704	/kW		$ 370,717.99	$ 167,141.6027	$ 537,859.59
7	Sentinel	28.22%	71.78%		$2.82		$42.1667	/kW		$ 5,685.12	$ 14,459.8048	$ 20,144.92
8	Unmetered Scattered Load	51.68%	48.32%		$5.81		$0.0143	/kWh		$ 34,790.28	$ 32,518.0284	$ 67,308.31
9	Embedded Distributor Hydro One - CND	0.00%	100.00%		$0.00		$1.7543	/kW		$ -	$ 42,782.8783	$ 42,782.88
10	Embedded Distributor Waterloo North Hydr	0.00%	100.00%		$0.00		$1.3628	/kW		$ -	$ 156,254.4020	$ 156,254.40
11	Embedded Distributor Hydro One 1 - BCP	2.28%	97.72%		$57.39		$0.9825	/kW		$ 688.68	$ 29,469.6997	$ 30,158.38
12	Embedded Distributor Brantford Power - BC	0.00%	100.00%		$0.00		$11.7671	/kW		$ -	$ 12,649.1618	$ 12,649.16
13	Embedded Distributor Hydro One 2 - BCP	100.00%	0.00%		$57.39		$0.0000	/kW		$ 2,754.72	$ -	$ 2,754.72
14										$ -	$ -	$ -
15										$ -	$ -	$ -
16										$ -	$ -	$ -
17										$ -	$ -	$ -
18										$ -	$ -	$ -
19										$ -	$ -	$ -
20										$ -	$ -	$ -

Total Transformer Ownership Allowance $ 511,575

Total Distribution Revenues	$34,329,422.55
Base Revenue Requirement	$34,327,788.47
Difference	$ 1,634.08
% Difference	0.005%

Rates recover revenue requirement

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calculated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2019 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 10,507,388	6.14%	$ 171,191,397	$ 176,009,945	$ 13,200,746	$ 6,703,335	$ 796,233	$ 18,575,648	$ 36,825,314	$ 1,654,991	$ 35,170,323	$ 1,543,390
1	Update for 2017 actuals	Costs, CDM results and peak load for LDG customer	$ 10,776,272	6.14%	$ 175,572,184	$ 222,967,772	$ 16,722,583	$ 6,460,652	$ 732,168	$ 18,575,648	$ 36,787,451	$ 1,641,556	$ 35,145,895	$ 1,687,675
		Change	$ 268,884	0.00%	$ 4,380,787	$ 46,957,826	$ 3,521,837	-$ 242,683	-$ 64,065	$ -	-$ 37,863	-$ 13,435	-$ 24,428	$ 144,285
2	3-Staff-56	Pole rental impact	$ 10,776,272	6.14%	$ 175,572,184	$ 222,967,772	$ 16,722,583	$ 6,460,652	$ 732,168	$ 18,575,648	$ 36,787,451	$ 1,870,459	$ 34,916,992	$ 1,458,772
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 228,903	-$ 228,903	-$ 228,903
3	1-Staff-15 f)	Remove BPI Shared Services	$ 10,641,468	6.14%	$ 173,375,892	$ 222,772,772	$ 16,707,958	$ 6,423,985	$ 753,897	$ 18,380,648	$ 36,442,709	$ 1,870,459	$ 34,572,250	$ 1,114,029
		Change	-$ 134,804	0.00%	-$ 2,196,292	-$ 195,000	-$ 14,625	-$ 36,667	$ 21,729	-$ 195,000	-$ 344,742	$ -	-$ 344,742	-$ 344,742
4		Settlement Proposal	$ 10,690,995	6.15%	$ 173,825,304	$ 222,602,772	$ 16,695,208	$ 6,432,205	$ 773,309	$ 18,210,648	$ 36,349,867	$ 2,022,079	$ 34,327,788	$ 869,568
		Change	$ 49,527	0.01%	$ 449,412	-$ 170,000	-$ 12,750	$ 8,220	$ 19,412	-$ 170,000	-$ 92,842	$ 151,620	-$ 244,462	-$ 244,461
5														

APPENDIX B

UPDATED APPENDIX 2-AB: CAPITAL EXPENDITURE SUMMARY

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements
Consolidated Former CND and BCP (2014-2015) and Energy+ Inc. (2016-2023)

First year of Forecast Period: *2019*

CATEGORY	**Historical Period** (previous plan[1] & actual)															**Forecast Period** (planned)				
	2014			2015			2016			2017			2018			2019	2020	2021	2022	2023
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Forecast	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	9,038	3,781	(58.2%)	11,749	8,064	(31.4%)	4,355	5,486	26.0%	4,867	5,599	15.0%	5,423	7,588	39.9%	7,069	4,007	4,352	3,934	4,129
System Renewal	5,921	4,361	(26.3%)	5,925	6,069	2.4%	6,700	8,193	22.3%	9,064	9,470	4.5%	5,819	6,148	5.7%	5,206	8,591	8,007	8,849	8,672
System Service	862	581	(32.6%)	745	1,399	87.8%	840	718	(14.5%)	1,984	87	(95.6%)	2,531	704	(72.2%)	127	591	954	422	422
General Plant	4,306	3,037	(29.5%)	2,476	2,337	(5.6%)	2,182	1,786	(18.1%)	3,016	2,413	(20.0%)	1,880	1,527	(18.8%)	943	5,556	1,668	9,638	1,765
Deferred Revenue (Capital Contributions)	(2,436)	(756)	(69.0%)	(4,082)	(4,496)	10.1%	(1,279)	(2,763)	116.0%	(1,429)	(3,212)	124.8%	(2,133)	(3,778)	77.1%	(1,966)	(769)	(886)	(772)	(782)
TOTAL EXPENDITURE	17,691	11,004	(37.8%)	16,813	13,373	(20.5%)	12,798	13,420	4.9%	17,502	14,357	(18.0%)	13,520	12,189	(9.8%)	11,379	17,976	14,095	22,071	14,206
System O&M	$ 5,805	$ 5,857	0.9%	$ 6,136	$ 5,636	(8.1%)	5,721	5,606	(2.0%)	$ 5,661	$ 5,747	1.5%	$ 5,915	$ 5,915	0.0%	$ 5,931	$ 5,976	$ 6,022	$ 6,069	$ 6,116
Total Net Expenditures		$ 11,004			$ 13,373			$ 13,420			$ 14,357			$ 12,189		$ 11,379				
Change in Work in Progress		(806)			(2,156)			(72)			1,284			-		-				
Assets Not In Use														(128)						
Asset Transfer on FA Continuity Schedule - Not an Addition		631																		
Total Net Expenditures, as per Fixed Asset Continuity Schedules		10,829			11,217			13,348			15,641			12,061		11,379				

APPENDIX C

UPDATED APPENDIX 2-BA: 2018 & 2019 FIXED ASSET CONTINUITY SCHEDULES

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard: MIFRS
Year: 2018

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 4,906,380	$ 315,358	$ -	$ 5,221,738	$ (2,950,984)	$ (703,947)	$ -	$ (3,654,931)	$ 1,566,807
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 347,843	$ -	$ -	$ 347,843	$ -	$ -	$ -	$ -	$ 347,843
47	1808	Buildings	$ 1,451,373	$ -	$ -	$ 1,451,373	$ (132,454)	$ (32,798)	$ -	$ (165,252)	$ 1,286,121
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 9,434,192	$ 35,000	$ -	$ 9,469,192	$ (1,632,523)	$ (270,136)	$ -	$ (1,902,659)	$ 7,566,533
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 35,205,590	$ 3,819,096	$ (250,000)	$ 38,774,686	$ (1,482,979)	$ (855,540)	$ 175,000	$ (2,163,519)	$ 36,611,167
47	1835	Overhead Conductors & Devices	$ 36,799,611	$ 4,395,213	$ -	$ 41,194,824	$ (2,929,443)	$ (1,046,324)	$ -	$ (3,975,767)	$ 37,219,057
47	1840	Underground Conduit	$ 21,077,556	$ 1,562,020	$ -	$ 22,639,576	$ (965,475)	$ (301,972)	$ -	$ (1,267,447)	$ 21,372,129
47	1845	Underground Conductors & Devices	$ 30,744,742	$ 2,201,884	$ -	$ 32,946,626	$ (2,433,073)	$ (725,197)	$ -	$ (3,158,270)	$ 29,788,355
47	1850	Line Transformers	$ 33,301,784	$ 2,297,895	$ (450,000)	$ 35,149,679	$ (764,508)	$ (863,698)	$ 315,000	$ (1,313,206)	$ 33,836,473
47	1855	Services (Overhead & Underground)	$ 1,547,792	$ -	$ -	$ 1,547,792	$ (151,960)	$ (42,514)	$ -	$ (194,474)	$ 1,353,319
47	1860	Meters	$ 10,256,363	$ 774,242	$ (300,000)	$ 10,730,605	$ (3,373,075)	$ (789,744)	$ 210,000	$ (3,952,818)	$ 6,777,787
N/A	1905	Land	$ 301,423	$ -	$ (87,795)	$ 213,628	$ -	$ -	$ -	$ -	$ 213,628
47	1908	Buildings & Fixtures	$ 2,670,200	$ 14,500	$ (544,100)	$ 2,140,600	$ (731,007)	$ (132,838)	$ 273,198	$ (590,647)	$ 1,549,953
13	1910	Leasehold Improvements	$ 24,525	$ -	$ -	$ 24,525	$ (24,525)	$ -	$ -	$ (24,525)	$ -
8	1915	Office Furniture & Equipment	$ 529,195	$ 9,200	$ -	$ 538,395	$ (212,231)	$ (58,393)	$ -	$ (270,624)	$ 267,770
45.1	1920	Computer Equip.-Hardware	$ 1,926,509	$ 205,200	$ -	$ 2,131,709	$ (1,593,866)	$ (216,453)	$ -	$ (1,810,318)	$ 321,391
10	1930	Transportation Equipment	$ 3,523,708	$ 100,000	$ -	$ 3,623,708	$ (620,686)	$ (455,861)	$ -	$ (1,076,547)	$ 2,547,161
8	1935	Stores Equipment	$ 15,399	$ -	$ -	$ 15,399	$ (4,431)	$ (1,463)	$ -	$ (5,894)	$ 9,505
8	1940	Tools, Shop & Garage Equipment	$ 679,589	$ 108,500	$ -	$ 788,089	$ (217,812)	$ (100,598)	$ -	$ (318,410)	$ 469,679
8	1945	Measurement & Testing Equipment	$ 11,161	$ -	$ -	$ 11,161	$ (11,161)	$ -	$ -	$ (11,161)	-$ 0
8	1950	Power Operated Equipment	$ 12,750	$ -	$ -	$ 12,750	$ (8,936)	$ (2,549)	$ -	$ (11,485)	$ 1,265
8	1955	Communications Equipment	$ 512	$ -	$ -	$ 512	$ (571)	$ -	$ -	$ (571)	-$ 59
8	1960	Miscellaneous Equipment	$ 304,897	$ -	$ -	$ 304,897	$ (299,557)	$ (501)	$ -	$ (300,058)	$ 4,839
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 17,689	$ -	$ -	$ 17,689	$ (590)	$ (1,179)	$ -	-$ 1,769	$ 15,920
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ (16,106,934)	$ -	$ -	$ (16,106,934)	$ 1,787,513	$ 412,556	$ -	$ 2,200,069	$ (13,906,865)
	2005	Property Under Finance Leases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	2010	Electric Plant Purchased or Sold	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ (11,291,534)	$ (3,778,000)	$ -	$ (15,069,534)	$ 417,543	$ 209,459	$ -	$ 627,002	$ (14,442,532)
		Sub-Total	**$ 167,692,316**	**$ 12,060,108**	**$ (1,631,895)**	**$ 178,120,529**	**$ (18,336,791)**	**$ (5,979,689)**	**$ 973,198**	**$ (23,343,281)**	**$ 154,777,247**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 167,692,316**	**$ 12,060,108**	**$ (1,631,895)**	**$ 178,120,529**	**$ (18,336,791)**	**$ (5,979,689)**	**$ 973,198**	**$ (23,343,281)**	**$ 154,777,247**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ (5,979,689)**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ (455,861)
Stores Equipment	
Removal Costs	$ 316,160
Deferred Revenue incl. in Other Revenue	$ 209,459
Net Depreciation	$ 6,049,447

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	MIFRS
Year	2019

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 5,221,738	$ 526,500	$ -	$ 5,748,238	$ (3,654,931)	$ (721,713)	$ -	$ (4,376,644)	$ 1,371,594
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 347,843	$ -	$ -	$ 347,843	$ -	$ -	$ -	$ -	$ 347,843
47	1808	Buildings	$ 1,451,373	$ -	$ -	$ 1,451,373	$ (165,252)	$ (32,798)	$ -	$ (198,050)	$ 1,253,323
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 9,469,192	$ 55,000	$ -	$ 9,524,192	$ (1,902,659)	$ (271,209)	$ -	$ (2,173,868)	$ 7,350,324
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 38,774,686	$ 2,599,799	$ (250,000)	$ 41,124,485	$ (2,163,519)	$ (933,254)	$ 175,000	$ (2,921,773)	$ 38,202,711
47	1835	Overhead Conductors & Devices	$ 41,194,824	$ 3,034,274	$ -	$ 44,229,098	$ (3,975,767)	$ (1,147,917)	$ -	$ (5,123,684)	$ 39,105,414
47	1840	Underground Conduit	$ 22,639,576	$ 1,567,624	$ -	$ 24,207,200	$ (1,267,447)	$ (322,041)	$ -	$ (1,589,487)	$ 22,617,713
47	1845	Underground Conductors & Devices	$ 32,946,626	$ 2,208,046	$ -	$ 35,154,672	$ (3,158,270)	$ (776,436)	$ -	$ (3,934,706)	$ 31,219,966
47	1850	Line Transformers	$ 35,149,679	$ 2,186,091	$ (450,000)	$ 36,885,770	$ (1,313,206)	$ (914,169)	$ 315,000	$ (1,912,375)	$ 34,973,396
47	1855	Services (Overhead & Underground)	$ 1,547,792	$ -	$ -	$ 1,547,792	$ (194,474)	$ (42,514)	$ -	$ (236,988)	$ 1,310,805
47	1860	Meters	$ 10,730,605	$ 751,092	$ (1,730,782)	$ 9,750,915	$ (3,952,818)	$ (831,086)	$ 1,537,309	$ (3,246,595)	$ 6,504,320
N/A	1905	Land	$ 213,628	$ -	$ -	$ 213,628	$ -	$ -	$ -	$ -	$ 213,628
47	1908	Buildings & Fixtures	$ 2,140,600		$ -	$ 2,140,600	$ (590,647)	$ (126,697)	$ -	$ (717,344)	$ 1,423,256
13	1910	Leasehold Improvements	$ 24,525	$ -	$ -	$ 24,525	$ (24,525)	$ -	$ -	$ (24,525)	$ -
8	1915	Office Furniture & Equipment	$ 538,395	$ 3,600	$ -	$ 541,995	$ (270,624)	$ (55,735)	$ -	$ (326,359)	$ 215,635
45.1	1920	Computer Equip.-Hardware	$ 2,131,709	$ 240,700	$ -	$ 2,372,409	$ (1,810,318)	$ (219,512)	$ -	$ (2,029,830)	$ 342,579
10	1930	Transportation Equipment	$ 3,623,708	$ 105,000	$ -	$ 3,728,708	$ (1,076,547)	$ (458,181)	$ -	$ (1,534,728)	$ 2,193,980
8	1935	Stores Equipment	$ 15,399		$ -	$ 15,399	$ (5,894)	$ (1,463)	$ -	$ (7,357)	$ 8,042
8	1940	Tools, Shop & Garage Equipment	$ 788,089	$ 66,700	$ -	$ 854,789	$ (318,410)	$ (96,673)	$ -	$ (415,083)	$ 439,706
8	1945	Measurement & Testing Equipment	$ 11,161	$ -	$ -	$ 11,161	$ (11,161)	$ -	$ -	$ (11,161)	-$ 0
8	1950	Power Operated Equipment	$ 12,750	$ -	$ -	$ 12,750	$ (11,485)	$ (1,264)	$ -	$ (12,749)	$ 1
8	1955	Communications Equipment	$ 512	$ -	$ -	$ 512	$ (571)	$ -	$ -	$ (571)	-$ 59
8	1960	Miscellaneous Equipment	$ 304,897	$ -	$ -	$ 304,897	$ (300,058)	$ (501)	$ -	$ (300,559)	$ 4,338
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 17,689	$ -	$ -	$ 17,689	$ (1,769)	$ (1,179)	$ -	-$ 2,948	$ 14,741
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ (16,106,934)	$ -	$ -	$ (16,106,934)	$ 2,200,069	$ 412,556	$ -	$ 2,612,625	$ (13,494,309)
	2005	Property Under Finance Leases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	2010	Electric Plant Purchased or Sold	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue [5]	$ (15,069,534)	$ (1,966,150)	$ -	$ (17,035,684)	$ 627,002	$ 272,683	$ -	$ 899,685	$ (16,135,999)
		Sub-Total	**$ 178,120,529**	**$ 11,378,277**	**$ (2,430,782)**	**$ 187,068,024**	**$ (23,343,281)**	**$ (6,269,103)**	**$ 2,027,309**	**$ (27,585,075)**	**$ 159,482,949**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 178,120,529**	**$ 11,378,277**	**$ (2,430,782)**	**$ 187,068,024**	**$ (23,343,281)**	**$ (6,269,103)**	**$ 2,027,309**	**$ (27,585,075)**	**$ 159,482,949**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**$ (6,269,103)**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	$ (458,181)
Stores Equipment	$ -
Removal Costs	$ 348,600
Deferred Revenue incl. in Other Revenue	$ 272,683
Net Depreciation	$ 6,432,205

APPENDIX D

UPDATED 2018 AND 2019 CAPITAL PLAN

During the settlement conference, Energy+ was asked to provide an update on actual 2018 capital expenditures year-to-date with an updated forecast for 2018 and 2019. Energy+ provided the update noted below, which shows the impact of this update on both the 2018 and 2019 capital plans.

2019 Update Capital Expenditures

	2019 Plan - DSP (IR Updated)	2019 Update	Variance
System Access	$ 4,524,207	$ 7,068,507	$ 2,544,300
System Renewal	$ 6,652,700	$ 5,506,400	$ (1,146,300)
System Service	$ 367,000	$ 127,000	$ (240,000)
General Plant	$ 943,000	$ 943,000	$ -
	$ 12,486,907	$ 13,644,907	$ 1,158,000
Deffered Revenue (Capital Contributions)	$ (817,480)	$ (1,966,630)	$ (1,149,150)
	$ 11,669,427	**$ 11,678,277**	**$ 8,850**

	2018 Plan - DSP	2018 Update	Variance
System Access	$ 5,423,015	$ 7,588,226	$ 2,165,211
System Renewal	$ 5,818,700	$ 6,147,534	$ 328,834
System Service	$ 2,531,100	$ 703,837	$ (1,827,263)
General Plant	$ 1,880,342	$ 1,527,000	$ (353,342)
	$ 15,653,157	$ 15,966,597	$ 313,440
Deffered Revenue (Capital Contributions)	$ (2,132,910)	$ (3,778,000)	$ (1,645,090)
	$ 13,520,247	**$ 12,188,597**	**$ (1,331,650)**

APPENDIX E

ENERGY+ RESPONSES TO CLARIFICATION QUESTIONS

See attached.

APPENDIX F

Final Issues List

1. PLANNING

1.1 Capital

Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

- customer feedback and preferences
- productivity
- benchmarking of costs
- reliability and service quality
- impact on distribution rates
- trade-offs with OM&A spending
- government-mandated obligations
- the objectives of the Applicant and its customers
- the distribution system plan, and
- the business plan.

1.2 OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to:

- customer feedback and preferences
- productivity
- benchmarking of costs
- reliability and service quality
- impact on distribution rates
- trade-offs with capital spending
- government-mandated obligations
- the objectives of the Applicant and its customers
- the distribution system plan, and

- the business plan.

2. REVENUE REQUIREMENT

2.1 Are all elements of the Revenue Requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?

2.2 Has the Revenue Requirement been accurately determined based on these elements?

3. LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

3.1 Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the number and energy and demand requirements of the applicant's customers?

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

3.3 Are the applicant's proposals for rate design appropriate, including the proposal for distribution rate harmonization?

3.4 Has the applicant appropriately applied the OEB's policy on residential rate design?

3.5 Are the proposed Retail Transmission Service Rates and LV Rates appropriate?

3.6 Is the proposal for using gross load billing for Retail Transmission Rates for customers who have load displacement generation appropriate?

3.7 Is the proposal for implementing a standby charge for the Large Use, GS 1,000 to 4,999 kW and GS 50 to 999 kW customer classes with load displacement appropriate?

4. ACCOUNTING

4.1 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?

4.2 Are the applicant's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, and the continuation of existing accounts appropriate?

5. OTHER

5.1 Is the proposed effective date (i.e. January 1, 2019) for 2019 rates appropriate?

APPENDIX E

Exhibit 2 – Rate Base

OEB Staff - Settlement Proposal - Clarification Question 1

Ref: 2-Staff-12, 2-Staff-15, 1-Staff-10

a) Please specify the changes Energy+ made to App.2-AB, Capital Expenditures, following the proposed changes of in-service date for each of the Southworks facility, Garden Avenue facilities and Bishop St. renovation:[1]

   i. For 2019 test year and 2020 related to Garden Avenue Facility.
   ii. For 2020, 2021 (if applicable) and 2022 related to Southworks Facility.
   iii. For 2022 related to Bishop St. renovation.

RESPONSE

The table below provides a summary of the changes made to the General Plant category by Energy+ to Appendix 2-AB Capital Expenditures for the 2019 test year, and 2020, and 2022 for the proposed changes to the in-service dates for the Southworks facility, Garden Avenue facilities and the Bishop St. renovations:

$000's

Changes Made to General Plant:	**2019**	**2020**	**2021**	**2022**	**2023**
Move Shared Facilities with BPI expenditures to 2020 Move **Southworks** expenditures to 2022 Remove Bishop St. renovations from the five year forecast	(4,400)	4,400 (5,000)		5,000 (2,000)	
	(4,400)	(600)	-	3,000	-

Energy+ notes that there was an error in the amount reported in the 2020 year in the Appendix 2-AB filed with the IR Responses. The general plant amount in 2020 was incorrectly reported as $5,656, however, the amount should have been $5,556.

Please refer to response to follow up Question #1 with respect to the revised estimate for the Southworks facility of $8.1MM.

[1] 2-Staff-12 f and 2-staff-15 f

Energy+ has provided a revised Appendix 2AB Capital Expenditures attached to this question as Appendix 2-1.

The following is a reconciliation of the Appendix 2AB as filed compared to the Appendix 2AB as amended and included in this response.

CATEGORY	As Revised - Appendix 2B - Follow Up Questions Forecast Period (planned) 2019	2020	2021	2022	2023	As Filed - Chapter 2 Appendices Schedule 2AB Forecast Period (planned) 2019	2020	2021	2022	2023	Changes through IR Process 2019	2020	2021	2022	2023
			$ '000					$ '000							
System Access	4,524	4,007	4,352	3,934	4,129	4,524	4,007	4,352	3,934	4,129	-	-	-	-	-
System Renewal	6,653	8,591	8,007	8,849	8,672	6,653	8,591	8,007	8,849	8,672	-	-	-	-	-
System Service	367	591	954	422	422	367	591	954	422	422	-	-	-	-	-
General Plant	943	5,556	1,668	6,538	1,765	5,343	6,156	1,668	3,538	1,765	(4,400)	(600)	-	3,000	-
Deferred Revenue (Capital Contributions)	(817)	(769)	(886)	(772)	(782)	(817)	(769)	(886)	(772)	(782)	-	-	-	-	-
TOTAL EXPENDITURE	11,670	17,976	14,095	18,971	14,206	16,070	18,576	14,095	15,971	14,206	(4,400)	(600)	-	3,000	-
System O&M	$ 5,931	$ 5,976	$ 6,022	$ 6,069	$ 6,116	$ 5,931	$ 5,976	$ 6,022	$ 6,069	$ 6,116	-	-	-	-	-

OEB Staff - Settlement Proposal - Clarification Question 1

b) Please discuss why there is no change made to the System O&M in App.2-AB after changing the in-service dates of proposed facilities.

RESPONSE

Energy+ did not make any changes to the System O&M in Appendix 2-AB Capital Expenditures after changing the in-service dates of the proposed facilities. The lease costs for the shared facilities were originally included in Office and Building costs, which were included in the Administrative portion of OM&A. The removal of these costs reduced the Administrative expenditures in Appendix 2JA, Appendix 2JB, and Appendix 2JC, however, this change would not have resulted in a change to Appendix 2-AB System O&M.

OEB Staff - Settlement Proposal - Clarification Question 1

c) Please specify the reduction of depreciation expense for 2019 test year related to the removal of Garden Avenue facility.

RESPONSE

The impact of removing the $4,400,000 in capital costs related to the Garden Avenue facility in the 2019 Test Year was a reduction in depreciation expense of $36,667. Energy+ used a 60 year life for amortization and applied the $^1/_2$ year rule in the 2019 Test Year.

OEB Staff - Settlement Proposal - Clarification Question 1

d) Please specify the change in depreciation expense for 2019 test year related to updating 2017 amounts to actuals.

RESPONSE

As provided in the 2019 EnergyPlus_Rev_Reqt_Workform_1 Staff 2.xlsm file, at Tab 14 Tracking Sheet, Reference 1 Update for 2017 Actuals, the depreciation expense for the 2019 Test Year was reduced by $242,683 as a result of updating the 2017 fixed assets to actuals.

OEB Staff - Settlement Proposal - Clarification Question 1

e) Please clarify whether or not Energy+ has updated App. 2-BA Fixed Asset Continuity Schedule for 2018 bridge year using 2018 year to date actuals.

RESPONSE

Energy+ did not update Appendix 2-BA Fixed Asset Continuity Schedule for the 2018 bridge year using 2018 year-to-date actuals. The 2018 Bridge Year Appendix 2-BA Fixed Asset Continuity Schedule was updated to reflect the following changes:

- Updated the Opening Costs and Opening Accumulated Depreciation as a result of updating the 2017 Actuals.
- Updated the 2018 depreciation expense to reflect changes to the 2018 depreciation expense as a result of updating the 2017 Actuals (i.e. depreciation changes to reflect the differences in additions in 2017 based on Actuals).

The additions and disposals for the 2018 Bridge Year were not revised using year-to-date actuals as the 2018 fixed asset continuity schedule is intended to reflect the expected additions and disposals for a full year, not a partial year.

OEB Staff - Settlement Proposal - Clarification Question 1

f) Please explain why capital expenditure on system service for 2017 was 95.6% (App.2-AB) lower than the plan.

RESPONSE

Actual System Service expenditures for 2017 were $87,000, compared to the Plan of $1,984,000. As explained in Exhibit 2, Page 69 of 1497, the variance in System Service expenditures for 2017 compared to plan was principally explained by the deferral of the investment in land and engineering studies for a new transformer station (MTS#2) which was deferred and planned for 2018.

APPENDIX 2-1 - AMENDED APPENDIX 2AB – CAPITAL EXPENDITURES

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

Consolidated Former CND and BCP (2014-2015) and Energy+ Inc. (2016-2023)

First year of Forecast Period: *2019*

CATEGORY	Historical Period (previous plan[1] & actual) 2014 Plan	2014 Actual	2014 Var	2015 Plan	2015 Actual	2015 Var	2016 Plan	2016 Actual	2016 Var	2017 Plan	2017 Actual	2017 Var	2018 Plan	2018 Forecast	2018 Var	Forecast Period (planned) 2019	2020	2021	2022	2023
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	9,038	3,781	(58.2%)	11,749	8,064	(31.4%)	4,355	5,486	26.0%	4,867	5,599	15.0%	5,423	5,423	0.0%	4,524	4,007	4,352	3,934	4,129
System Renewal	5,921	4,361	(26.3%)	5,925	6,069	2.4%	6,700	8,193	22.3%	9,064	9,470	4.5%	5,819	5,819	0.0%	6,653	8,591	8,007	8,849	8,672
System Service	862	581	(32.6%)	745	1,399	87.8%	840	718	(14.5%)	1,984	87	(95.6%)	2,531	2,531	0.0%	367	591	954	422	422
General Plant	4,306	3,037	(29.5%)	2,476	2,337	(5.6%)	2,182	1,786	(18.1%)	3,016	2,413	(20.0%)	1,880	1,880	0.0%	943	5,556	1,668	6,538	1,765
Deferred Revenue (Capital Contributions)	(2,436)	(756)	(69.0%)	(4,082)	(4,496)	10.1%	(1,279)	(2,763)	116.0%	(1,429)	(3,212)	124.8%	(2,133)	(2,133)	0.0%	(817)	(769)	(886)	(772)	(782)
TOTAL EXPENDITURE	17,691	11,004	(37.8%)	16,813	13,373	(20.5%)	12,798	13,420	4.9%	17,502	14,357	(18.0%)	13,520	13,520	0.0%	11,670	17,976	14,095	18,971	14,206
System O&M	$ 5,805	$ 5,857	0.9%	$ 6,136	$ 5,636	(8.1%)	5,721	5,606	(2.0%)	$ 5,661	$ 5,747	1.5%	$ 5,915	$ 5,915	0.0%	$ 5,931	$ 5,976	$ 6,022	$ 6,069	$ 6,116
Total Net Expenditures		$ 11,004			$ 13,373			$ 13,420			$ 14,357			$ 13,520		$ 11,670				
Change in Work in Progress		(806)			(2,156)			(72)			1,284			-		-				
Assets Not In Use														(2,026)						
Asset Transfer on FA Continuity Schedule - Not an Addition		631																		
Total Net Expenditures, as per Fixed Asset Continuity Schedules		10,829			11,217			13,348			15,641			11,494		11,670				

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year 12

OEB Staff - Settlement Proposal - Clarification Question 2

Ref: 3-Staff-54; Exhibit 3, page 6

Energy+ stated that “The new load displacement generation has been taken out of the load forecast since the loss of distribution revenue associated with the new load displacement generation will be collected with the proposed standby charge”. OEB staff notes that the same adjustment has been made to the LRAMVA target.

Energy+ stated that “This program is associated with savings from new load displacement generation anticipated in 2018.” In reference to the regression model, Energy+ also stated that “the variable named Co-generation Facility Flag has been 13 added to reflect the impact of new co-generation facilities added in 2016.”

a) Please confirm that Energy+ will not seek to recover through an LRAMVA rate rider any future IESO verified savings for which a standby charge could be applied.

b) Please confirm that the “new load displacement generation anticipated in 2018” is actually savings which have already been occurring since 2016 at the co-generation facility added in that year. Otherwise, please explain and differentiate the projects:

RESPONSE

a) Energy+ confirms it will not seek to recover through an LRAMVA rate rider any future IESO verified savings for which a standby charge could be applied.

b) The “new load displacement generation anticipated in 2018” are additional load displacement generation projects that are anticipated to start in 2018 as part of the 2018 Process and Systems Upgrades Program outlined in the current Energy+ 2015 to 2020 CDM plan.

OEB Staff - Settlement Proposal - Clarification Question 3

Ref: Response to 9-Staff-96

a) Please confirm that the DVA balances and transactions for 2017 were actually compiled by service territory and not on a consolidated basis.

RESPONSE

Energy+ confirms that the DVA balances and transactions for 2017 were compiled by service territory and then consolidated.

OEB Staff - Settlement Proposal - Clarification Question 3

Ref: Response to 9-Staff-96

b) Please confirm that the IESO invoice has yet to be harmonized, and had not been harmonized when the 2017 balances were compiled.

RESPONSE

Energy+ confirms that the IESO invoice has not been harmonized, and was not harmonized when the 2017 balances were complied.

OEB Staff - Settlement Proposal - Clarification Question 4

Ref: Response to 9-Staff-97

a) Please confirm that the Applicant settles with the IESO on the 4th day of the following month (i.e. December consumption is settled on January 4th and so on), and not on a one month lag (i.e. December consumption is settled on February 4th and so on).

RESPONSE

Energy+ confirms that it settles with the IESO on the 4th day of the following month, and not on a one month lag.

OEB Staff - Settlement Proposal - Clarification Question 4

Ref: Response to 9-Staff-97

b) The Applicant completed its responses to Appendix A of the GA Analysis Workform Instructions. Based on the responses provided, please confirm the following (since the responses are the same for both service territories, OEB staff will assume that the responses provided relate to both service territories, if different, please indicate):

i. In the response provided for 2a, please confirm that the Applicant is indicating that its monthly RPP settlement with the IESO is based on actual consumption for the month being settled. Please also confirm that the Applicant's systems have the capability to produce such consumption data, including consumption that is yet to be billed for the month being settled, by the 4th day of the following month. Please further confirm that the only estimate that is used in the Applicant's monthly RPP IESO settlement is the GA rate (2nd estimate).

ii. In the response provided to 2f), please explain why the CT1142 true-up adjustment impacts both accounts 1588 and 1589 when CT 1142 is only recorded to account 1588 (as indicated in the Applicant's response to Question 1 of Appendix A).

iii. In the response provided to Question 3a, please confirm that the Applicant waits for the actual CT 148 invoice to come in before it books anything to its G/L. and that no estimate of the GA charge is initially recorded for which a true-up is then recorded once the actual invoice comes in.

iv. In the response to 3d, the Applicant has indicated that no true-up related to the recording of CT 148 is required because the invoice is split based on actual consumption at the time the invoice is received. However in response e) the Applicant has indicated that the month of December 2017 was trued up in 2018, please explain what true-up is being referred to here.

v. What is being trued up in g) if the split was already done based on actual? Please explain, as noted above.

vi. In the response to question 4, the applicant provided a summary of the reversal required in the 2017 DVA continuity schedule related to principal adjustments that were recorded in 2015 and 2016

1. For Brant County, as part of the last IRM application the applicant recorded principal adjustments to accounts 1588 and 1589 as follows

	1588	**1589**
2015	$607,478	($607,478)
2016	($333,169)	$333,169
Total	$274,309	($274,309

Note that the $1,133,153 that was recorded as a principal adjustment to account 1589 in 2015 is ignored for purposes of this analysis and it was recorded in order to reverse out the impact of the principal adjustment that was recorded for 2014.

Please provide the period in which each of the above principal adjustments were actually recorded in the utility's G/L and please provide further rationale as to why the Applicant believes that they do not need to be reversed in the 2017 DVA continuity schedule and GA Analysis Wokform.

2. For the CND service territory, the Applicant had recorded the following principal adjustments for 2015 and 2016:

Account 1588:

DVA Continuity Schedule Adjustment (COP 1589) - Energy+ (CND)	EB-2017-0030 (IRM Application)		
	2015	2016	Total
Adjust unbilled to actual revenue differences	$ 13,986		$ 13,986
RPP/Non-RPP Allocation Adjustment (GL Entry)	$ 2,675,144	$ 636,201	$ 3,311,345
Total Adjustments Reported in DVA Continuity Schedule	**$ 2,689,130**	**$ 636,201**	**$ 3,325,331**

Account 1589:

DVA Continuity Schedule Adjustment (GA 1589) - Energy+ (CND)	EB-2017-0030 (IRM Application)		
	2015	2016	Total
Remove prior year end unbilled to actual revenue differences		(14,906)	(14,906)
Add current year end unbilled to actual revenue differences	209,336		209,336
IESO Overbilling - Class A timing differences	754,002	(158,185)	595,817
	$ 963,338	**$ (173,091)**	**$ 790,246**
RPP/Non-RPP Allocation Adjustment (GL Entry)	(2,675,144)	(636,201)	(3,311,345)
Total Adjustments Reported in DVA Continuity Schedule	**$ (1,711,806)**	**$ (809,292)**	**$ (2,521,098)**

It is not clear why the Applicant has excluded the adjustments for $2,675K and $636K from the principal adjustment reversals that it has proposed in the 2017 continuity schedule. Please explain rationale for excluding them and please provide the period in which the Applicant actually recorded these amounts to their G/L?

RESPONSE

i. Energy+'s monthly RPP settlement with the IESO is based on actual consumption for the most recent billing period. Energy+'s systems do not have the capability to produce consumption data that is yet to be billed for the month being settled. Energy+ does not bill RPP customers on a calendar month basis. This creates a lag in the settlement process for the unbilled portion of consumption during the month.

In order for Energy+ to settle and report on the actual GA rate, Energy+ takes the billed consumption from the meter read date, and pro-rates the billed consumption to the appropriate month using billing statistics data. For example, if a meter is read mid-month a portion of the consumption would be attributable to the current month and the remainder to the prior month. Energy+ applies the actual GA rate against the prior month's consumption when it is available and utilizes the IESO 2nd estimate to any consumption that falls within the current month.

Any settlements that were based on the 2nd estimate will be subject to a true-up to the actual rate in the subsequent month. As a result of the lag in the settlement process a true-up on consumption is not required.

ii. The following table provides the impact of the December 2017 GA rate true up (2nd estimate vs actual). These amounts have not been recorded in the general ledger in 2017.

CND	Brant	Total
$11,460,06	$1,193.25	$12,653.31

iii. Energy+ confirms that it does not record an estimate of the CT 148 invoice prior to receipt. There is no accrual, estimate or true-up recorded.

iv. Energy+ prepares a true-up to the actual RPP and Non RPP allocation percentages for all months at year end.

In January 2018, Energy+ posted the true-up entry to the December 2017 G/L which resulted in a debit of $818,770 to accounts 1588 and 4705 with an offsetting credit to accounts 1589 and 4707.

v. The RPP and Non RPP allocation entries are based on estimate percentages until the final GA rates are known.

vi. Energy+ has updated the DVA Continuity Schedules and GA Analysis Workforms to capture the adjusting entries made to accounts 1588 and 1589 as transactions in 2017. These entries have been reversed in the principal adjustments column since these were prior period adjustments and have already been reflected in the 2017 opening balances.

OEB Staff - Settlement Proposal - Clarification Question 4

Ref: Response to 9-Staff-97

c) The Applicant provided revised GA Analysis Workforms by service territory:

i. Has the Applicant reconciled the difference identified in the Brant County's GA Analysis Workform. If so, please provide the updated GA Analysis workform.

ii. In the CND GA Analysis Workform, why hasn't the Applicant factored in the reversal of the principal adjustments it has proposed in the DVA continuity schedule as part of its analysis in Note 5? Wouldn't those amounts be captured by the transactions during 2017? Please explain and update the GA Analysis workform as needed.

RESPONSE

c)

i. Energy+ has reconciled the difference identified in Brant County's GA Analysis workform. The revised GA Analysis workform files have been provided in Excel format with the following file names:

2019 Energy+ GA-Analysis-Workform - BCP - Settlement.xlsb
2019 Energy+ GA-Analysis-Workform - CND - Settlement.xlsb
2019 Energy+ GA-Analysis-Workform - Consolidated - Settlement.xlsb

The reconciling item was caused by the inclusion of embedded generation balances from Hydro One in account 4705 during the calculation of a year-end true-up of the RPP and Non RPP allocation. The calculation should only have included balances from the IESO, as the balances from Hydro One are fully allocated to Non RPP as they are classified as GS>1000.

The resulting impact was an adjustment of $640,180 between 1588 and 1589, which have been included as principal adjustments on the revised DVA Continuity Schedules.

ii. Energy+ has revised the CND GA Analysis Workform to include the reversal of the principal adjustments in Note 5. The revised adjusted net change in principal balance accurately captures 2017 activity in the account.

OEB Staff - Settlement Proposal - Clarification Question 4

Ref: Response to 9-Staff-97

d) In response to 9-Staff-97 d) ii, it is not clear to OEB Staff why the allocation adjustment that the Applicant is referring to in this response has now been removed. What has changed to necessitate the removal of this allocation adjustment between accounts 1588 and 1589?

<u>RESPONSE</u>

The GA Analysis Workform submitted on Apr 30, 2018 incorrectly categorized ($818,770) under Note 2b “current year end unbilled to actual revenue differences“.

This amount is related to the 2017 year end true-up for the RPP and Non RPP allocation and was recorded in the G/L in 2017. As a result, this amount is considered as part of the 2017 transactions and is not a reconciling item in the GA Analysis Workform.

OEB Staff - Settlement Proposal - Clarification Question 4

Ref: Response to 9-Staff-97

e) In response to 9-Staff-97 e), the Applicant has submitted that the $1.2 million claimed for disposition in account 1588 represents the difference between RPP revenue and the cost of power attributed to RPP customers. If that is the case, then shouldn't this amount be settled with the IESO and not with ratepayers? Is there a settlement with the IESO for 2017 that has not been recorded against this account balance?

<u>RESPONSE</u>

As a result of the adjustment noted in 11 c i) the principal amount claimed for disposition in account 1588 is $579,545.

OEB Staff - Settlement Proposal - Clarification Question 5

Ref: Response to 9-Staff-100

In this response the Applicant responds to question related to account 1595.

a) The applicant has indicated that it is the first time 1595 (2016) has been brought forward for disposition, however did not confirm the same for 1595 (2014) and 1595 (2015). Please confirm that the residual balances in these accounts already have been disposed once.

RESPONSE

Energy+ confirms the residual balances in accounts 1595 (2014) and 1595 (2015) have already have been disposed through the 2018 IRM Application (EB-2017-0030).

OEB Staff - Settlement Proposal - Clarification Question 5

Ref: Response to 9-Staff-100

b) The Applicant has indicated that the claim amount for 1595 (2016) has changed because it originally included 1595 (2017) amounts because an older version of the DVA continuity schedule had been used. The claim amount in 1595 (2016) had originally been a credit to customers. However in the updated DVA continuity both the 1595 (2016) and 1595 (2017) are debits. Why did the account change from a net credit to two debits for both 1595 (2016) and 1595 (2017).

RESPONSE

The 1595 (2016) claim amount in the original submission was misstated and revised in the submission with interrogatory responses. The original submission incorrectly included a principal adjustment disposition of $549,724 in 2018, which resulted a net credit balance from over recovery. Principal disposition on 1595 (2016) was not approved beyond 2017 and the DVA Continuity has been updated to present no disposition on this account in 2018.

The DVA Continuity workbook for the original submission did not have a row for the 1595 (2017) claim amount. The principal balance amount of $49,448 was included on the row for 1595 (2016). The debit balance of this account remains unchanged in the revised submission, it has only been reclassified.

OEB Staff - Settlement Proposal - Clarification Question 6

Ref: Table 4-8, Overall OM&A Cost Trends

a) In this table the Applicant indicates that maintenance costs being allocated to capital projects has increased by 475,000 compared to 2014 (thereby decreasing OM&A). What is driving the increase in the allocation of these costs to capital projects? Aren't maintenance costs typically period costs, so why would the rate at which they are being capitalized increase?

RESPONSE

As described in Exhibit 4, Page 26 of 540, the $475,000 represents an increase in labour costs that have been allocated to capital projects, compared to the prior period, thereby resulting in a decrease in OM&A. This is principally explained by an increase in the level of capital investments. This does not reflect maintenance costs that were capitalized. Energy+ submits that perhaps this would have been better described as a decrease in maintenance operating labour expenditures due to the increased focus on capital investments, and in particular renewal capital investments.

CCC - Settlement Proposal - Clarification Question 1

Ref: CCC10, 11, 12 and 13

These questions provide detailed data for System Access, System Renewal, System Service and General Plant. Although it was not included in the questions could Energy + please provide the relevant data for 2018?

RESPONSE

Included in this response are updated tables as provided in Response to CCC 10, 11, 12, and 13 to include the 2018 Bridge Year. Energy+ notes that the Response to CCC 10, 11, 12, and 13 are based on the DSP as originally filed and do not include any revisions made through the IR process (e.g. changes to the facilities plans).

System Access Breakdown by Primary Drivers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
System Expansion	$ 6,630,732	$ 1,241,958	$ 3,853,744	$ 1,875,657	$ 1,232,670	$ 1,235,115	$ 1,518,015	$ 1,567,115	$ 1,478,095	$ 1,401,315	$ 1,566,715
New Customer Connections	$ 683,240	$ 1,009,050	$ 730,073	$ 1,419,229	$ 1,265,964	$ 1,473,100	$ 1,488,500	$ 1,470,000	$ 1,470,000	$ 1,470,000	$ 1,470,000
Metering	$ -	$ -	$ -	$ -	$ -	$ -	$ 751,092	$ 420,900	$ 427,200	$ 433,600	$ 440,100
Relocations	$ 1,062,469	$ 1,529,813	$ 3,480,487	$ 2,190,643	$ 3,100,437	$ 2,714,800	$ 766,600	$ 548,900	$ 977,000	$ 629,800	$ 651,850
System Access Total	$ 8,376,441	$ 3,780,821	$ 8,064,304	$ 5,485,529	$ 5,599,071	$ 5,423,015	$ 4,524,207	$ 4,006,915	$ 4,352,295	$ 3,934,715	$ 4,128,665
Deferred Revenue	(717,867)	(756,000)	(4,496,000)	(2,763,000)	(3,212,000)	(2,133,000)	(817,000)	(769,000)	(886,000)	(772,000)	(782,000)
System Access (Net)	$ 7,658,574	$ 3,024,821	$ 3,568,304	$ 2,722,529	$ 2,387,071	$ 3,290,015	$ 3,707,207	$ 3,237,915	$ 3,466,295	$ 3,162,715	$ 3,346,665

System Renewal Breakdown by Primary	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Overhead Rebuild	$ 2,382,484	$1,296,760	$ 2,719,878	$ 3,520,239	$3,622,718	$ 2,747,700	$3,048,000	$ 2,801,750	$ 2,408,900	$ 5,726,950	$ 5,012,100
Pole Replacements	$ 555,656	$ 619,925	$ 557,401	$ 642,503	$1,054,235	$ 833,200	$ 548,100	$ 792,400	$ 950,400	$ 949,400	$ 949,400
Line Transformers Capitalized	$ 87,974	$ 467,247	$ 306,845	$ 679,308	$ 360,752	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000
Underground Rebuild	$ 874,171	$1,105,822	$ 1,602,478	$ 2,527,892	$3,500,366	$ 994,300	$1,748,100	$ 3,273,550	$ 2,669,865	$ 195,000	$ 1,251,700
Porcelain Insulator Replacements with Polymer	$ -	$ 110,684	$ 113,498	$ 86,683	$ 266,670	$ 317,000	$ 362,000	$ 362,000	$ 362,000	$ 362,000	$ 362,000
Vault Lid Replacements	$ 247,239	$ 4,916	$ -	$ 72,697	$ 97,049	$ 132,000	$ 132,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000
Porcelain SMD-20 / Fault Tamer Replacements	$ -	$ 56,387	$ 82,370	$ 242,425	$ 138,427	$ 110,500	$ 110,500	$ 110,500	$ 110,500	$ 110,500	$ 110,500
Switchgear Replacements	$ -	$ -	$ 82,823	$ 116,334	$ 112,884	$ 85,000	$ 85,000	$ 170,000	$ 255,000	$ 255,000	$ 255,000
Pad-mounted Transformer Replacements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,000	$ 83,000	$ 83,000	$ 83,000
MTS Equipment Renewal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,000	$ 70,000	$ 70,000	$ 70,000
Load-break Switch Replacements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,000	$ 31,000	$ 31,000	$ 62,000
Misc	424,020	699,652	$ 603,524	$ 304,943	$ 317,365	$ 149,000	$ 169,000	$ 350,000	$ 550,000	$ 550,000	$ -
System Renewal Total	$ 4,571,544	4,361,392	6,068,818	8,193,024	9,470,467	5,818,700	6,652,700	8,591,200	8,006,665	8,848,850	8,671,700

System Service Breakdown by Primary Drivers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Enhanced Switching	$ 258,610	$ 98,853	$ 584,391	$ 187,583	$ 23,737	$ 298,000	$ 271,000	$ 301,000	$ 400,000	$ 240,000	$ 240,000
Feeder Improvements	$ 599,831	$ 482,456	$ 814,400	$ 530,876	$ 63,593	$ 2,233,100	$ 69,000	$ 281,600	$ 523,600	$ 181,600	$ 181,600
Enhanced Fault Detection	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,000	$ 8,500	$ 30,000	$ -	$ -
System Service Total	$ 858,441	$ 581,309	$ 1,398,791	$ 718,459	$ 87,330	$ 2,531,100	$ 367,000	$ 591,100	$ 953,600	$ 421,600	$ 421,600

General Plant Breakdown by Primary Drivers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Buildings	$ 416,000	$ 230,000	$ 84,000	$ 39,000	$ 394,000	$ 20,000	$ 4,400,000	$ 4,500,000	$ 150,000	$ 2,000,000	$ 150,000
Information System Technology	$ 162,000	$ 52,000	$ 125,000	$ 14,000	$ 34,000	$ 823,900	$ 767,000	$ 523,000	$ 850,000	$ 850,000	$ 900,000
Vehicles	$ 686,000	$ 1,543,000	$ 1,290,000	$ 857,000	$ 830,000	$ 100,000	$ 105,000	$ 543,000	$ 548,000	$ 388,000	$ 590,000
Tools and Equipment	$ 612,000	$ 848,000	$ 596,000	$ 468,000	$ 419,000	$ 95,500	$ 67,000	$ 90,000	$ 95,000	$ 100,000	$ 100,000
Office Equipment and Furniture	$ 162,000	$ 68,000	$ 45,000	$ 88,000	$ 175,000	$ 16,700	$ 4,000	$ 500,000	$ 25,000	$ 200,000	$ 25,000
Meters*	$ 697,000	$ 296,000	$ 197,000	$	320,000 $	$ 824,242	$ -	$ -	$ -	$ -	$ -
General Plant Total	$ 2,038,000	$ 2,741,000	$	2,140,000	$ 1,466,000	$ 1,852,000	$ 1,056,100	$	5,343,000	$ 6,156,000	$

Note: Meters excluded from historical totals to provide an equal comparison between 2013-

CCC - Settlement Proposal - Clarification Question 2

Ref: CCC-27

Kinetrics provided the following comments:

“In general, data quality of Cambridge and Brant areas is the same or better than the majority of local distribution utilities that Kinetrics has worked with so far. In terms of completeness, there was no asset group in which Energy + collected less data than the majority of utilities did.”

Please provide Kinetrics’ perspective on the quality and completeness of the data of the majority of local distribution utilities.

<u>RESPONSE</u>

Energy+ requested that Kinectrics provide comments on this follow up question and received the following response:

“The following table summarizes the comparison between Energy+ and the majority of local distribution utilities, in terms of data quality and completeness”

Data Type	Age		Inspection		Test		Service Record	
	Energy+	Majority of LDC	Energy+	Majority of LDC	Energy+	Majority of LDC	Energy+	Majority of LDC
Station Transformers	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Station Circuit Breakers	Yes	Yes	Yes	Yes	Yes		Yes	
Voltage Regulators	Yes	Yes	Yes					
Capacitors	Yes	Yes	Yes					
OH Line Switches	Yes	Yes	Yes					
OH Line Reclosers	Yes	Yes	Yes					
Pole Mounted Transformers	Yes	Yes					Yes	
Wood Poles	Yes	Yes			Yes			
Concrete Poles	Yes	Yes						
Steel Poles	Yes	Yes						
Pad Mounted Transformers	Yes	Yes	Yes	Yes			Yes	
Pad Mounted Switchgear	Yes	Yes	Yes	Yes				
Vault Transformers	Yes	Yes					Yes	
Submersible Transformers	Yes	Yes					Yes	
UG primary Cables (km)	Yes	Yes						

CCC - Settlement Proposal - Clarification Question 3

Ref: CCC-32

Please clarify how Energy + went about reducing the capital budget by $1 million. Was it a top down (look for $1 million in reductions or deferrals) or was it a bottom up approach?

<u>RESPONSE</u>

Energy+ made a top down decision to look for reductions in the capital budget by $1 million dollars while factoring in customer feedback, the results of the Asset Condition Assessment, and assessing implications to the Distribution System Plan.

VECC - Settlement Proposal - Clarification Question 1

Ref: 3-VECC-17

Please provide the customer/connection count by rate class as of June 30, 2018.

RESPONSE

The following is the Energy+ customer/connection count by rate class as of June 30, 2018.

Energy+ Customer Counts /Connection

Rate Class	Jun-18
Residential	57,929
GS < 50	6,379
GS > 50 - 999 kW	652
GS > 1000 kW	21
GS > 50 - 4,999 kW	117
Large Users	2
USL	486
Sentinel	163
Streetlights	16,155
Embedded Generation	2
Total	82,559

VECC - Settlement Proposal - Clarification Question 2

Ref: 3-VECC-20

a) For those months in 2018 where the data is available, please provide the comparable values for the unemployment variable.

RESPONSE

The following provides the values for the unemployment variable from January 2018 to October 2018

Jan-18	31.6
Feb-18	36.5
Mar-18	41.7
Apr-18	42.8
May-18	43.4
Jun-18	41.9
Jul-18	41.4
Aug-18	38.5
Sep-18	34.3
Oct-18	31.7

VECC - Settlement Proposal - Clarification Question 3

Ref: 3-Staff-53

4-Staff-64 a) i) - Updated CND_OEB LRAMVA Work Form

a) Please confirm that the 2016 values set out in Tab 9 of the updated LRAMVA Work Form represent the difference between: i) the monthly maximum peak demand based on the sum of the hourly metered (i.e., billing demand) load plus the hourly self-generation and ii) the metered monthly peak load (i.e., billing demand).
b) If not, please provide a table that sets out these values for each month in 2016.
c) Please confirm whether the 2017 values set out in Tab 9 of the updated LRAMVA Work Form represent the difference between: i) the maximum monthly peak demand based on the sum of the hourly metered (i.e., billing demand) load plus the hourly self-generation and ii) the metered monthly peak load (i.e., billing demand).
d) If not, please provide a table that sets out these values for each month in 2017.
e) What was the maximum hourly combined output of the two generators for each month in 2016 and 2017?
f) What was the minimum hourly combined output of the two generators for each months in 2016 and 2017?

<u>RESPONSE</u>

a) The 2016 values set out in Tab 9 of the updated LRAMVA Work Form represent the difference between: i) the hour in each month with the highest sum of billing demand and self-generation and ii) the hour in each month with the highest billing demand. Please refer to the Response to OEB Staff Follow-Up Question Number 6.
b) Please refer to OEB Staff Follow-Up Question Number 6.
c) The 2017 values set out in Tab 9 of the updated LRAMVA Work Form represent the difference between: i) the hour in each month with the highest sum of billing demand and self-generation and ii) the hour in each month with the highest billing demand. Please refer to the Response to OEB Staff Follow-Up Question Number 6.
d) Please refer to OEB Staff Follow-Up Question Number 6.
e) Please refer to table below.
f) Please refer to table below.

[redacted]

[redacted]

[redacted]

VECC - Settlement Proposal - Clarification Question 4

Ref: 4-Staff-65 a) and b)
4-Staff-64 a) i) - Updated BCP_OEB LRAMVA Work Form

a) Please explain more fully why the fact Direct Market Participants did not participate in the IESO's provincially funded CDM programs offered by Energy+ during 2014 to 2017 gives rise for the need for the 1,254,827 kWh adjustment to the CND LRAMVA threshold as opposed to simply re-assigning the threshold attributed to the Direct Market Participant to the relevant customer classes.

b) Please provide a specific reference to EB-2010-0125 record regarding the 1,494,000 kWh threshold used for the Brant County LRAMVA claim.

RESPONSE

a) In retrospect, Energy+ agrees that the CDM threshold for the CND Direct Market Participants should have been allocated to the relevant customer classes, specifically the GS>50-999 kW and GS 1,000-4,999 customer classes.

b) The 1,494,000 is the estimated 2011 CDM results for CDM from JT1.1 p.2, JT1.3 p.4, and JT 1.5 p.7 of the BCP Undertakings (File name: Brant_Undertaking Resp_JT1.1 - JT1.14_20110323.PDF). Received by the OEB 2011-03-23.

VECC - Settlement Proposal - Clarification Question 5

Ref: 7-VECC-44

a) In which customer classes are the seven GS customers and for each class how many connections and meters are associated with the customers?

<u>RESPONSE</u>

Out of the seven (7) GS customers, six (6) customers are in the GS >1000-4999 kW Class and one (1) customer is in the GS >50-999kW Class.

For the GS>1000-4999kW Class, there are 12 connections (2 per customer) and 13 meters.

For GS>50-999kW Class, there are two connections and 2 meters.

VECC - Settlement Proposal - Clarification Question 6

Ref: 3-VECC-19 a) and Updated Load Forecast Model (LFM) 7-Staff-76 b) and Updated Cost Allocation Model (CAM) 7-VECC-47 a)

b) For each of the supply points discussed in VECC-47 a) under Hydro One Networks Inc. # 2 (Brant Service Territory), the text indicates that is “normally” supplied from Hydro One owned facilities? Is power ever supplied to HON at these points using Energy+’s distribution facilities?

i. If yes, under what circumstances?

ii. If yes, why shouldn’t this “customer” be allocated a portion of the costs of Energy+’s distribution network?

RESPONSE

i. In the case of Hydro One Networks Inc. # 2 (Brant Service Territory), there were no instances found when power was supplied using alternative feeders and/or Transformation (>50kV) owned by Energy+.

ii. The answer to part (i) was no.

VECC - Settlement Proposal - Clarification Question 7

Ref: **Updated Load Profile Model (2006 HON data for 2019)**
7-Staff-76 b) and Updated Cost Allocation Model (CAM)
7-Staff 84 a)
7-Staff 85 a)

a) Please provide revised response to Staff 84 a) based on 2017 data as used in the updated Load Forecast and updated CAM.

RESPONSE

a) The following provides a revision to the table that was included in response to Staff 84 a). The table has been revised to reflect 2017 data used in the updated Load Forecast and updated CAM.

[redacted]

[redacted]

VECC - Settlement Proposal - Clarification Question 7

Ref: Updated Load Profile Model (2006 HON data for 2019)
7-Staff-76 b) and Updated Cost Allocation Model (CAM)
7-Staff 84 a)
7-Staff 85 a)

b) Please provide a revised response to Staff 85 a) based on the updated Load Forecast and updated CAM.

RESPONSE

The following provides a revision to the tables that were included in response to Staff 85 a). The tables have been revised based on the updated Load Forecast and updated CAM.

GS > 50 to 999 kW

	Load Profile Model	Cost Allocation Model	Difference	Reason
1 CP	73,655	75,161	1,506	Impact of WMPs assigned to this class
4 CP	292,011	298,034	6,023	
12 CP	847,739	865,809	18,069	
1 NCP	82,827	84,332	1,506	
4 NCP	326,869	332,892	6,023	
12 NCP	954,919	972,988	18,069	

GS > 1,000 to 4,999 kW

	Load Profile Model	Cost Allocation Model	Difference	Reason
1 CP	36,416	40,572	4,156	Impact of WMPs assigned to this class
4 CP	142,076	158,700	16,624	
12 CP	396,280	446,153	49,872	
1 NCP	40,787	44,943	4,156	
4 NCP	155,783	172,407	16,624	
12 NCP	444,745	494,617	49,872	

Large Use

	Load Profile Model	Cost Allocation Model	Difference	Reason
1 CP	20,848	20,848	-	Impact of Standby Demand Units
4 CP	86,707	88,898	2,191	
12 CP	259,575	290,018	30,443	
1 NCP	26,546	26,546	-	
4 NCP	102,987	105,178	2,191	
12 NCP	286,587	317,030	30,443	

VECC - Settlement Proposal - Clarification Question 7

Ref: Updated Load Profile Model (2006 HON data for 2019)
7-Staff-76 b) and Updated Cost Allocation Model (CAM)
7-Staff 84 a)
7-Staff 85 a)

c) With respect to Staff 85 a), please explain how, for the GS 50-999 and GS 1,0004,999 classes the adjustment to incorporate the WMPs was calculated. In doing so, please explain why the % change in each of allocator's values is not the same (as one might expect if the adjustment was done by including the WMP energy in the total energy used to create the load profile).

<u>RESPONSE</u>

In the Load Forecast the kW forecast for the WMPs has been held constant at the 2017 value of 67,942 kW. Based on 2017 data, there is one WMP in the GS 50-999 class for distribution services. This customer represents 26.6% of the 67,942 kW or 18,069 kW. The remaining (i.e. 49,872 kW) is in the GS 1,000-4,999 class which represents the value for three customer. The adjustment to the GS 50-999 demand data in the cost allocation model to incorporate the WMP assumes the 18,069 kW impacts the 12 CP and 12 NCP. 18,069 kW divided by 3 impacts the 4 CP and 4 NCP and 18,069 kW divided by 12 impacts the 1 CP and 1 NCP. The same process is used in the GS 1,000-4,999 class with the 49,872 kW impacting the 12 CP and 12 NCP and the other demand units are adjusted with the same approach. Energy+ did not include the WMP energy in the total energy used to create the load profile since the precision of the kWh associated with the WMP was not at the same level as the kW value since the kWh value is not used for billing purposes.

VECC - Settlement Proposal - Clarification Question 8

Ref: TMMC-4
TMMC Response to VECC 12.5
Updated CAM Model, Tab I6.1 (Revenue)
Updated LF Model, Rate Class Load Model Tab, Cell D11

Preamble: The response to TMMC-4, part 3 states:

The revenue requirement for rate setting purposes is determined in the following manner. The first step is to calculate the revenue that would be achieved from the Large User class assuming the demand from Standby does not exist. The calculated revenue amount is the current Large User rates increased by the average Energy+ 2019 distribution rate increase (i.e. 3.3%) times the Large User demand excluding Standby demand. The calculated revenue could be classified as revenue at existing rates increased by the average rate increase. (emphasis added)

a) Please confirm that, contrary to the response to TMMC-4, the 361,276 kW of billing demand for the Large Use class used in the updated CAM does include the 30,443 kW adjustment for Standby demand.

RESPONSE

Energy+ confirms that the 361,276 kW of billing demand for the Large Use class outlined in the updated LF model includes the 30,443 kW adjustment for Standby demand. However, for the purposes of calculating revenue at existing rates there has not been any existing revenue attributed to the 30,443 kW which is consistent with the statement provided in the Preamble.