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

Table of Contents

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. <u>Introduction</u>

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		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: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: 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	$3,093.34
and Class Specific Revenue Requirement	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)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)
1	Residential	kWh	58,677	461,453,716	-	$ 19,437,846	$ 19,437,846	$ -	100.00%	0.00%	
2	GS <50	kWh	6,451	193,967,011	-	$ 4,238,997	$ 1,153,007	$ 3,085,990	27.20%	72.80%	
3	GS> 50- 999 kW	kW	801	491,288,356	1,568,556	$ 6,518,528	$ 949,516	$ 5,569,012	14.57%	85.43%	$ 163,077
4	GS> 1,000 - 4,999 kW	kW	30	229,378,990	588,206	$ 2,196,124	$ 319,232	$ 1,876,892	14.54%	85.46%	$ 348,498
5	Large Use	kW	2	145,141,006	361,276	$ 1,067,091	$ 221,025	$ 846,067	20.71%	79.29%	
6	Street Light	kW	16,260	3,798,281	10,945	$ 537,111	$ 369,970	$ 167,142	68.88%	31.12%	
7	Sentinel	kW	168	126,989	343	$ 20,145	$ 5,685	$ 14,460	28.22%	71.78%	
8	Unmetered Scattered Load	kWh	499	2,273,988	-	$ 67,343	$ 34,804	$ 32,539	51.68%	48.32%	
9	Embedded Distributor Hydro One - CND	kW	2	12,605,162	24,387	$ 42,784	$ -	$ 42,784	0.00%	100.00%	
10	Embedded Distributor Waterloo North Hydr	kW	1	58,104,381	114,657	$ 156,258	$ -	$ 156,258	0.00%	100.00%	
11	Embedded Distributor Hydro One 1 - BCP	kW	1	12,191,720	29,995	$ 30,158	$ 689	$ 29,469	2.28%	97.72%	
12	Embedded Distributor Brantford Power - BC	kW	1	347,757	1,075	$ 12,649	$ -	$ 12,649	0.00%	100.00%	
13	Embedded Distributor Hydro One 2 - BCP	kW	4	43,274,122	102,973	$ 2,754	$ 2,754	$ -	100.00%	0.00%	
14			-	-	-						
15			-	-	-						
16			-	-	-						
17			-	-	-						
18			-	-	-						
19			-	-	-						
20			-	-	-						
										Total Transformer Ownership Allowance	$ 511,575

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

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

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Forecast	2019
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

			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)	$ 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?