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September 14, 2018

Delivered by Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2701
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: OEB File No.: EB-2017-0071
PUC Distribution Inc. ("PUC") – 2018 Rates Application
Correspondence from PUC and Settlement Proposal

Pursuant to Procedural Order No. 1, please find the enclosed correspondence from PUC along with their Settlement Proposal and related supporting documentation in regards to this matter.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Original Signed by John A. D. Vellone
John A.D. Vellone

cc: Intervenors of record in EB-2017-0071

EB-2017-0071

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 PUC Distribution Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2018.

PUC DISTRIBUTION INC.

SETTLEMENT PROPOSAL

SEPTEMBER 14, 2018

PUC Distribution Inc.

EB-2017-0071

Settlement Proposal

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APPENDICES

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Appendix F – Rate Rider for Embedded Generation Adjustment
Appendix G – Bill Impacts

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:

PUC_2018-Settlement_Tariff-Schedule-and-Bill-Impact-Model
PUC_2018_Settlement_Cost_Allocation_FINAL
PUC_2018_DVA_Continuity_Schedule_Settlement FINAL
2018 PUC Load Forecast Model Settlement
PUC_2018 Income Tax_PILs_Settlement_WF Tab T4 – FINAL
PUC_2018_Settlement_RTSR_Workform_FINAL
PUC_2018_Settlement_Rev_Reqt_Work_Form_FINAL
PUC_2018_Settlement_Filing_Requirements_Chp2_App

PUC Distribution Inc.

EB-2017-0071

Settlement Proposal

Filed with OEB: September 14, 2018

PUC Distribution Inc. (the "Applicant" or "PUC") filed a complete cost of service application with the Ontario Energy Board ("OEB" or the "Board") on March 29, 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 PUC Distribution Inc. charges for electricity distribution and other charges, to be effective May 1, 2018. (Board Docket Number EB-2017-0071) (the "Application"). By Decision dated May 1, 2018, the Board determined that it would not make the Applicant's rates interim.

The Board issued and PUC Distribution Inc. published a Notice of Hearing dated May 9, 2018, and Procedural Order No. 1 on July 4, 2018, the latter of which required the parties to the proceeding to develop a draft issues list and scheduled a Settlement Conference for August 21-23, 2018.

PUC filed its interrogatory responses with the Board on August 9, 2018, pursuant to which PUC updated several models and submitted them to the Board as Excel documents. PUC filed corrections to certain interrogatory responses on August 17, 2018. On August 17, 2018, OEB staff submitted a proposed issues list (the "Issues List") as agreed to by the parties. This Settlement Proposal is filed with the Board in connection with the Application and is organized in accordance with the Issues List.

Further to the Board's Procedural Order No. 1, a settlement conference was convened on August 21, 2018, and continued to August 23, 2018, 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").

Andrew Pride acted as facilitator for the settlement conference which lasted three days.

PUC and the following intervenors (the "Intervenors"), participated in the settlement conference:

> Consumers Council of Canada (CCC");
> School Energy Coalition ("SEC"); and
> Vulnerable Energy Consumers Coalition ("VECC").

PUC and the Intervenors are collectively referred to below as the "Parties".

Ontario Energy Board staff ("OEB staff") also participated in the settlement conference. The role adopted by OEB staff is set out in page 5 of the Practice Direction. Although OEB staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB staff who did participate in the settlement conference are bound by the same confidentiality requirements that apply to the Parties to the proceeding.

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 later in this Preamble, this agreement is subject to a condition subsequent, that if it is not accepted by the Board in its entirety, then unless amended by the Parties it is null and void and of no further effect. In entering into this agreement, 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.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Practice Direction. The Parties acknowledge that this settlement proceeding is confidential in accordance with the OEB's Practice Direction on settlement conferences. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the Board's Practice Direction on Confidential Filings, and the rules of that latter document do not apply. Instead, in this settlement conference, and in this Agreement, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the settlement proceeding, 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 strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need 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, the Parties agree that "attendees" is deemed to include, in this context, persons who were not physically in attendance at the settlement conference but were a) any persons or entities that the Parties engage 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.

This Settlement Proposal provides a brief description of each of the settled issues together with references to the evidence. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include (a) additional information included by the Parties in this Settlement Proposal, and (b) the Appendices to this document. The supporting Parties for settled issue agree that the evidence in respect of that settled issue is sufficient in the context of the overall settlement to support the proposed settlement, and the sum 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.

There are Appendices to this Settlement Proposal which provide further support for the proposed settlement. The Parties acknowledge that the Appendices were prepared by PUC, with the exception of Appendix B, which was prepared by SEC and updated by PUC to reflect this settlement proposal. While the Intervenors and OEB Staff have reviewed the Appendices, the Intervenors are relying on the accuracy of the underlying evidence in entering into this Settlement Proposal.

Outlined below are the final positions of the Parties following the settlement conference. For ease of reference, this Settlement Proposal follows the format of the Issues List dated August 17, 2018.

The Parties are pleased to advise the Board that they have reached a full agreement with respect to the settlement of all of the issues in this proceeding. Specifically:

"Complete Settlement" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the Board, the Parties will not adduce any evidence or argument during the oral hearing in respect of these issues.	# issues settled: **All**
"Partial Settlement" means an issue for which there is partial settlement, as PUC Distribution Inc. and the Intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the Board, the Parties who take any position on the issue will only adduce evidence and argument during the hearing on those portions of the issues not addressed in this Settlement Proposal.	# issues partially settled: **None**
"No Settlement" means an issue for which no settlement was reached. PUC Distribution Inc. 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: **None**

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 PUC is a party to such proceeding.

Where in this Settlement Proposal, the Parties “Accept” the evidence of PUC, or the Parties or PUC “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.

1.0 Summary

In reaching this complete settlement, the Parties have been guided by the Filing Requirements for 2018 rates, the Issues List dated August 17, 2018, 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 (Handbook).

This Settlement Proposal reflects a complete settlement of the issues in this proceeding.

Between 2013-2017, PUC has found that its costs to deliver safe, reliable distribution service to its customers have exceeded the costs included in rates. Despite a concerted effort to control those costs, PUC's cost structure remains higher than its rate structure. The Parties believe this is not sustainable in the long term. This settlement, if approved by the Board, when combined with a continued focus on cost control and productivity by PUC, will facilitate the alignment of rates and costs over the next five years, and thus will benefit customers.

PUC specifically advises the Board and the Parties that, based on its internal analysis, the revenue requirement and capital plan resulting from this Settlement Proposal would, if approved, provide sufficient resources to PUC to provide safe and reliable distribution service to its customers.

In this settlement, PUC has made changes to its Revenue Requirement as depicted below in Table 1.

Table 1 - 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	$5,975,027	$5,993,155	$18,128	$5,978,287	-$14,868
	Regulated Rate of Return	6.00%	6.00%	0.00%	6.00%	0.00%
Rate Base & Capital Expenditures	Rate Base	$99,603,703	$99,905,905	$302,202	$99,658,054	-$247,851
	Net Fixed Assets	$92,717,901	$93,171,152	$453,251	$92,962,875	-$208,277
	Working Capital Base	$91,810,703	$89,796,719	-$2,013,984	$89,269,060	-$527,659
	Working Capital Allowance	$6,885,803	$6,734,754	-$151,049	$6,695,180	-$39,574
Operating Expenses	Amortization	$3,783,956	$3,783,956	$0	$3,780,329	-$3,627
	Taxes/PILs (Grossed Up)*	$366,429	$333,286	-$33,143	$586,716	$253,430
	OM&A	$11,886,833	$11,974,633	$87,800	$11,474,633	-$500,000
Revenue Requirement	Service Revenue Requirement	$22,081,245	$22,154,030	$72,785	$21,888,965	-$265,065
	Other Revenue	$2,389,661	$2,800,114	$410,453	$2,698,600	-$101,514
	Base Revenue Requirement	$19,691,584	$19,353,916	-$337,668	$19,190,365	-$163,551
	Grossed Up Revenue Deficiency	$3,679,687	$3,511,067	-$168,620	$3,354,750	-$156,317

* The Taxes/PILs Grossed Up of $586,716 is offset through the PILs rate rider discussed in Appendix E.

The Bill Impacts as a result of this settlement agreement are summarized below in Table 2.

Table 2 - Summary of Bill Impacts

Customer Class	kWh	kW	September 30, 2018 Bill Amount	October 1, 2018 Bill Amount	Difference	Total Bill Impact %	Distribution Bill Impact %
Residential	750	0	$102.50	$105.01	$2.51	2.45%	20.62%
Residential (10th percentile)	308	0	$52.99	$57.90	$4.91	9.27%	28.90%
General Service Less Than 50 kW	2,000	0	$263.18	$269.29	$6.11	2.32%	22.30%
General Service 50 to 4,999 kW	57,220	145	$9,119.96	$9,106.90	-$13.06	-0.14%	16.97%
Unmetered Scattered Load	3,600	0	$650.63	$654.13	$3.51	0.54%	12.90%
Sentinel Lighting	50	1	$43.18	$46.09	$2.91	6.73%	12.22%
Street Lighting	199,852	585	$67,608.49	$49,234.43	-$18,374.06	-27.16%	-44.81%

The impact of the settlement agreement in regards to Capital Expenditures and OM&A is summarized below in Table 3.

Table 3 - Summary of Capital Expenditures and OM&A

Description		Application	Interrogatories	Variance	Settlement	Variance
		(A)	(B)	(C)=(B)-(A)	(D)	(E)=(D)-(B)
Capital Expenditures	Gross Fixed Assets (Average)	$108,487,326	$108,943,319	$455,993	$108,733,229	-$210,090
	Accumulated Depreciation (Average)	-$15,769,425	-$15,772,167	-$2,742	-$15,770,354	$1,813
OM&A		$11,886,833	$11,974,633	$87,800	$11,474,633	-$500,000

As part of the settlement, the Parties have agreed to implement two new rate riders. First, the Parties have agreed to the creation of a Rate Rider for Embedded Generation Adjustment applicable to Account 1580, which returns to customers, on a per kWh basis, the amount collected for the Wholesale Market Service Charge and the Rural and Remote Electricity Rate Protection charge on a forecast of embedded generation. The rate rider accounts for embedded generation, subject to a true-up, and is further described in Section 4.2 and at Appendix F. Second, the Parties have agreed to a rate rider to credit customers the full benefits of the tax loss carry-forward amount of $3,493,253. This rate rider is further described in Section 2.1(f) and at Appendix E.

In addition for the purposes of settling all issues in this proceeding, PUC has agreed to file the Shareholder Agreement between the City of Sault Ste. Marie and PUC Inc. dated July 25, 2000, as amended and to provide the publically available 2017 Audited Financial Statements of PUC Services and PUC Inc.

This Settlement Proposal reflects the Parties' agreement on an effective date for new rates of October 1, 2018.

Finally, the Parties agree that the OEB's policy as set out in the Report of the Ontario Energy Board titled *Wireline Pole Attachment Charges* dated March 22, 2018 (EB-2015-0304) regarding changes to the province-wide pole wireline pole attachment charge as well as the OEB's letter dated July 20, 2018 to all rate-regulated licensed electricity distributors regarding accounting guidance on wireline pole attachment charges should apply to PUC. Since PUC does not have an OEB-approved LDC-specific charge in place, it is required as a term of its distribution license to use this province-wide charge. This will result in a pole attachment charge (for non-wireless attachments) of $28.09 (per attacher per year) until December 31, 2018 and $43.63 effective January 1, 2019.

The Parties believe that, since there are no areas of disagreement among the Parties, if this Settlement Proposal is accepted by the Board there are no issues which would require the Board to hold an oral hearing.

Based on the foregoing, and the evidence and rationale provided below, the Parties agree that this Settlement Proposal is appropriate in that overall rate impacts are minimal while allowing PUC to provide value to customers in the areas of reliability, customer service and communication, and asset maintenance and replacement. The Parties recommend its acceptance by the Board. Please refer to Appendix A for the schedule of draft tariffs resulting if this settlement is accepted by the Board.

2.0 Planning

2.1 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.*

Complete Settlement: For the purposes of the settlement of all of the issues in this proceeding, PUC agrees to adjust its 2018 rate base and Test Year capital plan to reflect the following changes:

- PUC agrees to reduce its Test Year capital additions by $420,179. This would result in a 2018 Capital Additions of $5,388,176.

This reduction in capital additions results from the removal of the costs associated with *Project #7 – Substation 16 Rebuild* in the Test Year given that Substation 16 will not be in service in 2018, as further described in response to interrogatories 2-CCC-42 and 2-Staff-28b and Exhibit 2/App. G/Project #7.

With the above adjustment, the Parties 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 as more fully detailed in Exhibit 1 at Section 2.1.6.1, Appendix 10 and Exhibit 2 Appendix 2-H;

- The past and planned productivity initiatives of PUC as more fully detailed in Exhibit 1 at Section 2.1.6.2;

- PUC's benchmarking performance as more fully detailed in Exhibit 1 at Section 2.1.7.1 and Appendix 1-4. In this regard, the Parties also considered PUC's performance relative to comparable northern LDCs based on a total cost of delivery, including transmission and distribution, as shown in Appendix B;

- PUC's past reliability and service quality performance as well as PUC's targets for performance in the Test Year as more fully detailed in Exhibit 1, Section 2.1.7.1 and Exhibit 2, Section 2.2.2.7 and Appendix 2-H;

- The total impact on distribution rates, as more fully detailed in Appendix I of this settlement agreement;

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

- PUC's performance meeting government mandated obligations as more fully detailed in Exhibit 1 at Section 2.1.7.1 and Appendix 4;

- PUC's targets and objectives as more fully detailed in Exhibit 1 at Section 2.1.7.1, Appendix 12 and Exhibit 2 Appendix 2;

The Parties further agree that, subject to the adjustment noted above, the Distribution System Plan filed in this proceeding, combined with the resources made available to PUC in the Test Year under the terms of this Settlement Proposal, provide a foundation to PUC in the Test Year to continue to: (a) pursue continuous improvement in productivity; (b) maintain system reliability and service quality; and (c) maintain reliable and safe operation of its distribution system.

Appendix D of this Settlement Proposal provides a final Fixed Asset Continuity Schedule to reflect this settlement.

Evidence:

Application: Exhibit 1 Sections 2.1.2, 2.1.3, 2.1.4, 2.1.5.4, 2.1.6; Exhibit 2 in its entirety, in particular Section 2.2.2 and Exhibit 2 Appendix 2-A

IRRs: 1-Staff-7, 1-CCC-6, 1-SEC-15, 1-SEC-17, 1-SEC-20, 1-SEC-21, 1-VECC-4, 2-Staff-8, 2-Staff-9, 2-Staff-10, 2-Staff-11, 2-Staff-12, 2-Staff-13, 2-Staff-14, 2-Staff-15, 2-Staff-16, 2-Staff-17, 2-Staff-18, 2-Staff-19, 2-Staff-20, 2-Staff-22, 2-Staff-23, 2-Staff-28, 2-Staff-30, 2-Staff-31, 2-Staff-32, 2-Staff-33, 2-Staff-35, 2-Staff-36, 2-Staff-38, 2-Staff-39, 2-Staff-41, 2-Staff-42, 2-Staff-43, 2-CCC-19, 2-CCC-20, 2-CCC-22, 2-CCC-23, 2-CCC-24, 2-CCC-25, 2-CCC-26, 2-CCC-27, 2-CCC-28, 2-CCC-29, 2-CCC-30, 2-CCC-31, 2-CCC-32, 2-CCC-33, 2-CCC-34, 2-CCC-35, 2-CCC-36, 2-CCC-37, 2-CCC-38, 2-CCC-39, 2-CCC-40, 2-CCC-41, 2-CCC-42, 2-CCC-43, 2-CCC-44, 2-CCC-46, 2-VECC-9, 2-VECC-10, 2-VECC-11, 2-VECC-12, 2-VECC-13, 2-VECC-14, 2-VECC-15,

Appendices to this Settlement Proposal:

Appendix D – Appendix 2-BA Fixed Asset Continuity Schedule

Models: PUC_2018_Settlement_Filing_Requirements_Chp2_App

Supporting Parties: All

2.2 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, PUC agrees to reduce its proposed OM&A expenses in the Test Year by $500,000 ($10,926 of which represents a reduction in transfer pricing as a result of a correction noted in the settlement of issue 2.1(d) below) to $11,543,633.

Based on the foregoing, and the evidence filed by PUC, the Parties 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 as more fully detailed in Exhibit 1 at Section 2.1.6.1, Appendix 10 and Exhibit 2 Appendix 2-H ;

- The past and planned productivity initiatives of PUC as more fully detailed in Exhibit 1 at Section 2.1.6.2 ;

- PUC's benchmarking performance as more fully detailed in Exhibit 1 at Section 2.1.7.1 and Appendix 1-4. In this regard, the Parties also considered PUC's performance relative to comparable northern LDCs based on a total cost of delivery, including transmission and distribution, as shown in Appendix B;

- PUC's past reliability and service quality performance as well as PUC's targets for performance in the Test Year as more fully detailed in Exhibit 1, Section 2.1.7.1 and Exhibit 2, Section 2.2.2.7 and Appendix 2-H ;

- The total impact on distribution rates, as more fully detailed in Appendix I of this settlement agreement;

- The changes in capital spending as described under Issue 1.1 of this Settlement Proposal;

- PUC's performance meeting government mandated obligations as more fully detailed in Exhibit 1 at Section 2.1.7.1 and Appendix 4;
- PUC's targets and objectives as more fully detailed in Exhibit 1 at Section 2.1.7.1, Appendix 12 and Exhibit 2 Appendix 2

Evidence:

Application: Exhibit 1 Sections 2.1.2, 2.1.3, 2.1.4, 2.1.5.5, 2.1.6; Exhibit 2 Appendix 12; Exhibit 4 Sections 2.4.1 to 2.4.3.7

IRRs: 1CCC-7, 1-CCC-8, 1-CCC-10, 1-CCC-13, 1-CCC-14, 1-CCC-17, 1-SEC-1, 1-SEC-2, 1-SEC-10, 1-SEC-11, 1SEC-19, 1SEC-20, 1-SEC-21, 1SEC-22, 1-SEC-23, 1-SEC-24, 1-SEC-32, 1-SEC-33, 1SEC-35, 1VECC-2, 1-VECC-4, 1-VECC-8, 2-STAFF-13, 2-STAFF-18, 2-STAFF-22, 2-STAFF-24, 2-STAFF-25, 2-STAFF-34, 2-STAFF-37, 2-STAFF-40, 2-CCC-21, 2-CCC-23, 2-CCC-31, 4-STAFF-50, 4-STAFF-51, 4-STAFF-53, 4-STAFF-54, 4-STAFF-55, 4-STAFF-56, 4-STAFF-57, 4-STAFF-58, 4-STAFF-59, 4-STAFF-61, 4-STAFF-62, 4-STAFF-69, 4-CCC-48, 4-CCC-50, 4-CCC-51, 4-CCC-53, 4-CCC-54, 4-SEC-36, 4-SEC-38, 4-SEC-39, 4-SEC-40, 4-VECC-31, 4-VECC-32, 4-VECC-33, 4-VECC-34, 4-VECC-35

Appendices to this Settlement Proposal: None

Models: PUC_2018_Settlement_Filing_Requirements_Chp2_App

Supporting Parties: All

3.0 REVENUE REQUIREMENT

3.1 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 Parties 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 Parties agree that the rate base calculations, 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 Parties agree that the working capital calculations, 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 Parties agree that the cost of capital calculations, as updated to reflect this Settlement Proposal, are reasonable and have been appropriately determined in accordance with OEB policies and practices.

d) *Other Revenue:* In response to interrogatory 4-VECC-31(e) PUC explained that when calculating it's transfer pricing between PUC and its affiliates it had grossed up the entire cost of capital in respect of building-related charges (which affects PUC's forecast of Other Revenues) and vehicle and other asset charges (which affects PUC's forecasts of OM&A). The Parties have agreed that for the purposes of transfer pricing the 7.98% Cost of Capital grossed up for PILs should be revised to gross up the ROE portion only, consistent with the RDI Full Absorption Cost Allocation report at Exhibit 4 Appendix 9. This correction results in a revised Cost of Capital used for the purposes of transfer pricing, grossed up for PILs, of 7.16%. With that adjustment, shared service charges - which affect Other Revenue and OM&A - are adjusted to reflect a gross up on the ROE portion only, not the entire cost of capital as outlined in response to interrogatory 4-VECC-31(e). This revision to transfer pricing lowers Other Revenue by $101,515 and lowers OM&A operating costs by $10,926, as outlined in Table 4 below.

Table 4 – Cost of Capital for Purposes of Transfer Pricing

	%	Deemed Rate	Return	Tax Gross Up	Final Rates
Short Term Debt	4.0%	2.07%	0.08%		0.08%
Long Term Debt	56.0%	3.91%	2.19%		2.19%
Equity	40.0%	8.98%	3.59%	26.50%	4.89%
					7.16%

Table 5 – Impact of Cost of Capital Change to Building Charges

Cost of Capital Original Application		7.98%
Cost of Capital Settlement		7.16%
Reduction		0.819%
Capital Cost of Facilities		$23,137,285
Cost of Capital - Facilities		$189,564
PUC Distribution portion	46.45%	$88,049.33
Other Revenue Reduction		**$101,515**

Table 6 – Impact of Cost of Capital Change to OM&A

NBV	$5,682,605
ROE @ 7.98%	$453,472
ROE @ 7.16%	$406,875
Operating Costs @ 7.98%	$106,257
Operating Costs @ 7.16%	$95,331
Reduction	-$10,926

Subject to these adjustments, the Parties agree that the other revenue calculations, as updated to reflect this Settlement Proposal, are reasonable and have been appropriately determined in accordance with OEB policies and practices.

e) *Depreciation:* The Parties 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:* PUC will adjust its PILs calculation to eliminate the impact of its tax loss carry-forwards (i.e. PILs will be calculated assuming no loss carry-forward is available). Instead, PUC will implement a new standalone rate rider to credit customers the full benefits of grossed-up tax loss carry-forward amounts of $3,493,253 as set out in IRR 4-STAFF-70, 2017 PILs Return, and Schedule 4. This rate rider is further described at Appendix E. The rate rider will remain in place for a 19-month period commencing October 1, 2018 and ending April 30, 2020 to align with a rate year. The Parties intend that the timing of the rate rider will match the period of time over which PUC will receive tax reductions from those same loss carry-forwards, while ensuring that PUC recovers in rates an appropriate amount of PILs once the loss carry-forward reductions are no longer available to PUC.

Subject to these adjustments, the Parties 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. The PILs workform reflecting this Settlement Proposal is provided as part of the supporting material in file named PUC_2018 Income Tax_PILs_Settlement_WF Tab T4 - FINAL.

Evidence:

Application: Exhibit 1 Section 2.1.5.1, Section 2.1.5.4, Section 2.1.5.6; Exhibit 2 Section 2.2.1.1 to 2.2.2.4; Exhibit 3 Section 2.3.3; Exhibit 4 Section 2.4.4, Section 2.4.5; Exhibit 5; Exhibit 6

IRRs: 1-STAFF-7, 1-CCC-2, 1-CCC-4, 1-CCC-8, 2-STAFF-8, 2-STAFF-10, 2-STAFF-11, 2-STAFF-13, 2-STAFF-17, 2-STAFF-22, 2-CCC-19, 2-CCC-29, 2-CCC-31, 2-CCC-41, 2-CCC-42, 2-VECC-10, 2-VECC-12, 3-STAFF-48, 3-VECC-28, 4-STAFF-50, 4-STAFF-57, 4-STAFF-58, 4-STAFF-59, 4-STAFF-60, 4-STAFF-61, 4-SEC-41, 4-VECC-32, 5-VECC-38

Appendices to this Settlement Proposal: Appendix E

Models: PUC_2018_Settlement_Rev_Reqt_Work_Form_FINAL; PUC_2018_Settlement_Filing_Requirements_Chp2_App; PUC_2018 Income Tax_PILs_Settlement_WF Tab T4 – FINAL

Supporting Parties: All

3.2 Revenue Requirement Settlement

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

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

Evidence:

Application: Exhibit 1 Section 2.1.5.1, Section 2.1.5.4, Section 2.1.5.6; Exhibit 2 Section 2.2.1.1 to 2.2.2.4; Exhibit 3 Section 2.3.3; Exhibit 4 Section 2.4.4, Section 2.4.5; Exhibit 5; Exhibit 6

IRRs: 1-STAFF-7, 1-CCC-2, 1-CCC-4, 1-CCC-8, 2-STAFF-8, 2-STAFF-10, 2-STAFF-11, 2-STAFF-13, 2-STAFF-17, 2-STAFF-22, 2-CCC-19, 2-CCC-29, 2-CCC-31, 2-CCC-41, 2-CCC-42, 2-VECC-10, 2-VECC-12, 3-STAFF-48, 3-VECC-28, 4-STAFF-50, 4-STAFF-57, 4-STAFF-58, 4-STAFF-59, 4-STAFF-60, 4-STAFF-61, 4-SEC-41, 4-VECC-32, 5-VECC-38

Appendices to this Settlement Proposal: None

Models: PUC_2018_Settlement_Rev_Reqt_Work_Form_FINAL; PUC_2018_Settlement_Filing_Requirements_Chp2_App

Supporting Parties: All

4.0 LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

4.1 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?

Complete Settlement: For the purposes of the settlement of all of the issues in this proceeding, PUC agrees to the following adjustment:

- PUC will adopt a revised load forecast of 628.9 GWh billed, calculated in accordance with the methodology set out in response to interrogatory VECC-47c, where the Purchased Power regression model is estimated using actual data for 2017 CDM historical data, and includes a trend variable.

Subject to the adjustment above, the Parties agree that the customer forecast, load forecast, loss factors, CDM adjustments and the resulting billing determinates are appropriate and are reflective of the energy and demand requirements of the applicant's customers. The adjusted load forecast is presented below as Table 7:

Table 7 – Load Forecast

Customer Class	Application	Interrogatories	Variance	Settlement	Variance
Residential					
Customers	29,789	29,816	27	29,816	-
kWh	296,393,596	287,663,507	(8,730,089)	288,323,799	660,292
General Service < 50 kW					
Customers	3,443	3,431	(12)	3,431	-
kWh	94,320,130	92,683,979	(1,636,151)	92,411,463	(272,516)
General Service 50 to 4,999 kW					
Customers	353	357	4	357	-
kWh	248,349,153	245,243,826	(3,105,327)	244,620,598	(623,228)
kW	624,500	616,309	(8,191)	614,743	(1,566)
Streetlights					
Connections	8,070	8,070	-	8,070	-
kWh	2,415,793	2,398,221	(17,572)	2,398,221	-
kW	7,076	7,030	(46)	7,030	-
Sentinel Lights					
Connections	348	354	6	354	-
kWh	218,403	209,800	(8,603)	209,800	-
kW	616	593	(23)	593	-
Unmetered Scattered Load					
Connections	23	22	(1)	22	-
kWh	1,176,822	944,731	(232,091)	944,731	-
Totals					
Customer/Connections	**42,026**	**42,050**	**24**	**42,050**	**-**
kWh	**642,873,897**	**629,144,064**	**(13,729,833)**	**628,908,612**	**(235,452)**
kW	**632,192**	**623,932**	**(8,260)**	**622,366**	**(1,566)**

A revised load forecast model in working Microsoft Excel format reflecting this Settlement Proposal is filed with this Settlement Proposal under file named 2018 PUC Load Forecast Model Settlement.

Table 8 below provides the kWh and kW values to be used as the threshold in LRAM Variance Account calculation from 2018 and onwards until the next rebasing cost of service rate application occurs. The values reflect the annualized impact of CDM programs implemented in 2017 and 2018.

Table 8 – 2018 Expected CDM Savings by Rate Class for LRAM Variance Account

2018 Expected CDM Savings by Rate Class for LRAM Variance Account				
Year	**Residential**	**General Service < 50 kW**	**General Service 50 to 4,999 kW**	**Total**
2018 Test - kWh	3,951,456	2,665,994	6,382,284	12,999,734
2018 Test - kW Annual			16,039	16,039
2018 Test - kW Monthly			1,337	1,337

Evidence:

Application: Exhibit 1 Section 2.1.5.3, Exhibit 3 Sections 2.3.1 to 2.3.2, Appendix 1 and Appendix 2, Exhibit 4 Section 2.4.6.1, Exhibit 7: Exhibit 8

IRRs: 1-CCC-5, 3-STAFF-44, 3-STAFF-45, 3-STAFF-46, 3-STAFF-49, 3-VECC-16, 3-VECC-17, 3-VECC-24, Pre-ADR VECC clarification questions 44, 45, 46, 47

Appendices to this Settlement Proposal: Appendix G

Models: 2018 PUC Load Forecast Model Settlement

Supporting Parties: All

4.2 Cost Allocation

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

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties agree that the cost allocation methodology is appropriate and results in revenue-to-cost ratios that are within the Board's permitted ranges. These revenue-to-cost ratios are reproduced below in Table 9.

Table 9 – Revenue-to-Cost Ratios

Customer Class	Cost Ratios 2018 Cost Allocation Model Line 75 Tab - O1	Proposed Revenue to Cost Ratio	Board Target Low	Board Target High
Residential	90.39%	92.62%	85.00%	115.00%
General Service < 50 kWh	116.08%	116.08%	80.00%	120.00%
General Service 50 to 4,999 kWh	111.07%	111.07%	80.00%	120.00%
Street Lights	274.47%	120.00%	70.00%	120.00%
Sentinel Lights	97.22%	97.22%	80.00%	120.00%
Unmetered Scattered Load	112.71%	112.71%	80.00%	120.00%

Evidence:

Application: Exhibit 1 Section 2.1.5.7; Exhibit 4 Section 2.4.3.2; Exhibit 7 including Appendix 1

IRRs: 7-STAFF-75, 7-VECC-40, 7-VECC-41

Appendices to this Settlement Proposal: None

Models: PUC_2018_Settlement_Cost _Allocation_Model - FINAL

Supporting Parties: All

4.3 Rate Design

Are the applicant's proposals for rate design appropriate?

Complete Settlement: For the purposes of settlement of the issues in this proceeding, PUC has agreed to set the fixed charges for the General Service 50 to 4,999 kW and USL rate classes, which are above the ceiling, at current levels. The difference will be made up through a corresponding increase in volumetric charges.

This results in a fixed rate of $114.46 for General Service 50 to 4,999 kW and $12.69 for USL, and a variable rate of $6.7259 per kW for General Service 50 4,999 kW and $0.0383 per kWh for USL.

Subject to the above, the Parties agree that PUC's proposals, including the proposed fixed/variable splits, for rate design are appropriate. The distribution charges resulting from this Settlement Proposal are produced below as Table 10.

Table 10: Distribution Charges

Customer Class	2017 Distribution Rates	2018 Distribution Rates Original Application	Adjustments	2018 Distribution Rates Settlement	2018 Fixed/Variable Split
Residential					
Monthly Service Charge	$16.79	$24.87	-$0.46	$24.41	77.80%
Distribution Volumetric per kWh	$0.0104	$0.0088	-$0.0002	$0.0086	22.20%
General Service < 50 kW					
Monthly Service Charge	$17.11	$21.04	-$0.31	$20.73	27.11%
Distribution Volumetric per kWh	$0.0205	$0.0252	-$0.0004	$0.0248	72.89%
General Service 50 to 4,999 kW					
Monthly Service Charge	$114.46	$140.76	-$26.30	$114.46	10.79%
Distribution Volumetric per kW	$5.4372	$6.6563	$0.0732	$6.7295	89.21%
Street Lights					
Monthly Service Charge	$2.94	$1.42	-$0.05	$1.37	67.87%
Distribution Volumetric per kW	$19.1736	$9.2724	-$0.3440	$8.9284	32.13%
Sentinel Lights					
Monthly Service Charge	$2.93	$3.60	-$0.05	$3.55	43.42%
Distribution Volumetric per kW	$27.3551	$33.6416	-$0.4914	$33.1502	56.58%
Unmetered Scattered Load					
Monthly Service Charge	$12.69	$15.06	-$2.37	$12.69	8.47%
Distribution Volumetric per kWh	$0.0310	$0.0368	$0.0015	$0.0383	91.53%

Evidence:

Application: Exhibit 1 Appendix 3; Exhibit 8 Sections 2.8 to 2.8.2, Appendix 2, Appendix 3

IRRs: 1-CCC-9, 8-STAFF-77

Appendices to this Settlement Proposal: None

Models: PUC_2018_Settlement_Rev_Reqt_Work_Form_FINAL (Tabs 12, 13)

Supporting Parties: All

4.4 Residential Rate Design

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

Complete Settlement: The Parties agree that the Applicant appropriately applied the OEB's policy on residential rate design. The rate impacts have been reproduced below as Table 11. The monthly fixed charge is proposed to increase by $7.62, of which, $3.48 is as a result of the residential rate design policy.

Table 11: Rate Impacts

Residential Rate Class	September 30, 2018 Rate	October 1, 2018 Rate	Difference $	Difference %
Monthly Service Charge	$16.79	$24.41	$7.62	45.38%
Distribution Volumetric Rate	$0.0104	$0.0086	-$0.0018	-17.31%

Evidence:

Application: Exhibit 1 Appendix 3; Exhibit 8 Sections 2.8 to 2.8.2, Appendix 2, Appendix 3

IRRs: 1-CCC-9

Appendices to this Settlement Proposal: None

Models: PUC_2018-Settlement_Tariff-Schedule-and-Bill-Impact-Model

Supporting Parties: All

4.5 Retail Transmission Service Rates

Are the proposed Retail Transmission Service Rates appropriate?

Complete Settlement: The Parties agree that the proposed Retail Transmission Service Rates are appropriate. Retail Transmission Service Rates have been reproduced below at Table 12 below.

Table12: Retail Transmission Service Rates

Customer Class	2017 RTSR Rates	2018 RTSR Rates Settlement
Residential		
Retail Transmission Rate - Network Service Rate per kWh	$0.0059	$0.0060
General Service < 50 kW		
Retail Transmission Rate - Network Service Rate per kWh	$0.0055	$0.0056
General Service 50 to 4,999 kW		
Retail Transmission Rate - Network Service Rate per kW	$2.2455	$2.2694
Retail Transmission Rate - Network Service Rate per kW - Interval Metered	$2.8240	$2.8541
Street Lights		
Retail Transmission Rate - Network Service Rate per kW	$1.6935	$1.7116
Sentinel Lights		
Retail Transmission Rate - Network Service Rate per kW	$1.7021	$1.7202
Unmetered Scattered Load		
Retail Transmission Rate - Network Service Rate per kWh	$0.0055	$0.0056

Evidence:

Application: Exhibit 8 Section 2.8.3 and Appendix 1

IRRs: 8-STAFF-78, 8-VECC-42

Appendices to this Settlement Proposal: None

Models: PUC_2018_Settlement_RTSR_Workform_FINAL

Supporting Parties: All

5.0 ACCOUNTING

5.1 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 Parties accept the evidence of PUC 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 2.1.3.10, 2.1.3.15, 2.1.5.2 and 2.1.8, Appendix 6, Appendix 7; Exhibit 2 Sections 2.2.1.1 and 2.2.2; Exhibit 3 Section 2.3.1.1; Exhibit 4 Sections 2.4.3.2, and 2.4.4, Appendix 11

IRRs: 4-STAFF-69, 4-SEC-41

Appendices to this Settlement Proposal: None

Models: None

Supporting Parties: All

5.2 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?

Complete Settlement: For the purposes of the settlement of all of the issues in this proceeding, the Parties agree to the following:

i) The current balance of $2.6 million in the deferral and variance accounts, including the $2.4 million in the Wholesale Market Service Charge variance account (Account 1580) is to be refunded to customers over a 19-month period ending April 30, 2020.

In addition, PUC will create a Rate Rider for Embedded Generation Adjustment for Account 1580 RSVA Wholesale Market Service Charge Account which returns to customers, on a per kWh basis, the amount collected for the Wholesale Market Service Charge and the Rural and Remote Electricity Rate Protection charge (RRRP) related to embedded generation, the calculation and purpose of which is further described at Appendix F. This credit will better align payment with the energy use, in that the credit is applied in the current year rather than refunded as a variance rate rider at a future time.

By way of background, due to embedded generation PUC was historically over-collecting the Wholesale Market Service Charge and the RRRP (which is set by the OEB) and then rebating these amounts to customers in the future. The Parties have agreed that, instead, PUC will create a forecast of average embedded generation over a calendar year. Based on the average annual embedded kWh generation, retail Wholesale Market Service Charge rates, and RRRP rates, PUC will determine an annual credit to be returned to all customers. Once the annual credit is determined, a per kWh credit rate will be determined based on the approved load forecast. Any under or over-forecasts on embedded generation in a given month would be booked to Account 1580 to ensure PUC is held whole regardless of any over or under-forecasted embedded generation. Table 11 at Appendix F sets out the embedded generation forecast for a 12-month period and the calculation of the per kWh rate rider applicable to all rate classes.

ii) Clearance of the debit balance in account 1508 (Other Regulatory Assets) and credit balance in account 2425 (Other Deferred Credits) associated with the Accounting Order set out in the PUC Settlement Agreement approved by the Board in its Decision in EB-2012-0162. Accounts 1508 and 2425 will be closed upon approval of this settlement agreement by the Board. Included in PUC's 2013 rates was an amount of $100,000 per year that was to be used to further PUC's productivity and efficiency. As per the Accounting Order, accounts 1508 and 2425 were utilized to record revenues and expenditures related to the productivity items.

For the purposes of the settlement of the issues in this proceeding, and subject to the above, the Parties accept PUC's evidence that its proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition and the continuation of existing accounts, are appropriate.

Finally, consistent with the OEB's letter dated July 20, 2018 to all rate-regulated licensed electricity distributors regarding the OEB's plan to standardize processes to improve accuracy of commodity pass-through variance accounts, the Parties agree that the Global Adjustment and other Group 1 account dispositions should be approved on an interim basis only, until such time as the OEB has finalized the new standardized requirements for regulatory accounting and RPP settlements.

Evidence:

Application: Exhibit 1 Section 2.1.5.8; Exhibit 9 in its entirety

IRRs: 1-SEC-5, 2-STAFF-26, 4-STAFF-65. 4-STAFF-67, 4-VECC-37, 9-STAFF-82, 9-STAFF-83, 9-STAFF-85, 9-STAFF-86, 9-STAFF-87, 9-STAFF-88, 9-STAFF-90, 9-STAFF-91, 9-VECC-43

Appendices to this Settlement Proposal: Appendix F

Models: None

Decision in EB-2012-0162, Appendix O

Supporting Parties: All

6.0 OTHER

6.1 Effective Date

Is the proposed effective date for 2018 rates appropriate?

Complete Settlement: Subject to the above, the Parties agree to an effective date of October 1, 2018, for 2018 rates.

Evidence:

Application: None.

IRRs: None.

Appendices to this Settlement Proposal: None.

Models: None.

Supporting Parties: All

APPENDIX A

PUC DISTRIBUTION INC.

SCHEDULE OF DRAFT TARIFFS

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date October 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0071

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a single family unit, non-commercial. This can be a separately metered living accommodation, town house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	24.41
Rate Rider for Tax Loss Carry-forward - effective until April 30, 2020	$	(1.30)
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) - effective until April 30, 2020	$	(0.05)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0086
Rate Rider for Disposition of Global Adjustment Account (2018) - Applicable only for Non-RPP Customers - effective until April 30, 2020	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - effective until April 30, 2020	$/kWh	(0.0032)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2020	$/kWh	0.0002
Rate Rider for Embedded Generation Adjustment - effective until	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0060

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	20.73
Rate Rider for Tax Loss Carry-forward - effective until April 30, 2020	$	(0.86)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0248
Rate Rider for Disposition of Global Adjustment Account (2018) - Applicable only for Non-RPP Customers - effective until April 30, 2020	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - effective until April 30, 2020	$/kWh	(0.0032)
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) - effective until April 30, 2020	$/kWh	(0.0001)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2020	$/kWh	0.0019
Rate Rider for Tax Loss Carry-forward - effective until April 30, 2020	$/kWh	(0.0010)
Rate Rider for Embedded Generation Adjustment - effective until	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0056

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly peak demand used for billing purposes over the past 12 months is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	114.46
Rate Rider for Tax Loss Carry-forward - effective until April 30, 2020	$	(4.74)
Distribution Volumetric Rate	$/kW	6.7295
Rate Rider for Disposition of Global Adjustment Account (2018) - Applicable only for Non-RPP Customers - approved on an interim basis effective until April 30, 2020	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - approved on an interim basis effective until April 30, 2020	$/kW	(1.2817)
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) - effective until April 30, 2020	$/kW	(0.0258)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2020	$/kW	0.0962
Rate Rider for Tax Loss Carry-forward - effective until April 30, 2020	$/kW	(0.2734)
Retail Transmission Rate - Network Service Rate	$/kW	2.2694
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.8541

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the Distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	12.69
Rate Rider for Tax Loss Carry-forward - effective until April 30, 2020	$	(0.53)
Distribution Volumetric Rate	$/kWh	0.0383
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - approved on an interim basis effective until April 30, 2020	$/kWh	(0.0032)
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) - effective until April 30, 2020	$/kWh	(0.0001)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2020	$/kWh	(0.0010)
Rate Rider for Tax Loss Carry-forward - effective until April 30, 2020	$/kWh	(0.0016)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0056

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential or General Service customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.55
Rate Rider for Tax Loss Carry-forward - effective until April 30, 2020	$	(0.15)
Distribution Volumetric Rate	$/kW	33.1502
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - approved on an interim basis effective until April 30, 2020	$/kW	(1.1433)
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) - effective until April 30, 2020	$/kW	(0.0229)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2020	$/kW	(1.1660)
Rate Rider for Tax Loss Carry-forward - effective until April 30, 2020	$/kW	(1.3742)
Retail Transmission Rate - Network Service Rate	$/kW	1.7202

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.37
Rate Rider for Tax Loss Carry-forward - effective until April 30, 2020	$	(0.06)
Distribution Volumetric Rate	$/kW	8.9284
Rate Rider for Disposition of Global Adjustment Account (2018) - Applicable only for Non-RPP Customers - approved on an interim basis effective until April 30, 2020	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts - Group 1 (2018) - approved on an interim basis effective until April 30, 2020	$/kW	(1.1380)
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 (2018) - effective until April 30, 2020	$/kW	(0.0221)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2020	$/kW	5.5286
Rate Rider for Tax Loss Carry-forward - effective until April 30, 2020	$/kW	(0.3701)
Retail Transmission Rate - Network Service Rate	$/kW	1.7116

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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Customer Administration

Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/reconnect charge - at meter - during regular hours	$	65.00
Disconnect/reconnect charge - at meter - after hours	$	185.00
Disconnect/reconnect charge - at pole - during regular hours	$	185.00
Disconnect/reconnect charge - at pole - after hours	$	415.00
Install/remove load control device - during regular hours	$	65.00
Install/remove load control device - after regular hours	$	185.00

Other

Special meter reads	$	30.00
Service call - customer-owned equipment		Time & Materials
Service call - after regular hours		Time & Materials
Temporary service - install & remove - overhead - no transformer		Time & Materials
Temporary service - install & remove - underground - no transformer		Time & Materials
Temporary service - install & remove - overhead - with transformer		Time & Materials
Specific charge for access to the power poles - $/pole/year	$	28.09
(with the exception of wireless attachments) - in effect until December 31, 2018		
Specific charge for access to the power poles - $/pole/year	$	43.63
(with the exception of wireless attachments) - in effect from January 1, 2019		
Removal of overhead lines - during regular hours		Time & Materials
Removal of overhead lines - after hours		Time & Materials
Roadway escort - after regular hours		Time & Materials

RETAIL SERVICE CHARGES (if applicable)

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0481
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0385

APPENDIX B

COMPARISON OF PUC DISTRIBUTION RATES (WITH TX) TO NORTHERN LDCS

Annual Bill		Residential				
kWh	700	Greater Sudbury	North Bay	Thunder Bay	Average	PUC Proposed Settlement
	Monthly	$288.84	$304.32	$266.76		$292.92
	Smart Meter	$6.84	$6.84	$6.84		$6.84
	Volumetric	$26.88	$31.08	$31.08		$72.24
	LV Rate	$1.68	$0.59	$0.00		$0.00
	LRAMVA	$0.00	$0.00	$0.00		$0.84
	Group 2 Rate Riders	$0.00	$0.00	$0.00		-$0.60
	WMS Rate Rider	$0.00	$0.00	$0.00		$0.00
	PILs Rate Rider	$0.00	$0.00	$0.00		$0.00
	Tx - Connection	$45.15	$59.81	$52.39		$0.00
	Tx - Network	$52.24	$59.81	$46.27		$52.82
	Total	**$421.63**	**$462.45**	**$403.34**	**$429.14**	**$425.06**
						99.05%

Annual Bill		General Service < 50 kW				
kWh	2000	Sudbury	North Bay	Thunder Bay	Average	PUC Proposed Settlement
	Monthly	$265.80	$291.48	$328.56		$248.76
	Smart Meter	$6.84	$6.84	$6.84		$6.84
	Volumetric	$458.40	$448.80	$427.20		$595.20
	LV Rate	$2.40	$1.68	$0.00		$0.00
	LRAMVA	$0.00	$0.00	$0.00		$43.20
	Group 2 Rate Riders	$0.00	$0.00	$0.00		-$2.40
	WMS Rate Rider	$0.00	$0.00	$0.00		$0.00
	PILs Rate Rider	$0.00	$0.00	$0.00		$0.00
	Tx - Connection	$91.07	$146.40	$117.60		$0.00
	Tx - Network	$111.30	$163.35	$142.19		$140.86
	Total	**$935.81**	**$1,058.55**	**$1,022.39**	**$1,005.58**	**$1,032.46**
						102.67%

Annual Bill		General Service > 50 kW				
kW	100	Greater Sudbury	North Bay	Thunder Bay	Average	PUC Proposed Settlement
	Monthly	$2,027.88	$3,681.48	$2,472.96		$1,373.52
	Smart Meter	$0.00	$0.00	$0.00		$0.00
	Volumetric	$5,268.84	$3,073.32	$4,020.60		$8,075.40
	LV Rate	$123.24	$30.60	$0.00		$0.00
	LRAMVA	$0.00	$0.00	$0.00		$104.04
	Group 2 Rate Riders	$0.00	$0.00	$0.00		-$30.96
	WMS Rate Rider	$0.00	$0.00	$0.00		$0.00
	PILs Rate Rider	$0.00	$0.00	$0.00		$0.00
	Tx - Connection	$3,489.08	$2,998.06	$2,564.03		$0.00
	Tx - Network	$4,155.50	$3,241.07	$2,968.40		$2,854.27
	Total	**$15,064.54**	**$13,024.52**	**$12,026.00**	**$13,371.69**	**$12,376.27**
						92.56%

APPENDIX C

REVENUE REQUIREMENT WORK FORM TRACKING SHEET

		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	$ 5,975,027	6.00%	$ 99,603,703	$ 91,810,703	$ 6,885,803	$ 3,783,956	$ 366,429	$ 11,886,833	$ 22,081,245	$ 2,389,661	$ 19,691,584	$ 3,679,687
Interrogatory	Update to 2017 Actuals	$ 6,002,217	6.00%	$ 100,056,955	$ 91,810,703	$ 6,885,803	$ 3,783,956	$ 335,246	$ 11,886,833	$ 22,077,252	$ 2,389,661	$ 19,687,591	$ 3,844,741
	Change	$ 27,190	0.00%	$ 453,252	$ -	$ 0	$ -	-$ 31,183	$ -	-$ 3,993	$ -	-$ 3,993	$ 165,054
Interrogatory	Update to Cost of Power	$ 5,992,760	6.00%	$ 99,899,321	$ 89,708,918	$ 6,728,169	$ 3,783,956	$ 333,200	$ 11,886,833	$ 22,065,750	$ 2,389,661	$ 19,676,089	$ 3,833,239
	Change	-$ 9,457	0.00%	-$ 157,634	-$ 2,101,785	-$ 157,634	$ -	-$ 2,046	$ -	-$ 11,502	$ -	-$ 11,502	-$ 11,502
Interrogatory	Update to Operating Revenue	$ 5,992,760	6.00%	$ 99,899,321	$ 89,708,918	$ 6,728,169	$ 3,783,956	$ 333,200	$ 11,886,833	$ 22,065,750	$ 2,800,114	$ 19,265,636	$ 3,422,786
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 410,453	-$ 410,453	-$ 410,453
Interrogatory	Update to Operating Expense	$ 5,993,155	6.00%	$ 99,905,906	$ 89,796,718	$ 6,734,754	$ 3,783,956	$ 333,286	$ 11,974,633	$ 22,154,030	$ 2,800,114	$ 19,353,916	$ 3,511,066
	Change	$ 395	0.00%	$ 6,585	$ 87,800	$ 6,585	$ -	$ 86	$ 87,800	$ 88,280	$ -	$ 88,280	$ 88,280
Settlement	Update to Other Revenue - Transfer Pricing	$ 5,993,155	6.00%	$ 99,905,906	$ 89,796,718	$ 6,734,754	$ 3,783,956	$ 333,286	$ 11,974,633	$ 22,154,030	$ 2,698,599	$ 19,455,431	$ 3,612,581
	Change	-$ 0	0.00%	$ 0	-$ 0	$ 0	$ -	$ 0	$ -	-$ 0	-$ 101,515	$ 101,515	$ 101,515
Settlement	Update to OM&A - Reduction of $500k	$ 5,990,906	6.00%	$ 99,868,406	$ 89,296,718	$ 6,697,254	$ 3,783,956	$ 332,799	$ 11,474,633	$ 21,651,294	$ 2,698,599	$ 18,952,694	$ 3,109,844
	Change	-$ 2,249	0.00%	-$ 37,500	-$ 500,000	-$ 37,500	$ -	-$ 487	-$ 500,000	-$ 502,736	$ -	-$ 502,737	-$ 502,737
Settlement	Update to Capital Assets - Moving Sub 16 to WIP	$ 5,978,412	6.00%	$ 99,660,130	$ 89,296,718	$ 6,697,254	$ 3,780,329	$ 334,848	$ 11,474,633	$ 21,637,222	$ 2,698,599	$ 18,938,622	$ 3,095,772
	Change	-$ 12,494	0.00%	-$ 208,276	$ -	$ -	-$ 3,627	$ 2,049	$ -	-$ 14,072	$ -	-$ 14,072	-$ 14,072
Settlement	Update to Remove PILs Carryforward in RRWF	$ 5,978,412	6.00%	$ 99,660,130	$ 89,296,718	$ 6,697,254	$ 3,780,329	$ 586,742	$ 11,474,633	$ 21,889,116	$ 2,698,599	$ 19,190,517	$ 3,347,667
	Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ 251,894	$ -	$ 251,894	$ -	$ 251,895	$ 251,895
Settlement	Update to Load Forecast - 628.9 GWh	$ 5,978,287	6.00%	$ 99,658,055	$ 89,269,059	$ 6,695,179	$ 3,780,329	$ 586,715	$ 11,474,633	$ 21,888,965	$ 2,698,599	$ 19,190,365	$ 3,354,750
	Change	-$ 125	0.00%	-$ 2,075	-$ 27,659	-$ 2,075	$ -	-$ 27	$ -	-$ 151	$ -	-$ 152	$ 7,083

APPENDIX D

CHAPTER 2 APPENDICES APPENDIX 2-BA

FINAL FIXED ASSET CONTINUITY SCHEDULE REFLECTING SETTLEMENT

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**
N/A	1706	Land Rights	$ 602,307			$ 602,307	$ -			$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,340			$ 1,604,340	-$ 156,520	-$ 39,130		-$ 195,650	$ 1,408,690
47	1730	Overhead Conductors & Devices	$ 63,894			$ 63,894	-$ 7,988	-$ 1,997		-$ 9,985	$ 53,909
47	1735	Underground Conduit	$ 870,021			$ 870,021	-$ 99,432	-$ 24,858		-$ 124,290	$ 745,731
47	1740	Underground Conductors & Devices	$ 215,252			$ 215,252	-$ 39,136	-$ 9,784		-$ 48,920	$ 166,332
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 89,160			$ 89,160	$ -			$ -	$ 89,160
CEC	1806	Land Rights	$ 178,951	$ 1,621		$ 180,572				$ -	$ 180,572
47	1808	Buildings	$ 25,027,092	$ 63,099		$ 25,090,191	-$ 2,717,414	-$ 683,596		-$ 3,401,010	$ 21,689,181
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 7,662,606	$ 122,779		$ 7,785,385	-$ 1,000,670	-$ 266,269		-$ 1,266,939	$ 6,518,446
47	1820	Distribution Station Equipment <50 kV	$ 10,510,642	$ 404,970		$ 10,915,612	-$ 1,597,764	-$ 435,782		-$ 2,033,546	$ 8,882,066
47	1825	Storage Battery Equipment	$ 13,722			$ 13,722	-$ 2,612	-$ 653		-$ 3,265	$ 10,457
47	1830	Poles, Towers & Fixtures	$ 17,808,104	$ 1,586,992		$ 19,395,096	-$ 1,301,616	-$ 413,255		-$ 1,714,871	$ 17,680,225
47	1835	Overhead Conductors & Devices	$ 12,985,478	$ 1,003,237		$ 13,988,715	-$ 1,073,637	-$ 311,231		-$ 1,384,868	$ 12,603,847
47	1840	Underground Conduit	$ 3,662,059	$ 214,630		$ 3,876,689	-$ 897,888	-$ 239,532		-$ 1,137,420	$ 2,739,269
47	1845	Underground Conductors & Devices	$ 13,447,277	$ 352,285		$ 13,799,562	-$ 2,105,522	-$ 553,859		-$ 2,659,381	$ 11,140,181
47	1850	Line Transformers	$ 13,256,634	$ 1,005,278		$ 14,261,912	-$ 1,130,181	-$ 351,146		-$ 1,481,327	$ 12,780,585
47	1855	Services (Overhead & Underground)	$ 6,076,632	$ 457,483		$ 6,534,115	-$ 583,072	-$ 171,479		-$ 754,551	$ 5,779,564
47	1860	Meters	$ 4,838,567	$ 146,036		$ 4,984,603	-$ 1,678,254	-$ 443,908		-$ 2,122,162	$ 2,862,441
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
12	1925	Compute rSoftware	$ -			$ -				$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,600,674	$ 29,766		$ 1,630,440	-$ 952,647	-$ 241,432		-$ 1,194,079	$ 436,361
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,740	$ -		-$ 11,161,740	$ 1,313,144	$ 328,286		$ 1,641,430	-$ 9,520,310
47	2440	Deferred Revenue[5]	-$ 3,087,531	-$ 450,000		-$ 3,537,531	$ 151,022	$ 79,297		$ 230,319	-$ 3,307,212
						$ -				$ -	$ -
		Sub-Total	**$ 106,264,141**	**$ 4,938,176**	**$ -**	**$ 111,202,317**	**-$ 13,880,187**	**-$ 3,780,328**	**$ -**	**-$ 17,660,515**	**$ 93,541,802**
	2055	**Work in Progress**	$ 37,675	$ 420,179		$ 457,854				$ -	$ 457,854
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
		Total PP&E	**$ 106,301,816**	**$ 5,358,355**	**$ -**	**$ 111,660,171**	**-$ 13,880,187**	**-$ 3,780,328**	**$ -**	**-$ 17,660,515**	**$ 93,999,656**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,780,328**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 3,780,328

APPENDIX E

RATE RIDER FOR TAX LOSS CARRY-FORWARD

The Parties have agreed that PUC will implement a new standalone Rate Rider, as follows:

- Rate Rider to credit customers the full benefits of grossed-up tax loss carry-forward amounts of $3,493,253 over a 19-month period ending April 30, 2020, offsetting PILs that are otherwise included in rates for the duration of the 19-month period. The effect of this rate rider is that the loss carry-forward amount of $3,493,253 is to be effectively removed from the Revenue Requirement and PILs balances and the Total Amount to be refunded (as calculated and set out in the Table 10 below) is to be allocated to rate classes based on the approved test year distribution revenue using both a fixed and volumetric billing determinant for the 19-month period.

The Table below illustrates the calculation of the rate rider.

Table 10 – Calculation of Total Amount to be refunded

Calculation of PILS Rate Rider

PILs credit to customers

Total Loss Carry Forward	$3,493,253
Rate	26.50%
Reduction in tax payable	$925,712
Benefit to customers (grossed up)	$1,259,472

Allocation to Customer Classes (from revenue requirement)

		Base Revenue	Class %	Class PILs Credit
Residential		$11,226,807	58.50%	($736,820)
General Service Less than 50 kW		$3,149,458	16.41%	($206,700)
General Service 50 to 4,999 kW		$4,544,464	23.68%	($298,255)
Unmetered Scattered Load		$39,551	0.21%	($2,596)
Sentinel Lighting		$34,742	0.18%	($2,280)
Street Lighting		$195,345	1.02%	($12,821)
		$19,190,366	100.00%	($1,259,472)

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Calculation of Customer Class Rate Rider

These rate riders are to be in effect for 19 months commencing October 1, 2018 (up to and including April 30, 2020). The residential class credit is a fixed monthly while the remainder of the rate classes will have both a fixed monthly credit and a volumetric credit as per the table below.

Rate Rider Recovery Period (in months) **19**

Rate Class (Enter Rate Classes in cells below)	Units	# Cust	Annual kWh	annual kW	kWh 19 months	kW 19 months	Allocated PILs Credit	Fixed %	Var %	Total	Fixed $	Var $	Fixed + Var	Fixed Rate Rider for PILs	Var Rate Rider for PILs Credit
RESIDENTIAL	kWh	29,816	288,323,799		456,511,721		($736,820)	100%	0%	100%	($736,819.89)	$0	($736,820)	($1.30)	**$0.0000**
GENERAL SERVICE LESS THAN 50 KW	kWh	3,431	92,411,463		146,317,842		($206,700)	27.1%	72.9%	100%	($56,089.31)	($150,611)	($206,700)	($0.86)	**($0.0010)**
GENERAL SERVICE 50 TO 4,999 KW	kW	357	244,620,598	614,743	387,315,132	973,341	($298,255)	10.8%	89.2%	100%	($32,181.68)	($266,073)	($298,255)	($4.74)	**($0.2734)**
UNMETERED SCATTERED LOAD	kWh	22	944,731		1,495,822		($2,596)	8.5%	91.5%	100%	($219.97)	($2,376)	($2,596)	($0.53)	**($0.0016)**
SENTINEL LIGHTING	kW	354	209,800	593	332,183	939	($2,280)	43.4%	56.6%	100%	($989.82)	($1,290)	($2,280)	($0.15)	**($1.3742)**
STREET LIGHTING	kW	8,070	2,398,221	7,030	3,797,176	11,131	($12,821)	67.9%	32.1%	100%	($8,701.07)	($4,119)	($12,821)	($0.06)	**($0.3701)**
		42,050	628,908,614	622,366	995,769,876	985,411	(1,259,472)				($835,002)	($424,470)	($1,259,472)		

APPENDIX F

RATE RIDER FOR EMBEDDED GENERATION ADJUSTMENT

The Parties have agreed that PUC will implement a new standalone Rate Rider, as follows:

As can be seen in the chart below, commencing in 2011 PUC connected a large amount of embedded generation to its distribution system. The embedded generation is mostly the result of two large solar farms which were operational for a full year commencing in 2012. Due to this embedded generation PUC has historically over-collected the Wholesale Market Service Charge (which is set by the OEB) and then rebated these amounts to customers in the future. The Parties have agreed that, going forward, PUC will implement a rate rider credit that will serve to return a reasonable forecast of the over-collection of Wholesale Market Service Charges, and Rural and Remote Electricity Rate Protection charges (RRRP) to customers in a proactive manner. PUC has determined a forecast of average expected embedded generation over a calendar year. Based on this average annual embedded kWh generation, retail Wholesale Market Service Charge rates and RRRP rates, PUC has determined an annual credit to be returned to all customers. Once the annual credit is determined, a per kWh credit rate will be determined based on the approved kWh load forecast.

Any under or over-forecasts on embedded generation in a given month will be booked to Account 1580 to ensure PUC is held whole regardless of any over or under-forecasted embedded generation. That is to say, in all instances PUC will be held whole for all WMSC and RRRP as if this rate rider did not exist. The table below sets out the embedded generation forecast for a 12-month period and the calculation of the per kWh rate rider applicable to all rate classes.

In IRR 9-Staff-83, PUC indicated that the large balance in Account 1580 - RSVA - Wholesale Market Service charge is attributable to two main factors, embedded generation and Transmission Rights Clearing Account Credits. The Transmission Rights Clearing Account Credits are a provincial issue and it is unknown to PUC if the Transmission Rights Clearing Account Credits will continue. PUC, therefore, has estimated the Whole Market Service Charge credit based on the average embedded generation from 2012 (first full year of solar farms generation) to 2017.

Table 11 – Average Embedded Generation Forecast for 12-Month Period

Year	Embedded Generation
2010	2,018,204
2011	38,285,285
2012	78,154,102
2013	70,733,589
2014	67,412,356
2015	76,318,882
2016	68,431,934
2017	74,074,630

Average 2012 to 2017 72,520,916

Calculation of WMS credit to customers

Embedded kWh	72,520,915.5
WMS + RRRP	-$0.0035
WMS credit to customers	-$253,823

The rate rider has been set to credit customers for the estimated amount of $253,823 on an annual basis.

Please indicate the Rate Rider Recovery Period (in years) 1

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	Actual Credit due to Rounding
RESIDENTIAL	kWh	288,323,799	($116,365.51)	**($0.0004)**	($115,329.52)
GENERAL SERVICE LESS THAN 50 KW	kWh	92,411,463	($37,296.63)	**($0.0004)**	($36,964.59)
GENERAL SERVICE 50 TO 4,999 KW	kWh	244,620,598	($98,727.20)	**($0.0004)**	($97,848.24)
UNMETERED SCATTERED LOAD	kWh	944,731	($381.29)	**($0.0004)**	($377.89)
SENTINEL LIGHTING	kWh	209,800	($84.67)	**($0.0004)**	($83.92)
STREET LIGHTING	kWh	2,398,221	($967.91)	**($0.0004)**	($959.29)
		628,908,614	($253,823.20)		($251,563.45)

APPENDIX G

BILL IMPACTS

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0489
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 16.79	1	$ 16.79	$ 24.41	1	$ 24.41	$ 7.62	45.38%
Distribution Volumetric Rate	$ 0.0104	750	$ 7.80	$ 0.0086	750	$ 6.45	$ (1.35)	-17.31%
Fixed Rate Riders	$ -	1	$ -	$ (1.35)	1	$ (1.35)	$ (1.35)	
Volumetric Rate Riders	$ -	750	$ -	$ 0.0002	750	$ 0.15	$ 0.15	
Sub-Total A (excluding pass through)			**$ 24.59**			**$ 29.66**	**$ 5.07**	**20.62%**
Line Losses on Cost of Power	$ 0.0820	37	$ 3.01	$ 0.0820	36	$ 2.96	$ (0.05)	-1.64%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	-$ 0.0032	750	$ (2.40)	$ (2.40)	
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		750	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	-$ 0.0004	750	$ (0.30)	$ (0.30)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 28.17**			**$ 30.49**	**$ 2.32**	**8.24%**
RTSR - Network	$ 0.0059	787	$ 4.64	$ 0.0060	786	$ 4.72	$ 0.08	1.62%
RTSR - Connection and/or Line and Transformation Connection	$ -	787	$ -	$ -	786	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 32.81**			**$ 35.20**	**$ 2.40**	**7.30%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	787	$ 2.83	$ 0.0036	786	$ 2.83	$ (0.00)	-0.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	787	$ 0.24	$ 0.0003	786	$ 0.24	$ (0.00)	-0.08%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	488	$ 31.69	$ 0.0650	488	$ 31.69	$ -	0.00%
TOU - Mid Peak	$ 0.0940	128	$ 11.99	$ 0.0940	128	$ 11.99	$ -	0.00%
TOU - On Peak	$ 0.1320	135	$ 17.82	$ 0.1320	135	$ 17.82	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 97.62**			**$ 100.01**	**$ 2.39**	**2.45%**
HST	13%		$ 12.69	13%		$ 13.00	$ 0.31	2.45%
8% Rebate	8%		$ (7.81)	8%		$ (8.00)	$ (0.19)	
Total Bill on TOU			**$ 102.50**			**$ 105.01**	**$ 2.51**	**2.45%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	308	kWh
Demand	-	kW
Current Loss Factor	1.0489	
Proposed/Approved Loss Factor	1.0481	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 16.79	1	$ 16.79	$ 24.41	1	$ 24.41	$ 7.62	45.38%
Distribution Volumetric Rate	$ 0.0104	308	$ 3.20	$ 0.0086	308	$ 2.65	$ (0.55)	-17.31%
Fixed Rate Riders	$ -	1	$ -	$ (1.35)	1	$ (1.35)	$ (1.35)	
Volumetric Rate Riders	$ -	308	$ -	$ 0.0002	308	$ 0.06	$ 0.06	
Sub-Total A (excluding pass through)			**$ 19.99**			**$ 25.77**	**$ 5.78**	**28.90%**
Line Losses on Cost of Power	$ 0.0820	15	$ 1.23	$ 0.0820	15	$ 1.21	$ (0.02)	-1.64%
Total Deferral/Variance Account Rate Riders	$ -	308	$ -	-$ 0.0032	308	$ (0.99)	$ (0.99)	
CBR Class B Rate Riders	$ -	308	$ -	$ -	308	$ -	$ -	
GA Rate Riders	$ -	308	$ -	$ -	308	$ -	$ -	
Low Voltage Service Charge	$ -	308	$ -		308	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		308	$ -	-$ 0.0004	308	$ (0.12)	$ (0.12)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 21.80**			**$ 26.45**	**$ 4.65**	**21.32%**
RTSR - Network	$ 0.0059	323	$ 1.91	$ 0.0060	323	$ 1.94	$ 0.03	1.62%
RTSR - Connection and/or Line and Transformation Connection	$ -	323	$ -	$ -	323	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 23.70**			**$ 28.38**	**$ 4.68**	**19.74%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	323	$ 1.16	$ 0.0036	323	$ 1.16	$ (0.00)	-0.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	323	$ 0.10	$ 0.0003	323	$ 0.10	$ (0.00)	-0.08%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	200	$ 13.01	$ 0.0650	200	$ 13.01	$ -	0.00%
TOU - Mid Peak	$ 0.0940	52	$ 4.92	$ 0.0940	52	$ 4.92	$ -	0.00%
TOU - On Peak	$ 0.1320	55	$ 7.32	$ 0.1320	55	$ 7.32	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 50.47**			**$ 55.15**	**$ 4.68**	**9.27%**
HST	13%		$ 6.56	13%		$ 7.17	$ 0.61	9.27%
8% Rebate	8%		$ (4.04)	8%		$ (4.41)	$ (0.37)	
Total Bill on TOU			**$ 52.99**			**$ 57.90**	**$ 4.91**	**9.27%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0489
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 17.11	1	$ 17.11	$ 20.73	1	$ 20.73	$ 3.62	21.16%
Distribution Volumetric Rate	$ 0.0205	2000	$ 41.00	$ 0.0248	2000	$ 49.60	$ 8.60	20.98%
Fixed Rate Riders	$ -	1	$ -	$ (0.86)	1	$ (0.86)	$ (0.86)	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0008	2000	$ 1.60	$ 1.60	
Sub-Total A (excluding pass through)			**$ 58.11**			**$ 71.07**	**$ 12.96**	**22.30%**
Line Losses on Cost of Power	$ 0.0820	98	$ 8.02	$ 0.0820	96	$ 7.89	$ (0.13)	-1.64%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	-$ 0.0032	2,000	$ (6.40)	$ (6.40)	
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	-$ 0.0004	2,000	$ (0.80)	$ (0.80)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 66.70**			**$ 72.33**	**$ 5.63**	**8.44%**
RTSR - Network	$ 0.0055	2,098	$ 11.54	$ 0.0056	2,096	$ 11.74	$ 0.20	1.74%
RTSR - Connection and/or Line and Transformation Connection	$ -	2,098	$ -	$ -	2,096	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 78.24**			**$ 84.07**	**$ 5.83**	**7.45%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	2,098	$ 7.55	$ 0.0036	2,096	$ 7.55	$ (0.01)	-0.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	2,098	$ 0.63	$ 0.0003	2,096	$ 0.63	$ (0.00)	-0.08%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0650	1,300	$ 84.50	$ 0.0650	1,300	$ 84.50	$ -	0.00%
TOU - Mid Peak	$ 0.0940	340	$ 31.96	$ 0.0940	340	$ 31.96	$ -	0.00%
TOU - On Peak	$ 0.1320	360	$ 47.52	$ 0.1320	360	$ 47.52	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 250.65**			**$ 256.47**	**$ 5.82**	**2.32%**
HST	13%		$ 32.58	13%		$ 33.34	$ 0.76	2.32%
8% Rebate	8%		$ (20.05)	8%		$ (20.52)	$ (0.47)	
Total Bill on TOU			**$ 263.18**			**$ 269.29**	**$ 6.11**	**2.32%**

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**57,220** kWh
Demand	**145** kW
Current Loss Factor	**1.0489**
Proposed/Approved Loss Factor	**1.0481**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 114.46	1	$ 114.46	$ 114.46	1	$ 114.46	$ -	0.00%
Distribution Volumetric Rate	$ 5.4372	145	$ 788.39	$ 6.7295	145	$ 975.78	$ 187.38	23.77%
Fixed Rate Riders	$ -	1	$ -	$ (4.74)	1	$ (4.74)	$ (4.74)	
Volumetric Rate Riders	$ -	145	$ -	-$ 0.2030	145	$ (29.44)	$ (29.44)	
Sub-Total A (excluding pass through)			**$ 902.85**			**$ 1,056.06**	**$ 153.21**	**16.97%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	145	$ -	-$ 1.2817	145	$ (185.85)	$ (185.85)	
CBR Class B Rate Riders	$ -	145	$ -	$ -	145	$ -	$ -	
GA Rate Riders	$ -	57,220	$ -	$ 0.0004	57,220	$ 22.89	$ 22.89	
Low Voltage Service Charge	$ -	145	$ -		145	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		145	$ -	-$ 0.0004	145	$ (0.06)	$ (0.06)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 902.85**			**$ 893.05**	**$ (9.81)**	**-1.09%**
RTSR - Network	$ 2.2455	145	$ 325.60	$ 2.2694	145	$ 329.06	$ 3.47	1.06%
RTSR - Connection and/or Line and Transformation Connection	$ -	145	$ -	$ -	145	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,228.45**			**$ 1,222.11**	**$ (6.34)**	**-0.52%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	60,018	$ 216.07	$ 0.0036	59,972	$ 215.90	$ (0.16)	-0.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	60,018	$ 18.01	$ 0.0003	59,972	$ 17.99	$ (0.01)	-0.08%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	60,018	$ 6,607.99	$ 0.1101	59,972	$ 6,602.95	$ (5.04)	-0.08%
Total Bill on Average IESO Wholesale Market Price			**$ 8,070.76**			**$ 8,059.20**	**$ (11.56)**	**-0.14%**
HST	13%		$ 1,049.20	13%		$ 1,047.70	$ (1.50)	-0.14%
Total Bill on Average IESO Wholesale Market Price			**$ 9,119.96**			**$ 9,106.90**	**$ (13.06)**	**-0.14%**

Customer Class:	**UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**3,600**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0489**	
Proposed/Approved Loss Factor	**1.0481**	

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 12.69**	1	$ 12.69	**$ 12.69**	1	$ 12.69	$ -	0.00%
Distribution Volumetric Rate	**$ 0.0310**	3600	$ 111.60	**$ 0.0383**	3600	$ 137.88	$ 26.28	23.55%
Fixed Rate Riders	**$ -**	1	$ -	**$ (0.53)**	1	$ (0.53)	$ (0.53)	
Volumetric Rate Riders	**$ -**	3600	$ -	**-$ 0.0027**	3600	$ (9.72)	$ (9.72)	
Sub-Total A (excluding pass through)			**$ 124.29**			**$ 140.32**	**$ 16.03**	**12.90%**
Line Losses on Cost of Power	**$ 0.1101**	176	$ 19.38	**$ 0.1101**	173	$ 19.06	$ (0.32)	-1.64%
Total Deferral/Variance Account Rate Riders	**$ -**	3,600	$ -	**-$ 0.0032**	3,600	$ (11.52)	$ (11.52)	
CBR Class B Rate Riders	**$ -**	3,600	$ -	**$ -**	3,600	$ -	$ -	
GA Rate Riders	**$ -**	3,600	$ -	**$ -**	3,600	$ -	$ -	
Low Voltage Service Charge	**$ -**	3,600	$ -		3,600	$ -	$ -	
Smart Meter Entity Charge (if applicable)	**$ -**	1	$ -	**$ -**	1	$ -	$ -	
Additional Fixed Rate Riders	**$ -**	1	$ -	**$ -**	1	$ -	$ -	
Additional Volumetric Rate Riders		3,600	$ -	**-$ 0.0004**	3,600	$ (1.44)	$ (1.44)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 143.67**			**$ 146.42**	**$ 2.75**	**1.92%**
RTSR - Network	**$ 0.0055**	3,776	$ 20.77	**$ 0.0056**	3,773	$ 21.13	$ 0.36	1.74%
RTSR - Connection and/or Line and Transformation Connection	**$ -**	3,776	$ -	**$ -**	3,773	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 164.44**			**$ 167.55**	**$ 3.11**	**1.89%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	3,776	$ 13.59	**$ 0.0036**	3,773	$ 13.58	$ (0.01)	-0.08%
Rural and Remote Rate Protection (RRRP)	**$ 0.0003**	3,776	$ 1.13	**$ 0.0003**	3,773	$ 1.13	$ (0.00)	-0.08%
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	**$ 0.25**	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	**$ 0.1101**	3,600	$ 396.36	**$ 0.1101**	3,600	$ 396.36	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 575.78**			**$ 578.88**	**$ 3.10**	**0.54%**
HST	13%		$ 74.85	13%		$ 75.25	$ 0.40	0.54%
Total Bill on Average IESO Wholesale Market Price			**$ 650.63**			**$ 654.13**	**$ 3.51**	**0.54%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	50 kWh
Demand	1 kW
Current Loss Factor	1.0489
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2.93	1	$ 2.93	$ 3.55	1	$ 3.55	$ 0.62	21.16%
Distribution Volumetric Rate	$ 27.3551	1	$ 27.36	$ 33.1502	1	$ 33.15	$ 5.80	21.18%
Fixed Rate Riders	$ -	1	$ -	$ (0.15)	1	$ (0.15)	$ (0.15)	
Volumetric Rate Riders	$ -	1	$ -	-$ 2.5631	1	$ (2.56)	$ (2.56)	
Sub-Total A (excluding pass through)			**$ 30.29**			**$ 33.99**	**$ 3.70**	**12.22%**
Line Losses on Cost of Power	$ 0.1101	2	$ 0.27	$ 0.1101	2	$ 0.26	$ (0.00)	-1.64%
Total Deferral/Variance Account Rate Riders	$ -	1	$ -	-$ 1.1433	1	$ (1.14)	$ (1.14)	
CBR Class B Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
GA Rate Riders	$ -	50	$ -	$ -	50	$ -	$ -	
Low Voltage Service Charge	$ -	1	$ -		1	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		1	$ -	-$ 0.0004	1	$ (0.00)	$ (0.00)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 30.55**			**$ 33.11**	**$ 2.55**	**8.36%**
RTSR - Network	$ 1.7021	1	$ 1.70	$ 1.7202	1	$ 1.72	$ 0.02	1.06%
RTSR - Connection and/or Line and Transformation Connection	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 32.26**			**$ 34.83**	**$ 2.57**	**7.97%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	52	$ 0.19	$ 0.0036	52	$ 0.19	$ (0.00)	-0.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	52	$ 0.02	$ 0.0003	52	$ 0.02	$ (0.00)	-0.08%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	50	$ 5.51	$ 0.1101	50	$ 5.51	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 38.22**			**$ 40.79**	**$ 2.57**	**6.73%**
HST	13%		$ 4.97	13%		$ 5.30	$ 0.33	6.73%
Total Bill on Average IESO Wholesale Market Price			**$ 43.18**			**$ 46.09**	**$ 2.91**	**6.73%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	199,852 kWh
Demand	585 kW
Current Loss Factor	1.0489
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2.94	8070	$ 23,725.80	$ 1.37	8070	$ 11,055.90	$ (12,669.90)	-53.40%
Distribution Volumetric Rate	$ 19.1736	585	$ 11,216.56	$ 8.9284	585	$ 5,223.11	$ (5,993.44)	-53.43%
Fixed Rate Riders	$ -	1	$ -	$ (0.06)	1	$ (0.06)	$ (0.06)	
Volumetric Rate Riders	$ -	585	$ -	$ 5.1364	585	$ 3,004.79	$ 3,004.79	
Sub-Total A (excluding pass through)			**$ 34,942.36**			**$ 19,283.75**	**$ (15,658.61)**	**-44.81%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	585	$ -	-$ 1.1380	585	$ (665.73)	$ (665.73)	
CBR Class B Rate Riders	$ -	585	$ -	$ -	585	$ -	$ -	
GA Rate Riders	$ -	199,852	$ -	$ 0.0004	199,852	$ 79.94	$ 79.94	
Low Voltage Service Charge	$ -	585	$ -		585	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		585	$ -	-$ 0.0004	585	$ (0.23)	$ (0.23)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 34,942.36**			**$ 18,697.72**	**$ (16,244.63)**	**-46.49%**
RTSR - Network	$ 1.6935	585	$ 990.70	$ 1.7116	585	$ 1,001.29	$ 10.59	1.07%
RTSR - Connection and/or Line and Transformation Connection	$ -	585	$ -	$ -	585	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 35,933.05**			**$ 19,699.01**	**$ (16,234.04)**	**-45.18%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	209,625	$ 754.65	$ 0.0036	209,465	$ 754.07	$ (0.58)	-0.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	209,625	$ 62.89	$ 0.0003	209,465	$ 62.84	$ (0.05)	-0.08%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	209,625	$ 23,079.69	$ 0.1101	209,465	$ 23,062.08	$ (17.60)	-0.08%
Total Bill on Average IESO Wholesale Market Price			**$ 59,830.53**			**$ 43,578.26**	**$ (16,252.27)**	**-27.16%**
HST	13%		$ 7,777.97	13%		$ 5,665.17	$ (2,112.79)	-27.16%
Total Bill on Average IESO Wholesale Market Price			**$ 67,608.49**			**$ 49,243.43**	**$ (18,365.06)**	**-27.16%**

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