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

DECISION AND RATE ORDER

EB-2022-0059

PUC DISTRIBUTION INC.

Application for electricity distribution rates beginning May 1, 2023

BEFORE: Pankaj Sardana
Presiding Commissioner

Emad Elsayed
Commissioner

Robert Dodds
Commissioner

April 6, 2023

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

TABLE OF CONTENTS

1 OVERVIEW

PUC Distribution provides electricity distribution services to approximately 33,865 residential, commercial, and industrial customers in most of the City of Sault Ste. Marie as well as parts of Prince Township, Dennis Township and the Rankin Reserve.

PUC Distribution applied for approval of its proposed electricity distribution rates for five years, using the Price Cap Incentive rate-setting option. With an approved 2023 test year, PUC Distribution would be able apply to have its rates adjusted mechanistically in each of the years 2024-2027, based on inflation and the OEB's assessment of PUC Distribution's efficiency.

On March 10, 2023, PUC Distribution filed a settlement proposal with a full settlement agreed to by PUC Distribution and the Parties, and supported by OEB staff. The Parties include PUC Distribution and the approved intervenors.

For the reasons provided in this Decision and Rate Order, the OEB approves the settlement proposal filed by PUC Distribution on March 10, 2023. The OEB finds that implementation of the settlement proposal will result in reasonable outcomes for both PUC Distribution and its customers.

PUC Distribution's application was unique in that, in addition to PUC Distribution's on-going Operations, Maintenance & Administration and capital needs, the revenue requirement and rate impacts arising from the utility's large and innovative Sault Smart Grid (SSG) project had to be carefully considered. The OEB commends the Parties for formulating and settling an SSG project recovery mechanism that should mitigate potential adverse financial impacts to PUC Distribution while minimizing rate impacts to PUC Distribution's customers.

As a result of this Decision and Rate Order, it is estimated that for a typical residential customer with a monthly consumption of 750 kWh, the total bill impact will be an increase of $4.25 per month before taxes and the Ontario Electricity Rebate, or 3.55%. These bill impacts do not reflect anticipated energy savings of 2.70% that may be achieved through the implementation of the SSG project. PUC Distribution anticipates being able to start measuring savings at the time of Substantial Completion of the project, which is anticipated to be November 1, 2023. If 2.70% energy savings are achieved at the time of Substantial Completion, it is estimated that for a typical residential customer with a monthly consumption of 750 kWh, the total bill impact would be reduced to an increase of $2.08 per month before taxes and the Ontario Electricity Rebate, or 1.73% compared to current rates, all else being equal.

2 CONTEXT AND PROCESS

The OEB's *Renewed Regulatory Framework for Electricity*[1] and *Handbook for Utility Rate Applications*[2] provide distributors with performance-based rate application options that support the cost-effective planning and efficient operation of a distribution network. This framework provides an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

PUC Distribution filed an application on August 31, 2022 for 2023 rates under the Price-Cap Incentive rate-setting option of the *Renewed Regulatory Framework for Electricity*.[3] The application was accepted by the OEB as complete on September 14, 2022. The OEB issued a Notice of Hearing on September 23, 2022, inviting parties to apply for intervenor status. Consumers Council of Canada (CCC), Environmental Defence, School Energy Coalition (SEC), and the Vulnerable Energy Consumers Coalition (VECC) were granted intervenor status and cost award eligibility. OEB staff also participated in this proceeding.

The OEB received one letter of comment, which was placed on the record of this proceeding. These comments were taken into consideration during the evaluation of the application by the OEB.

The OEB issued Procedural Order No. 1 on October 18, 2022. This order established, among other things, the timetable for a written interrogatory discovery process and a settlement conference.

The OEB issued its approved Issues List on October 27, 2022. PUC Distribution responded to the interrogatories and follow-up questions submitted by OEB staff and the intervenors.

A settlement conference took place from December 12-14, 2022, and continued on December 16 and 20, 2022. PUC Distribution and the following intervenors participated

[1] *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012
[2] *Handbook for Utility Rate Applications*, October 13, 2016
[3] Under section 78 of the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15, Schedule B, a distributor must apply to the OEB to change the rates it charges its customers.

in the settlement conference: CCC, Environmental Defence, SEC, and VECC. OEB staff also attended the conference but was not a party to the settlement.

On January 23, 2023, PUC Distribution filed a request to extend the deadline set out in Procedural Order No.1 for filing a settlement proposal. The OEB issued Procedural Order No. 2 on January 25, 2023 which extended the deadlines for the filing of any settlement proposal and the filing of any submission from OEB staff on a settlement proposal.

PUC Distribution requested further extensions and the OEB issued Procedural Orders No. 3, 4 and 5[4] which extended the deadlines for the filing of any settlement proposal and the filing of any submission from OEB staff on a settlement proposal.

PUC Distribution filed a settlement proposal with the OEB on March 10, 2023.

OEB staff filed its submission regarding the settlement proposal on March 17, 2023.

[4] Issued February 16, 2023, March 1, 2023 and March 7, 2023, respectively.

3 DECISION

3.1 Settlement Proposal

The settlement proposal addressed all issues on the OEB's approved Issues List for this proceeding and represented full settlement on all the issues by PUC Distribution and all intervenors. The settlement resulted in changes to a number of components of the original filing including, but not limited to, capital, OM&A, and billing determinants. The settlement proposal also included an agreement to establish three new deferral and variance accounts, and disposition of Incremental Capital Module true-ups for the SSG project and Substation 16.

The settlement proposal contained further explanation and rationale on specific issues for the OEB to consider.

OEB staff filed its submission regarding the settlement proposal on March 17, 2023. OEB staff reviewed the settlement proposal in the context of the objectives of the *Renewed Regulatory Framework for Electricity*, the *Handbook for Utility Rate Applications*, applicable OEB policies, relevant OEB decisions, and the OEB's statutory obligations and submitted that the settlement proposal reflected a reasonable evaluation of PUC Distribution's planned outcomes in this proceeding.

Findings

The OEB has considered the settlement proposal in the context of its statutory objectives under Part 1 of the *OEB Act* which include:

- Protecting consumers' interest with respect to prices and the adequacy, reliability, and quality of electricity service

- Promoting economic efficiency and cost effectiveness in the transmission and distribution of electricity while facilitating the maintenance of a financially viable electricity sector

The settlement proposal addressed all the issues on the OEB's approved Issues List for this proceeding and represented the Parties' full settlement on each of these issues. The settlement proposal, which was supported by OEB staff, contained detailed explanation and rationale on these issues for the OEB to consider.

Key features of the settlement proposal, compared to what was pre-filed by PUC Distribution, included:

- A $1.8M reduction in the 2023 Base Revenue Requirement

- A $550k reduction in the proposed 2023 OM&A expenses

- A reduction of $1.2M in the 2022 capital additions and a reduction of $750k in the 2023 capital expenditures

- A rate rider recovery mechanism for the SSG project outside of base rates for the 2023 to 2027 period, and a prudence review in PUC Distribution’s next rebasing application for any increases in this project’s costs over the settled maximum cost forecast.

For a typical residential customer with a monthly consumption of 750 kWh, the total bill impact under the filed settlement proposal is an increase of approximately $4.25 per month before taxes and the Ontario Electricity Rebate, or 3.55%. These bill impacts do not reflect anticipated energy savings that may be achieved through the implementation of the SSG project.

The OEB has the following specific comments on certain aspects of the settlement proposal.

- Reductions in PUC Distribution’s proposed capital expenditures and OM&A costs are reasonable and should not compromise the safety and reliability of PUC Distribution’s distribution system

- The OEB finds that the estimated bill impacts for PUC Distribution’s customers, resulting from the settlement proposal, are reasonable

- The proposed implementation and effective date of the rates arising from the settlement proposal of May 1, 2023, is appropriate

The OEB agrees with PUC Distribution that this settlement proposal is the culmination of extensive discussion and consideration by the Parties which represented an array of interests affected by PUC Distribution’s application for electricity distribution rates. The OEB appreciates the effort involved by the Parties to participate in this proceeding including the settlement conference. The OEB approves the settlement proposal as filed. The approved settlement proposal is attached as Schedule A to this Decision. The approved Tariff of Rates and Charges is attached as Schedule B.

4 IMPLEMENTATION

The approved effective date for new rates is May 1, 2023 as proposed by Parties.

As part of the settlement proposal, PUC Distribution filed tariff sheets and detailed supporting material, including all relevant calculations showing the impact of the implementation of the settlement proposal on its revenue requirement; the allocation of the revenue requirement to its rate classes; and the determination of the final rates and rate riders, including bill impacts.

The OEB made some minor changes to the wording and formatting on the tariff sheets attached to the settlement proposal to ensure consistency with the tariff sheets of other Ontario electricity distributors. The final approved Tariff of Rates and Charges is attached as Schedule B to this Decision and Rate Order.

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

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Schedule B of this Decision and Rate Order is approved as final effective May 1, 2023. The Tariff of Rates and Charges will apply to electricity consumed, or estimated to have been consumed, on and after May 1, 2023. PUC Distribution Inc. shall notify its customers of the rate changes no later than the delivery of the first bill reflecting the new final rates.

2. The Accounting Orders set out in Schedules C, D and E of this Decision and Rate Order are approved.

3. Intervenors shall submit their cost claims with the OEB and forward to PUC Distribution Inc. by **April 13, 2023**.

4. PUC Distribution Inc. shall file with the OEB and forward to intervenors any objections to the claimed costs by **April 24, 2023**.

5. Intervenors to which PUC Distribution Inc. filed an objection to the claimed costs, shall file with the OEB and forward to PUC Distribution Inc. any responses to any objections for cost claims by **May 1, 2023**.

6. PUC Distribution Inc. shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

Parties are responsible for ensuring that any documents they file with the OEB, such as applicant and intervenor evidence, interrogatories and responses to interrogatories or any other type of document, **do not include personal information** (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.
Please quote file number, **EB-2022-0059** for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB's online filing portal.

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address.
- Please use the document naming conventions and document submission standards outlined in the Regulatory Electronic Submission System (RESS) Document Guidelines found at the File documents online page on the OEB's website.
- Parties are encouraged to use RESS. Those who have not yet set up an account, or require assistance using the online filing portal can contact registrar@oeb.ca for assistance.
- Cost claims are filed through the OEB's online filing portal. Please visit the File documents online page of the OEB's website for more information. All participants shall download a copy of their submitted cost claim and serve it on all required parties as per the Practice Direction on Cost Awards.

All communications should be directed to the attention of the Registrar and be received by end of business, 4:45 p.m., on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Georgette Vlahos at Georgette.Vlahos@oeb.ca and OEB Counsel, Ljuba Djurdjevic at Ljuba.Djurdjevic@oeb.ca.

Email: registrar@oeb.ca

Tel: 1-877-632-2727 (Toll free)

DATED at Toronto April 6, 2023

ONTARIO ENERGY BOARD

Nancy
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Registrar

SCHEDULE A

DECISION AND ORDER

SETTLEMENT PROPOSAL

AND

PRE-SETTLEMENT CLARIFICATION RESPONSES

PUC DISTRIBUTION INC.

EB-2022-0059

APRIL 6, 2023

EB-2022-0059

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 beginning May 1, 2023.

PUC DISTRIBUTION INC.

SETTLEMENT PROPOSAL

MARCH 10, 2023

PUC Distribution Inc.
EB-2022-0059
Settlement Proposal

Table of Contents

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:

- 2023_Tariff_Schedule_and_Bill_Impact_Model_SETTLEMENT_FINAL_v5_VVO 0%
- 2023_Tariff_Schedule_and_Bill_Impact_Model_SETTLEMENT_FINAL_v5_VVO 2.7%
- 2023_Tariff_Schedule_and_Bill_Impact_Model_SETTLEMENT_FINAL_v5_VVO 5.4%
- 2023_Tariff_Schedule_SETTLEMENT_FINAL (stand alone)
- PUC_2023 Benchmarking Forecast Model_SETTLEMENT_FINAL
- PUC_2023_Cost_Allocation_Model_SETTLEMENT_FINAL_v2
- PUC_2023_Demand Profile_SETTLEMENT_FINAL
- PUC_2023_DVA_Continuity_Schedule_SETTLEMENT_FINAL_v2
- PUC_2023_Filing_Requirements_Chapter2_Appendices_SETTLEMENT_FINAL v7
- PUC_2023_GA_Analysis_Workform_SETTLEMENT_FINAL
- PUC_2023_Load Forecast - With Regression Analysis_SETTLEMENT_FINAL_v2
- PUC_2023_LRAMVA_Workform_SETTLEMENT_FINAL
- PUC_2023_Rev_Reqt_Workform_SETTLEMENT_FINAL_v3
- PUC_2023_RTSR_Workform_SETTLEMENT_FINAL_v2
- PUC_2023_Tariff of Rates and Charges_Effective_May 1 2023_v2
- PUC_2023_Test_year_Income_Tax_PILs_SETTLEMENT_FINAL_v3
- Smart Grid Project Recovery Mechanism Revenue Requirement Rate Rider_v4

No updates to pre-settlement models.

PUC Distribution Inc. ("PUC")
EB-2022-0059
Settlement Proposal

Filed with OEB: March 10, 2023

SUMMARY

In reaching this complete settlement, the Parties (as defined below) have been guided by the December 15, 2022 version of the *Filing Requirements for Electricity Distribution Rate Applications*, the approved issues list attached as Schedule A to the Ontario Energy Board's (the "OEB") Decision on Issues List of October 27, 2022 ("Approved Issues List") and the Report of the OEB titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 ("RRFE").

Capitalized terms used in this summary but not otherwise defined herein have the meaning ascribed to such terms elsewhere in this Settlement Proposal.

This Settlement Proposal reflects a complete settlement of the issues in this proceeding. Table A is a summary of the settlement on the issues in the Approved Issues List.

Table A – Issues List Summary

Issue		Status	Supporting Parties	Parties taking no position
1.1	Capital	Complete Settlement	All	None
1.2	OM&A	Complete Settlement	All	None
2.1	Revenue Requirement Components	Complete Settlement	All	None
2.2	Revenue Requirement Determination	Complete Settlement	All	None
2.3	Shared Services Cost Allocation	Complete Settlement	All	None
3.1	Load and Customer Forecast	Complete Settlement	All	None
3.2	Cost Allocation	Complete Settlement	All	None
3.3	Rate Design, including fixed/variable splits	Complete Settlement	All	None
3.4	Retail Transmission Service Rates	Complete Settlement	All	None
3.5	Specific Service Charges, Retail Service Charges, Pole Attachment Charge	Complete Settlement	All	None
3.6	Embedded Generation Rate Rider	Complete Settlement	All	None
3.7	Rate Mitigation	Complete Settlement	All	None
4.1	Impacts of Accounting Changes	Complete Settlement	All	None

4.2	Deferral and Variance Accounts	Complete Settlement	All	None
4.3	Tax Loss Carry Forward Rate Rider	Complete Settlement	All	None
5.1	Effective Date	Complete Settlement	All	None
5.2	Inclusion and true-up of amounts in rate base for ICM approved in EB-2019-0170	Complete Settlement	All	None
5.3	Inclusion and true-up of amounts in rate base for ICM approved in EB-2018-0219/EB-2020-0249	Complete Settlement	All	None
5.4	Responding appropriately to OEB directions from previous ICM application EB-2018-0219/EB-2020-0249	Complete Settlement	All	None

As a result of this Settlement Proposal, PUC has made changes to the Revenue Requirement as depicted below in Table B.

Table B: Revenue Requirement Summary

Description		Application (A)	Interrogatories (B)	Variance (C)=(B)-(A)	Settlement (D)	Variance (E)=(D)-(B)
Cost of Capital	Regulated Return on Capital	7,803,354	8,706,009	902,655	7,139,194	-1,566,815
	Regulated Rate of Return	5.73%	6.40%	0.67%	6.35%	-0.05%
Rate Base & Capital Expenditures	Rate Base	136,089,188	136,039,893	-49,294	112,442,427	-23,597,466
	Net Fixed Assets	130,431,885	130,464,363	32,478	106,598,063	-23,866,300
	Working Capital Base	75,430,704	74,340,405	-1,090,299	77,924,846	3,584,441
	Working Capital Allowance	5,657,303	5,575,530	-81,772	5,844,363	268,833
Operating Expenses	Amortization	5,425,413	5,440,457	15,044	4,563,469	-876,988
	Taxes/PILs (Grossed Up)*	574,141	684,022	109,881	764,360	80,338
	OM&A	13,533,701	13,533,701	0	12,983,701	-550,000
Revenue Requirement	Service Revenue Requirement	27,752,199	28,779,880	1,027,681	25,863,021	-2,916,859
	Other Revenue	2,750,265	2,867,022	116,757	2,654,087	-212,935
	Base Revenue Requirement	25,001,934	25,912,858	910,924	23,208,934	-2,703,924
	Grossed Up Revenue Deficiency	3,918,555	4,878,651	960,096	1,702,903	-3,175,748

The Bill Impacts as a result of this Settlement Proposal are summarized in Table C, C1 and C2 below. Table C, C-1 and C-2, respectively, represent the bill impacts assuming 2.70%, 0% and 5.4% SSG savings from VVO. The three scenarios, respectively, represent the targeted, low and high VVO savings set out in the Sault Smart Grid Project VVO Linkage to ROE Accounting Order.

Table C: Summary of Bill Impacts (2.70% Savings)

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total A		Sub-Total B		Sub-Total C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$4.01	11.3%	$3.81	9.7%	$4.07	8.9%	$2.10	1.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$4.22	5.3%	$3.65	4.1%	$4.39	4.2%	($0.94)	-0.3%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$128.73	10.4%	($87.76)	-6.2%	($68.96)	-3.7%	($268.57)	-3.1%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$14.05	8.2%	$13.02	7.0%	$14.36	6.6%	$4.85	0.8%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	$4.62	11.1%	$4.58	10.9%	$4.75	10.7%	$4.69	9.3%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$2,874.78	15.8%	$2,121.64	11.3%	$2,216.84	11.0%	$1,685.36	4.1%

Table C-1: Summary of Bill Impacts (0% Savings)

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total A		Sub-Total B		Sub-Total C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$4.01	11.3%	$3.80	9.7%	$4.26	9.3%	$4.31	3.6%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$5.87	7.3%	$5.52	6.2%	$6.74	6.4%	$6.81	2.2%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$161.44	13.0%	($56.03)	-3.9%	($23.69)	-1.3%	($38.79)	-0.4%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$18.73	11.0%	$18.10	9.7%	$20.30	9.4%	$20.53	3.6%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	$4.62	11.1%	$4.58	10.9%	$4.75	10.7%	$4.81	9.6%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$2,874.78	15.8%	$2,117.33	11.2%	$2,212.53	11.0%	$2,241.29	5.4%

Table C-2: Summary of Bill Impacts (5.40% Savings)

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total A		Sub-Total B		Sub-Total C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$4.00	11.3%	$3.81	9.7%	$3.88	8.4%	($0.10)	-0.1%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$2.58	3.2%	$1.78	2.0%	$2.04	1.9%	($8.68)	-2.8%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$94.92	7.7%	($120.59)	-8.5%	($115.32)	-6.1%	($499.58)	-5.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$9.38	5.5%	$7.95	4.3%	$8.41	3.9%	($10.83)	-1.9%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	$4.62	11.1%	$4.59	10.9%	$4.75	10.7%	$4.56	9.1%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$2,874.78	15.8%	$2,125.96	11.3%	$2,221.16	11.0%	$1,129.43	2.7%

The impact of the Settlement Proposal with regards to capital expenditures and OM&A expenses results in an estimated efficiency assessment of 1.7% above predicted costs using the PEG forecasting model provided by the OEB as can be seen in Table D.

Table D: Summary of Cost Benchmarking Results

Year	Total Cost	% Difference from Predicted	3 Year Average Performance	Efficiency Assessment
2021 Actual	$23,585,229	1.8%	2.8%	3
2022 Bridge Year	$25,082,878	1.0%	1.2%	3
2023 Test Year	$29,389,162	1.7%	2.7%	3

This Settlement Proposal also incorporates the Regulated Price Plan pricing from the OEB's Regulated Price Plan Price Report ("RPP") for November 1, 2022 to October 31, 2023 (Released October 20, 2022). This Settlement Proposal also incorporates the updated Cost of Capital Parameter Updates which were issued by the Ontario Energy Board on October 20, 2022. The Revenue Requirement in Table B incorporates all of the settled issues including the RPP and Cost of Capital Parameter Updates.

This Settlement Proposal is the culmination of extensive discussion and consideration by the Parties which represent an array of interests affected by PUC's Application for electricity distribution rates. Based on the foregoing, and the evidence and rationale provided below, the Parties agree that this Settlement Proposal is appropriate and recommend its acceptance by the OEB. Refer to Appendix E for the Proposed Tariff of Rates and Charges resulting if this Settlement Proposal is accepted by the OEB.

The Sault Smart Grid (SSG) Project was initially expected to complete the physical installation in 2022. The SSG Project is now expected to complete physical installation in 2023 and reach

Substantial Completion by November 1, 2023.[1] The Parties agree to the creation of the new Sault Smart Grid Project Recovery Mechanism. One of purposes is to allow PUC to recover the revenue requirement for the capital expenditure associated with the SSG Project. In the absence of this mechanism and due to application of the half-year rule to additions placed in service in the test year, PUC would otherwise under recover its investment in the Project over the rate plan period. Table D.1 shows the projected spending as filed in the application on August 31, 2022 as compared to the revised projection for settlement purposes.

Table D.1: Summary of SSG Project Spending Comparison

	Application		Settlement		Variance	
	2022	2023	2022	2023	2022	2023
Net Project Spending	$21,357,909	$3,190,371	$9,026,457	$15,521,823	-$12,331,452	$12,331,452

PUC has prepared an excel model entitled "Smart Grid Project Recovery Mechanism Revenue Requirement Rate Rider" ("SSG Model") for the purposes of calculating the associated rate rider revenue from 2022 and 2023 SSG Project capital additions. The entire SSG Project (comprised of 2022 net book value and 2023 capital additions) were removed from PUC's rate base for the purposes of setting 2023 base rates effective May 1, 2023. This is discussed further in Issue 5.3 below.

BACKGROUND

PUC filed a Cost of Service application with the OEB on August 31, 2022 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 charges for electricity distribution, beginning May 1, 2023 (OEB Docket Number EB-2022-0059) (the "Application").

The OEB issued and published a Notice of Hearing dated September 23, 2022, and Procedural Order No. 1 on October 18, 2022, the latter of which required the parties to the proceeding to develop a proposed issues list.

On September 27, 2022, OEB Staff sent a list of Error Checking Questions on the Application. PUC responded to these questions on October 12, 2022.

On October 24, 2022, pursuant to Procedural Order No. 1, OEB Staff submitted a proposed issues list as agreed to by the parties. OEB staff also advised the OEB that "parties may wish to raise additional matters for inclusion on the Issues List after the responses to the interrogatories are received." On October 27, 2022, the OEB issued its Decision on Issues List, approving the list

[1] For further explanation, please refer to Pre-Settlement Clarification Question CCC-55 in Appendix F

submitted by OEB Staff. This Settlement Proposal is filed with the OEB in connection with the Application and is organized in accordance with the Approved Issues List

Procedural Order No. 1 scheduled the Settlement Conference for December 12 to 14, 2022. PUC filed its Interrogatory Responses with the OEB on November 28, 2022, pursuant to which PUC updated several models and submitted them to the OEB as Excel documents.

A Settlement Conference was convened on December 12, 13, 14, 16 and 20, 2022 in accordance with the OEB's *Rules of Practice and Procedure* (the "Rules") and the OEB's *Practice Direction on Settlement Conferences* (the "Practice Direction"). Karen Wianecki acted as facilitator for the Settlement Conference.

PUC and the following Intervenors (the "Intervenors"), participated in the Settlement Conference:

Consumers Council of Canada ("CCC")
Environmental Defence Canada Inc. ("EDCI")
School Energy Coalition ("SEC"); and
Vulnerable Energy Consumers Coalition ("VECC").

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

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 OEB to settle the issues in this proceeding. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB'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 OEB 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 OEB has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

The Parties acknowledge that the Settlement Conference is privileged and confidential in accordance with the Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's *Practice Direction on Confidential Filings* and the rules of that latter document do not apply. Instead, in the 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 Conference, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are 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 in attendance via video conference 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 and partially settled issues, as applicable, 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; (b) the Appendices to this document; and (c) the evidence filed concurrently with this Settlement Proposal titled "Responses to Pre-Settlement Clarification Questions" ("Clarification Responses"). The supporting Parties for each settled issue, as applicable, agree that the evidence in respect of that settled or partially settled issue, as applicable, 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 OEB of this Settlement Proposal.

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. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the accuracy of those Appendices and 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 final Approved Issues List for the Application attached to the Decision on Issues List dated October 27, 2022.

The Parties are pleased to advise the OEB that they have reached a complete 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 OEB, none of the Parties (including Parties who take no position on that issue) will adduce any evidence or argument during the oral hearing in respect of the specific issue.	# issues settled: **ALL**
"Partial Settlement" means an issue for which there is partial settlement, as PUC 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 OEB, the Parties (including Parties who take no position on the Partial Settlement) will only adduce evidence and argument during the hearing on the portions of the issue for which no agreement has been reached.	# issues partially settled: **None**

"No Settlement" means an issue for which no settlement was reached. PUC 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. 2), 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 OEB 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 OEB does accept may continue as a valid settlement without inclusion of any part(s) that the OEB does not accept).

In the event that the OEB 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 a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue, or decide to take no position on the issue, prior to its resubmission to the OEB.

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 any of them "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.

1.0 Planning

1.1 Capital

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

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

Complete Settlement: The Parties agree that PUC will reduce its capital expenditures in the 2023 Test Year by $750,000 and reduce 2022 bridge year capital additions by $1.2 million.

The total net capital expenditures and gross capital additions in the 2023 Test Year shall, respectively, be $6.3 million and $6.8 million, as further detailed in Table 1.1A and Table 1.1B below. Table 1.1B below shows a variance of $3,940,371 from the applied for net capital expenditures. This variance includes both the reduction in $750,000 in capital expenditures plus the removal of the SSG Project from the capital expenditures.

Table 1.1A
Summary of Capital Expenditures (Excluding SSG Project)

CATEGORY	2022 Bridge Year	2023 Test Year (Forecast) $'000
System Access	2,035	2,339
System Renewal	7,129	4,356
System Service	-	
General Plant	55	150
TOTAL EXPENDITURE	9,219	6,845
Capital Contributions	511	593
Net Capital Expenditures	8,708	6,252
System O&M	6,594	7,037

Table 1.1B
2023 Test Year Capital Additions

			Application	Interrogatories	Variance	Settlement	Variance
Capital Expenditures	Gross Capital Expenditures	1808 Buildings and Fixtures	$577,035	$282,246	-$294,789	$70,346	($211,900)
		1815 Transformer Station Equipment	$275,973	$275,973	$0	$85,350	($190,623)
		1820 Distribution Station Equipment	$2,780,627	$2,780,627	$0	$1,469,155	($1,311,472)
		1830 Poles, Towers and Fixtures	$2,578,690	$2,578,690	$0	$2,297,399	($281,291)
		1835 OH Conductors and Devices	$811,945	$811,945	$0	$576,570	($235,375)
		1840 UG Conduit	$1,091,561	$1,091,561	$0	$691,868	($399,693)
		1845 UG Conduit and Devices	$174,831	$174,831	$0	$61,153	($113,678)
		1850 Line Transformers	$1,302,668	$1,302,668	$0	$788,803	($513,865)
		1855 Services	$517,876	$517,876	$0	$517,876	$0
		1860 Meters	$206,980	$206,980	$0	$206,980	$0
		1920 Computer Software	$0	$80,000	$80,000	$80,000	$0
		1940 Tools, Shop and Garage Equip	$0	$294,789	$294,789	$0	($294,789)
		1980 System Supervisory Equipment	$387,684	$387,684	$0	$0	($387,684)
	Contributed Capital		($592,500)	($592,500)	$0	($592,500)	$0
	Net Capital Expenditures		$10,113,371	$10,193,371	$80,000	$6,253,000	-$3,940,371

PUC also agrees as part of its next DSP to be filed with its next rebasing application:

(a) Asset Replacement Information: PUC will provide details on both the planned and actual number of assets replaced over the historical period, as well as a forecast of planned assets to be replaced over the5-year DSP forecast period. The number of assets replaced, or planned to be replaced, by PUC shall be broken down on an annual basis by major asset type. For 2023, no forecast information will be provided.

(b) Non-Test Year Material Capital Expenditure Information: PUC agrees to include in the next rebasing application specific information, which does not include material investment narratives, on capital expenditures for projects above the materiality threshold incurred during the IRM period that PUC seeks to add to rate base.

Based on the foregoing and the evidence filed by PUC, the Parties accept that the level of planned 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 Section 1.5, Exhibit 1; Appendix K, L and M and Exhibit 2 Appendix C PUC Distribution System Plan Section 5.2.2.1;
- The past and planned productivity initiatives of PUC as more fully detailed in Exhibit 1, Appendix B PUC Distribution's 5year Business Plan and PUC's Interrogatory Response to OEB Staff 5;
- PUC's benchmarking performance as more fully detailed in Exhibit 1, Section 1.6;
- PUC's past reliability and service quality performance as more fully detailed in Exhibit 1 Section 1.6 and Exhibit 2, Appendix C PUC's Distribution System Plan, Section 5.2.3.2;
- The total impact on distribution rates as more fully detailed in Appendix D – Bill Impacts Settlement to this Settlement Proposal;
- PUC's performance meeting government-mandated obligations as more fully detailed in the DSP;

- The settlement on OM&A as described under issue 1.2 of this Settlement Proposal;
- PUC's objectives and those of its customers as more fully detailed in Exhibit 1 Section 1.5, the chapter 2 appendices, 2-AC and exhibit 2 Appendix C PUC Distribution System Plan Section 5.2.2.1;
- PUC's DSP is as detailed in exhibit 2 Appendix C PUC Distribution System Plan; and
- PUC's business plan as more detailed in Exhibit 1, Appendix B PUC Distribution's 5 year Business Plan.

Evidence:

Application: - Exhibit 2 Section 2.1, 2.2.2 and Exhibit 2; Appendix C Distribution System Plan Section 5.2, 5.4 and Appendix C Material Invesment Narratives

IRRs: 1-Staff-3; 1-Staff-5 through 1-Staff-7; 1-Staff-9; 2-Staff-11 through 2-Staff-52; 2-VECC-2 through 2-VECC-17; 2-CCC-13 through 2-CCC-41, 2-ED-1 through 2-ED-9, 1-SEC-7; 2-SEC-9 through 2-SEC-21, 4-SEC-24

Appendices to this Settlement Proposal: Appendix 2-AB – Capital Expenditure Summary; Appendix 2-BA – 2023 Fixed Assets Continuity Schedule

Settlement Models:
PUC_2023_Filing_Requirements_Chapter2_Appendices_SETTLEMENT_FINAL

Clarification Responses: 2-Staff-115 through 2-Staff-120, 4-Staff-125; 2-SEC-2 through 2-SEC-5; CCC-53; CCC-55

Supporting Parties: All

Parties Taking No Position: None.

1.2 OM&A

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

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

Complete Settlement: PUC agrees to reduce its proposed OM&A expenses (excluding LEAP and Property Tax) in the Test Year by $550,000 to $12,983,701. The Parties agree this represents an envelope approach approval for total OM&A and that PUC may make adjustments to its OM&A plans as it sees fit.

PUC notes that it has applied the $550,000 reduction, in the tables throughout this settlement document and the live excel models, as an envelope adjustment.

As shown in Table 1.2A below, Total 2023 Settlement Test Year OM&A Expenses have increased by 15.4% compared to 2018 Actuals (representing a compound annual growth rate of 2.91%). Table 1.2B below is a Summary of OM&A expenses with changes since its original application.

Table 1.2A
Appendix 2-JA
Summary of OM&A Expenses

	2018 Last Rebasing Year OEB Approved	2018 Last Rebasing Year Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Reporting Basis							
Operations	$ 4,029,899	$ 3,679,895	$ 4,151,756	$ 4,074,970	$ 3,935,625	$ 4,028,374	$ 4,434,334
Maintenance	$ 2,106,659	$ 2,329,918	$ 2,150,490	$ 2,359,394	$ 2,471,213	$ 2,652,070	$ 2,901,131
SubTotal	**$ 6,136,558**	**$ 6,009,813**	**$ 6,302,246**	**$ 6,434,364**	**$ 6,406,837**	**$ 6,680,445**	**$ 7,335,465**
%Change (year over year)		-2.1%	4.9%	2.1%	-0.4%	4.3%	9.8%
%Change (Test Year vs Last Rebasing Year - Actual)							22.1%
Billing and Collecting	$ 1,416,684	$ 1,381,283	$ 1,354,435	$ 1,333,216	$ 1,370,350	$ 1,237,795	$ 1,290,441
Community Relations	$ 620,355	$ 595,226	$ 640,859	$ 574,049	$ 635,277	$ 697,054	$ 753,359
Administrative and General	$ 3,002,559	$ 3,264,474	$ 2,831,111	$ 2,798,172	$ 3,645,134	$ 3,540,744	$ 4,154,436
SubTotal	**$ 5,039,598**	**$ 5,240,983**	**$ 4,826,405**	**$ 4,705,436**	**$ 5,650,761**	**$ 5,475,593**	**$ 6,198,236**
%Change (year over year)		4.0%	-7.9%	-2.5%	20.1%	-3.1%	13.2%
%Change (Test Year vs Last Rebasing Year - Actual)							18.3%
Settlement Adjustment							-$550,000
Total	**$ 11,176,156**	**$ 11,250,796**	**$ 11,128,652**	**$ 11,139,800**	**$ 12,057,598**	**$ 12,156,038**	**$ 12,983,701**
%Change (year over year)		0.7%					6.8%

	2018 Last Rebasing Year OEB Approved	2018 Last Rebasing Year Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Operations[4]	$ 4,029,899	$ 3,679,895	$ 4,151,756	$ 4,074,970	$ 3,935,625	$ 4,028,374	$ 4,434,334
Maintenance[5]	$ 2,106,659	$ 2,329,918	$ 2,150,490	$ 2,359,394	$ 2,471,213	$ 2,652,070	$ 2,901,131
Billing and Collecting[6]	$ 1,416,684	$ 1,381,283	$ 1,354,435	$ 1,333,216	$ 1,370,350	$ 1,237,795	$ 1,290,441
Community Relations[7]	$ 620,355	$ 595,226	$ 640,859	$ 574,049	$ 635,277	$ 697,054	$ 753,359
Administrative and General[8]	$ 3,002,559	$ 3,264,474	$ 2,831,111	$ 2,798,172	$ 3,645,134	$ 3,540,744	$ 4,154,436
Settlement Adjustment							-$ 550,000
Total	**$ 11,176,156**	**$ 11,250,796**	**$ 11,128,652**	**$ 11,139,800**	**$ 12,057,598**	**$ 12,156,038**	**$ 12,983,701**
%Change (year over year)		0.7%	-1.1%	0.1%	8.2%	0.8%	6.8%

Table 1.2B
Summary of OM&A Expenses with Variance

	2023 Test Year Original Application	2023 Test Year Interrogatories	Variance	2023 Test Year Settlement Proposal	Variance
Operations	$4,434,334	$4,434,334	$0	$4,434,334	$0
Maintenance	$2,901,131	$2,901,131	$0	$2,901,131	$0
SubTotal	$7,335,465	$7,335,465	$0	$7,335,465	$0
Billing and Collecting	$1,290,441	$1,290,441	$0	$1,290,441	$0
Community Relations	$753,359	$753,359	$0	$753,359	$0
Administrative and General	$4,154,436	$4,154,436	$0	$4,154,436	$0
OM&A Settement Reduction	$0	$0	$0	($550,000)	($550,000)
SubTotal	$13,533,701	$13,533,701	$0	$12,983,701	($550,000)
Property Taxes	$384,446	$384,446	$0	$384,446	$0
LEAP	$31,144	$31,245	$101	$27,845	($3,400)
Total	$13,949,291	$13,949,392	$101	$13,395,992	($553,400)

Based on the foregoing and the evidence filed by PUC, the Parties accept the level of planned OM&A expenditures, and accept that 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 Section 1.5, Exhibit 1; Appendix K, L and M and Exhibit 2 Appendix C PUC Distribution System Plan Section 5.2.2.1;
- The past and planned productivity initiatives of PUC as more fully detailed in Exhibit 1, Appendix B PUC Distribution's 5year Business Plan and PUC's Interrogatory Response to OEB Staff 5;
- PUC's benchmarking performance as more fully detailed in Exhibit 1, Section 1.6;
- PUC's past reliability and service quality performance as more fully detailed in Exhibit 1 Section 1.6 and Exhibit 2, Appendix C PUC's Distribution System Plan, Section 5.2.3.2;
- The total impact on distribution rates as more fully detailed in Appendix D – Bill Impacts Settlement to this Settlement Proposal;
- PUC's performance meeting government-mandated obligations as more fully detailed in the DSP;
- The settlement on OM&A as described under issue 1.2 of this Settlement Proposal;
- PUC's objectives and those of its customers as more fully detailed in Exhibit 1 Section 1.5, the chapter 2 appendices, 2-AC and exhibit 2 Appendix C PUC Distribution System Plan Section 5.2.2.1;
- PUC's DSP as detailed in exhibit 2 Appendix C PUC Distribution System Plan; and
- PUC's business plan as more detailed in as more detailed in Exhibit 1, Appendix B PUC Distribution's 5 year Business Plan.

Evidence:

Application: Exhibit 4, Sections 4.1, 4.2, and 4.3

IRR's: 1-Staff-60 through 1-Staff-83; 4-VECC-27 through 4-VECC-35; 4-CCC-42 through 4-CCC-48; 4-SEC-23 through 4-SEC-30

Appendices to this Settlement Proposal: Appendix 2-JA*, 2-K*, 2-M*
*PUC has used an envelope adjustment of ($550,000) in these appendices to reflect the reduced settlement amount of OM&A.

Settlement Models: PUC_2023_Rev_Reqt_Workform_SETTLEMENT_FINAL; PUC_2023_Filing_Requirements_Chapter2_Appendices_SETTLEMENT_FINAL

Clarification Responses: 1-Staff-112, 4-Staff-123, CCC-50, CCC-56

Supporting Parties: All

Parties Taking No Position: None.

2.0 Revenue Requirement

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

Complete Settlement: The Parties accept that the components of Base Revenue Requirement (See Table 2.2A below) on which they have reached settlement are reasonable and have been appropriately determine in accordance with OEB policies and practices. Specifically:

a) Rate Base (See Table 2.2B below): Subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept that the rate base calculations have been appropriately determined in accordance with OEB policies and practices. See also section 1.1 above regarding the reductions in 2022 bridge year capital additions.

The Parties have agreed to the inclusion of the net book value for the Substation-16 Project, initially approved as an ICM in EB-2019-0170. The amount includes additional costs incurred as outlined in Exhibit 2 Table 2-24.

The Parties agreed that the entire SSG Project capital related costs are to be removed from the from 2023 rate base for the purposes of calculating 2023 test year revenue requirement. The SSG Project capital related costs are addressed in the SSG Project Recovery Mechanism in Issue 5.3 below.

b) Working Capital (see Table 2.2B below): The Parties accept that the working capital calculations have been appropriately determined in accordance with OEB policies and practices. Tables 2.2B and 2.2C identify the agreed upon elements of the working capital and cost of power.

c) Cost of Capital (see Table 2.2E below): The Parties agree the cost of capital parameters are appropriate and have been determined in accordance with OEB policies and practices. Table 2.2E provides the agreed upon elements of the cost of capital.

PUC has agreed to reduce the total debt by $10,136,300 and apply that reduction to PUC's most recent debt, which is financing from Infrastructure Ontario. This will reduce PUC's weighted long-term debt to 4.31%. The parties have also agreed to use the OEB's Long Term debt rate of 4.88% on financing secured in 2023. Table 2.1A below show the 2023 Test Year Debt.

Table 2.1A: 2-OB Debt Instruments

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	23-Jun-05	No Term	$ 26,534,040	4.88%	$1,294,861.15
2	Loan - Smart Meter Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jul-13	15	$ 2,344,765	3.82%	$ 89,570.03
3	Loan - PUC Admin Building	Infrastructure Ontario	Third-Party	Fixed Rate	1-Oct-13	25	$ 16,012,864	4.57%	$ 731,787.88
4	Loan	Infrastructure Ontario	Third-Party	Fixed Rate	16-Jun-16	25	$ 12,210,836	3.47%	$ 423,716.02
5	Loan $5.8MM drawdown	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jan-21	15	$ 5,156,998	2.11%	$ 108,812.66
6	Loan $4.0MM drawdown	Infrastructure Ontario	Third-Party	Fixed Rate	1-Mar-22	15	$ 3,885,023	3.65%	$ 141,803.33
7	Loan - SSG financing	Infrastructure Ontario	Third-Party	Fixed Rate	1-Jan-23	20	$ 10,063,700	4.88%	$ 491,108.56
Total							$ 76,208,226	4.31%	$3,281,659.63

d) Other Revenue (see Table 2.2G below): The Parties accept that the other revenue calculations have been appropriately determined in accordance with OEB policies and practices.

e) Depreciation (see Table 2.2B below): The Parties accept that the depreciation calculations have been appropriately determined in accordance with OEB policies and practices. The depreciation calculations do not include SSG Project and related NRCan funding amounts for the SSG Project as the SSG Project and NRCan funding has been included in the SSG Project Recovery Mechanism.

f) PILS (see Table 2.2F below): The Parties agree that the PILs calculations, excluding the SSG Project as updated to reflect this Settlement Proposal, have been appropriately determined in accordance with OEB policies and practices.

The Parties agree that the PILs calculations reflect a 5-year smoothing method for capital cost allowance (CCA) based on 2023 capital additions, excluding the SSG Project.

All tax loss carry forwards have been dealt with in section 4.3 below.

g) Loss Factors: The Parties accept that the loss factors have been appropriately determined in accordance with OEB policies and practices. See settlement on Issue 3.1 below.

Evidence:

Application: Exhibit 2 Sections 2.1 through 2.8; Exhibit 4 Section 4.1 and 4.2; Exhibit 5 Sections 5.1 and 5.2; Exhibit 6 Sections 6.1, 6.2, and 6.3; Exhibit 8 Sections 8.2 through 8.8.

IRRs: 1-Staff-10 through 1-Staff-14, 1-Staff-17 through 1-Staff-22, 1-Staff-24 through 1-Staff-27, 5-Staff 84 through 6-Staff-93, 8-Staff-97 through 8-Staff-101; VECC-2 through VECC-8, VECC-36 through VECC-40, VECC-50, VECC-51, CCC-13, CCC-16, SEC-9, SEC-10, SEC-31 through SEC-35**.**

Appendices to this Settlement Proposal: N/A

Settlement Models: PUC_2023_Rev_Reqt_Workform_SETTLEMENT_FINAL
PUC_2023_Test_year_Income_Tax_PILs_SETTLEMENT_FINAL

Clarification Responses: 2-Staff-114, 2-Staff-115, 2-Staff-119, 2-Staff-120, 6-Staff-126 through 8-Staff-128, SEC-6, VECC-57, CCC-54, CCC-55.

Supporting Parties: All

Parties Taking No Position: None

2.2 *Has the revenue requirement been accurately determined based on these elements?*

Complete Settlement: The Parties agree that the revenue requirement has been accurately determined based on these elements.

The elements of Revenue Requirement are detailed in Tables 2.2A to 2.2G below.

Table 2.2A
Revenue Requirement

	Original Application	Interrogatories	Change	Settlement Proposal	Change	Total Change
OM&A	$13,533,701	$13,533,701	$0	$12,983,701	($550,000)	($550,000)
Amortization / Depreciation	$5,425,413	$5,440,457	$15,044	$4,563,469	($876,988)	($861,944)
Taxes other than income tax	$384,446	$384,446	$0	$384,446	$0	$0
LEAP	$31,144	$31,245	$101	$27,850	($3,395)	($3,294)
Total	$19,374,704	$19,389,849	$15,145	$17,959,466	($1,430,383)	($1,415,238)
Regulated Return on Capital	$7,803,354	$8,706,008	$902,654	$7,139,194	($1,566,814)	($664,160)
Income Taxes (Grossed Up)	$574,141	$684,022	$109,881	$764,361	$80,339	$190,220
Service Revenue Requirement	**$27,752,199**	**$28,779,879**	$1,027,680	**$25,863,021**	($2,916,859)	($1,889,179)
Other Revenues	$2,750,265	$2,867,022	$116,757	$2,654,087	($212,935)	($96,178)
Base Revenue Requirement	**$25,001,934**	**$25,912,857**	$910,923	**$23,208,934**	($2,703,924)	($1,793,001)
Distribution Revenue at Current Rates	$21,083,379	$21,034,207	($49,172)	$21,506,030	$471,823	$422,651
Grossed up Revenue Deficiency	**$3,918,555**	**$4,878,650**	$960,095	**$1,702,904**	($3,175,747)	($2,215,652)

Table 2.2B
Rate Base

	Original Application	Interrogatories	Change	Settlement Proposal	Change	Total Change
Average Gross Capital	$166,892,585	$166,932,585	$40,000	$142,404,491	($24,528,094)	($24,488,094)
Average Accumulated Depreciation	($36,460,700)	($36,468,222)	($7,522)	($35,806,428)	$661,794	$654,272
Average Net Book Value	$130,431,885	$130,464,363	$32,478	$106,598,063	($23,866,300)	($23,833,822)
Working Capital Base	$75,430,704	$74,340,405	($1,090,299)	$77,924,846	$3,584,441	$2,494,142
Working Capital Allowance %	7.5%	7.5%	0.0%	7.5%	0.0%	0.0%
Working Capital $	$5,657,303	$5,575,530	($81,772)	$5,844,363	$268,833	$187,061
Rate Base	$136,089,188	$136,039,893	($49,294)	$112,442,427	($23,597,466)	($23,646,761)

Table 2.2C
Cost of Power

	Original Application	Interrogatories	Change	Settlement Proposal	Change	Total Change
Power Purchased	$48,212,727	$48,995,178	$782,451	$51,522,165	$2,526,987	$3,309,438
Glodal Adjustment	$13,750,802	$8,678,211	($5,072,591)	$9,179,727	$501,516	($4,571,075)
Wholesale Market Service Charge	$2,058,742	$2,045,916	($12,826)	$2,851,285	$805,370	$792,544
RTSR - Network	$5,092,749	$5,403,037	$310,288	$5,832,243	$429,206	$739,494
Embedded Generation	($289,386)	($287,584)	$1,803	($242,255)	$45,328	$47,131
Smart Metering	$174,098	$170,050	($4,049)	$170,050	$0	($4,049)
RRRP	$302,756	$300,870	($1,886)	$443,533	$142,663	$140,777
OER Credit	($7,821,075)	($4,914,664)	$2,906,411	($5,227,899)	($313,235)	$2,593,176
Total Cost of Power	$61,481,413	$60,391,013	($1,090,399)	$64,528,849	$4,137,836	$3,047,436

Table 2.2D
Cost of Power Settlement Proposal- Reconciliation of OER to Cost of Power Categories

	Cost	OER Credit	Total
Power Purchased	$51,522,165	($4,446,449)	$47,075,716
Glodal Adjustment	$9,179,727		$9,179,727
Wholesale Market Service Charge	$2,851,285	($246,071)	$2,605,215
RTSR - Network	$5,832,243	($503,332)	$5,328,911
Embedded Generation	($242,255)	$20,907	($221,348)
Smart Metering	$170,050	($14,676)	$155,374
RRRP	$443,533	($38,278)	$405,256
OER Credit	($5,227,899)		($5,227,899)
Total Cost of Power	$64,528,849	($5,227,899)	$59,300,951

Table 2.2E
Cost of Capital

		Application	Interrogatories	Change	Settlement Proposal	Change	Total Change
Capitalization Ratios	Long Term Debt	56%	56%	0%	56%	0%	0%
	Short Term Debt	4%	4%	0%	4%	0%	0%
	Equity	40%	40%	0%	40%	0%	0%
	Total	100%	100%	0%	100%	0%	0%
	Total Debt Only	60%	60%	0%	60%	0%	0%
Allocation of Rate Base	Long Term Debt	$76,209,945	$76,182,340	($27,605)	$62,967,759	($13,214,581)	($13,242,186)
	Short Term Debt	$5,443,568	$5,441,596	($1,972)	$4,497,697	($943,899)	($945,870)
	Equity	$54,435,675	$54,415,957	($19,718)	$44,976,971	($9,438,987)	($9,458,705)
	Total Rate Base	$136,089,188	$136,039,893	($49,294)	$112,442,426	($23,597,467)	($23,646,761)
Rates of Return	Weighted Long Term Debt Rate	3.97%	4.40%	0.43%	4.31%	-0.09%	0.34%
	Short Term Debt Rate	1.17%	4.79%	3.62%	4.79%	0.00%	3.62%
	Return on Equity	8.66%	9.36%	0.70%	9.36%	0.00%	0.70%
	Weighted Average Cost of Capital	5.73%	6.40%	0.67%	6.35%	-0.05%	0.62%
Return on Rate Base	Long Term Debt	$3,025,535	$3,352,023	$326,488	$2,713,910	($638,113)	($311,624)
	Short Term Debt	$63,690	$260,652	$196,963	$215,440	($45,213)	$151,750
	Return on Equity	$4,714,129	$5,093,334	$379,204	$4,209,844	($883,489)	($504,285)
	Total Return on Rate Base	$7,803,354	$8,706,009	$902,655	$7,139,195	($1,566,814)	($664,159)

Table 2.2F
Calculation of Adjustment for PILS CCA Smoothing

Forecast Period Test Year Vs. Test Year Capital Expenditures	2023	2024	2025	2026	2027	Total	5 Year Average
Accelerated CCA no Phase out	$818,650	$818,650	$818,650	$818,650	$818,650	$4,093,248	$818,650
Accelerated CCA Phase out in 2024-2027	$818,650	$572,433	$572,433	$572,433	$572,433	$3,108,382	$621,676
CCA Adjustment	$0	$246,217	$246,217	$246,217	$246,217		$196,973
				Adjustment to Accounting Income			**$196,973**

Table 2.2G
Other Revenue

Other Revenue	Accounts Included	Original Application	Interrogatories	Change	Settlement Proposal	Change	Total Change
Specific Service Charges		$26,520	$26,520	$0	$26,520	$0	$0
Late Paymet Charges	4225	$230,292	$230,292	$0	$230,292	($0)	($0)
Other Revenue	4084, 4086, 4210, 4235, 4325	$2,365,053	$2,481,810	$116,757	$2,268,875	($212,935)	($96,178)
Other Income or Deductions	4325, 4390	$128,400	$128,400	$0	$128,400	$0	$0
Total Other Revenues		$2,750,265	$2,867,022	$116,757	$2,654,087	($212,935)	($96,178)

Evidence:

Application: Exhibit 2 Sections 2.1 through 2.8; Exhibit 4 Section 4.1 and 4.2; Exhibit 5 Sections 5.1 and 5.2; Exhibit 6 Sections 6.1, 6.2, and 6.3; Exhibit 8 Sections 8.2 through 8.8

IRRs: 1-Staff-10 through 1-Staff-14, 1-Staff-17 through 1-Staff-22, 1-Staff-24 through 1-Staff-27, 5-Staff 84 through 6-Staff-93, 8-Staff-97 through 8-Staff-101; VECC-2 through VECC-8, VECC-36 through VECC-40, VECC-50, VECC-51, CCC-13, CCC-16, SEC-9, SEC-10, SEC-31 through SEC-35

Appendices to this Settlement Proposal: N/A

Settlement Models: PUC_2023_Rev_Reqt_Workform_SETTLEMENT_FINAL
PUC_2023_Test_year_Income_Tax_PILs_SETTLEMENT_FINAL

Clarification Responses: 2-Staff-114, 2-Staff-115, 2-Staff-119, 2-Staff-120, 6-Staff-126 through 8-Staff-128, SEC-6, VECC-57, CCC-54, CCC-55.

Supporting Parties: All

Parties Taking No Position: None

2.3 *Is the proposed shared services cost allocation methodology and the quantum appropriate?*

Complete Settlement: The Parties accept that the proposed shared services cost allocation methodology and quantum have been appropriately determined in accordance with OEB policies and practices.

Evidence:

Application: Exhibit 1, section 1.2; Exhibit 4 sections 4.1 and 4.3.3; Exhibit 6, Section 6.3.1

IRRs: Staff-69, Staff-73, Staff-74, Staff-75, Staff-76, Staff-77 and Staff-78.

Appendices to this Settlement Proposal: N/A

Settlement Models:
PUC_2023_Filing_Requirements_Chapter2_Appendices_SETTLEMENT_FINAL

Clarification Responses: CCC-50, CCC-56.

Supporting Parties: All

Parties Taking No Position: None

3.0 Load Forecast, Cost Allocation and Rate Design

3.1 *Are the proposed load and customer forecast including the application of Conservation and Demand Management savings, loss factors, and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the energy and demand requirements of PUC Distribution Inc.'s customers?*

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties agree that the customer forecast including the application of Conservation and Demand Management savings, loss factors, and resulting billing determinants are an appropriate reflection of the energy and demand requirements of PUC's customers.

The Parties accept that PUC will adjust its load forecast trend variable by holding it constant at its December 31, 2021 value and then only use 20% of the 2023 CDM adjustment. PUC has also agreed in its response to Interrogatories VECC-55 that the number of customer explanatory variable is insignificant and therefore has been removed.

The billing determinants are reproduced below as Table 3.1A:

Table 3.1A
Billing Determinants

Rate Class	Item	Application	Interrogatories	Change	Settlement Proposal	Change	Total Change
Residential	Customers	30,340	30,340	0	30,340	0	0
	kWh	274,738,681	273,629,866	(1,108,815)	282,922,375	9,292,509	8,183,694
GS<50	Customers	3,400	3,400	0	3,400	0	0
	kWh	79,051,528	78,837,024	(214,504)	86,539,469	7,702,445	7,487,941
GS>50	Customers	344	344	0	344	0	0
	kWh	221,450,388	219,167,959	(2,282,429)	232,644,288	13,476,329	11,193,900
	kW	547,687	542,043	(5,644)	575,372	33,329	27,685
Sentinel Lighting	Connectons	317	317	0	317	0	0
	kWh	193,841	193,841	0	193,841	0	0
	kW	566	566	0	566	0	0
Street Lighting	Connections	8,037	8,037	0	8,037	0	0
	kWh	2,459,994	2,459,994	0	2,459,994	0	0
	kW	7,200	7,200	0	7,200	0	0
USL	Customers	25	25	0	25	0	0
	kWh	878,528	878,528	0	878,528	0	0
Total Customers/Connections		42,463	42,463	0	42,463	0	0
Total kWh		578,772,960	575,167,212	(3,605,748)	605,638,495	30,471,283	26,865,535
Total kW		555,453	549,809	(5,644)	583,138	33,329	27,685

The loss factor calculation is reproduced below as Table 3.1B:

Table 3.1B
Loss Factor
Appendix 2R

		Historical Years					5-Year Average
		2017	2018	2019	2020	2021	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	652,970,471	666,736,298	660,423,172	640,745,749	628,757,114	649,926,561
A(2)	"Wholesale" kWh delivered to distributor (lower value)	652,970,471	666,736,298	660,423,172	640,745,749	628,757,114	649,926,561
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	652,970,471	666,736,298	660,423,172	640,745,749	628,757,114	649,926,561
D	"Retail" kWh delivered by distributor	622,542,513	633,697,927	631,945,814	613,632,199	604,318,512	621,227,393
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	622,542,513	633,697,927	631,945,814	613,632,199	604,318,512	621,227,393
G	Loss Factor in Distributor's system = **C / F**	1.0489	1.0521	1.0451	1.0442	1.0404	1.0462
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
	Total Losses						
I	Total Loss Factor = **G x H**	1.0489	1.0521	1.0451	1.0442	1.0404	1.0462

Evidence:

Application: Exhibit 3 Section 3.1 and 3.2

IRRS: 3-Staff-53 through 3-Staff-59, 8-Staff-97; VECC-18 through VECC-26, SEC-22

Appendices to this Settlement Proposal: N/A

Settlement Models: PUC_2023_Load Forecast - With Regression Analysis_SETTLEMENT_FINAL, PUC_2023_Rev_Reqt_Workform_SETTLEMENT_FINAL

Clarification Responses: 3-Staff-121, 3-Staff-122, VECC-55,VECC-56

Supporting Parties: All

Parties Taking No Position: None.

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

Complete Settlement: The Parties accept that PUC's proposals on cost allocation methodology, allocations, and revenue-to-cost ratios are appropriate.

However, in terms of the load profiles used, while Parties agree to accept the demand allocators proposed by PUC for purposes of settlement as they are reasonable, there is no agreement that the methodology used to derive the values is appropriate.

The revenue-to-cost ratios are reproduced below in Table 3.2A.

Table 3.2A
Revenue to Cost Ratios

Rate Class	Revenue to Cost Ratios resulting from Cost Allocation Model	Proposed Revenue to Cost Ratios	OEB Target Low	OEB Target High
Residential	95.8%	95.8%	85%	115%
GS<50	119.6%	119.6%	80%	120%
GS>50	101.3%	101.3%	80%	120%
Sentinel Light	92.9%	92.9%	80%	120%
Street Light	87.1%	87.1%	80%	120%
USL	101.9%	101.9%	80%	120%

Evidence:

Application: Exhibit 1 Section 1.2.6; Exhibit 7 Section 7.1, 7.2 and 7.3.

IRRs: 7-Staff-94, 7-Staff-95; VECC-41 through VECC-44

Appendices to this Settlement Proposal: Appendix-A Updated Revenue Requirement Workform

Settlement Models:PUC_2023_Cost_Allocation_Model_SETTLEMENT_FINAL; PUC_2023_Rev_Reqt_Workform_SETTLEMENT_FINAL

Clarification Responses: None

Supporting Parties: All

Parties Taking No Position: None

3.3 *Are PUC Distribution Inc.'s proposals, including the proposed fixed/variable splits, for rate design appropriate?*

Complete Settlement: The Parties agree that PUC's proposals for rate design, including the proposed fixed/variable splits are appropriate.

For classes above minimum peak load carrying capability (PLCC), the Parties agree that that the current fixed rate remain unchanged. This includes both general service classes and unmetered scattered load (USL).

The fixed-variable splits and the resultant proposed fixed and variable charges are reproduced below in Tables 3.3A and 3.3B.

Table 3.3A
Fixed Variable Split

Rate Class	Allocated Base Revenue Requirement	Percentage from Fixed	Percentage from Variable	Fixed Component of Revenue Requirement	Variable Component of Revenue Requirement	Transformer Allowance
Residential	$13,963,979	100.0%	0.0%	$13,963,979	$0	
GS<50	$3,669,692	24.8%	75.2%	$910,656	$2,759,036	
GS>50	$5,249,737	9.7%	90.3%	$508,859	$4,740,878	$67,200
Sentinel Light	$39,540	41.8%	58.2%	$16,544	$22,996	
Street Light	$240,078	67.2%	32.8%	$161,325	$78,753	
USL	$45,908	8.9%	91.1%	$4,101	$41,807	
Total	$23,208,934			$15,565,464	$7,643,470	$67,200

Table 3.3B
Proposed Distribution Rates

Rate Class	Variable Biling Unit	Settlement Proposal	
		Proposed Monthly Charge	Proposed Variable Rate
Residential	kWh	38.35	0
GS<50	kWh	22.32	0.0319
GS>50	kW	123.27	8.3565
Sentinel Light	kW	4.35	40.6108
Street Light	kW	1.67	10.9378
USL	kWh	13.67	0.0476

Evidence:

Application: Exhibit 1 Section 1.2.6; Exhibit 8 Section 8.1, 8.9, 8.10 and 8.11

IRRs: 8-Staff-96 though 8-Staff-101; VECC-45 through VECC-51

Appendices to this Settlement Proposal: Appendix-A Updated Revenue Requirement Workform

Settlement Models:
PUC_2023_Cost_Allocation_Model_SETTLEMENT_FINAL;
PUC_2023_Rev_Reqt_Workform_SETTLEMENT_FINAL

Clarification Responses: 8-Staff-128, SEC-7

Supporting Parties: All

Parties Taking No Position: None.

3.4 *Are the proposed Retail Transmission Service Rates appropriate?*

Complete Settlement: The Parties agree that the proposed Retail Transmission Service Rates are appropriate. For clarity, the Retail Transmission Service Rates only include the Network Service Rate of Rate Schedule Provincial Transmission Service. The Transformation Connection Service Rate and Line Connection Service Rate do not apply as PUC owns the transformation stations connected to Hydro One's network.

The Retail Transmission Service Rates have been reproduced below in Table 3.4A.

Table 3.4A
Retail Transmission Service Rates (RTSR)

Rate Class	Proposed RTSR Network Rate
Residential	0.0092
GS<50	0.0086
GS>50	3.4567
GS>50 Interval Metered	4.3474
Sentinel Light	2.6202
Street Light	2.6073
USL	0.0086

Evidence:

Application: Exhibit 8 Section 8.2

IRRs: 8-Staff-100; VECC-47

Appendices to this Settlement Proposal: Appendix-E Draft Tariff of Rates and Charges

Settlement Models:
2023_Tariff_Schedule_and_Bill_Impact_Model_SETTLEMENT_FINAL;
PUC_2023_RTSR_Workform_SETTLEMENT_FNAL

Clarification Responses: None

Supporting Parties: All

Parties Taking No Position: None.

3.5 *Are the Specific Service Charges, Retail Service Charges, and Pole Attachment Charge appropriate?*

Complete Settlement: The Parties agree that PUC's proposed Specific Service Charges, Retail Service Charges and Pole Attachment Charge, are appropriate as shown in the Tariff Schedule and Bill Impacts Model.

Evidence:

Application: Exhibit 8 Section 8.3 through 8.7

IRRs: 8-Staff-98, 8-Staff-101, VECC-49, VECC-51

Appendices to this Settlement Proposal: Appendix-E Draft Tariff of Rates and Charges

Settlement Models:
2023_Tariff_Schedule_and_Bill_Impact_Model_SETTLEMENT_FINAL;

Clarification Responses: None

Supporting Parties: All

Parties Taking No Position: None.

3.6 *Is the proposed Embedded Generation Rate Rider appropriate?*

Complete Settlement: The Parties agree that PUC's proposed Embedded Generation Rate Rider is appropriate as shown in Table 3.6A below. Details on the Embedded Generation Rate Rider are provided on pages 12-13 of Exhibit 8.

Table 3.6A
Embedded Generation Rate Rider

Rate Class	Units	kWh	Allocated Group 1 Balance	Rate Rider for DVA Accounts	Actual Credit Due to Rounding
Residential	kWh	282,922,375	($124,479)	($0.0004)	($113,169)
GS<50	kWh	86,539,469	($38,075)	($0.0004)	($34,616)
GS>50	kWh	232,644,288	($102,358)	($0.0004)	($93,058)
USL	kWh	878,528	($387)	($0.0004)	($351)
Sentinel	kWh	193,841	($85)	($0.0004)	($78)
Street Light	kWh	2,459,994	($1,082)	($0.0004)	($984)
		605,638,495	($266,466)		($242,255)

Evidence:

Application: Exhibit 8 Section 8.4

IRRs: VECC-51

Appendices to this Settlement Proposal: Appendix-E Draft Tariff of Rates and Charges

Settlement Models:
2023_Tariff_Schedule_and_Bill_Impact_Model_SETTLEMENT_FINAL

Clarification Responses: None

Supporting Parties: All

Parties Taking No Position: None.

3.7 *Are rate mitigation proposals required for any rate classes?*

Complete Settlement: The Parties agree that rate mitigation proposals are not required for any of PUC's rate classes.

Please see Table C in the summary section above for the summary of bill impacts.

Evidence:

Application: Exhibit 8 Section 8.12

IRRs: None

Appendices to this Settlement Proposal: None

Settlement Models: None

Clarification Responses: None

Supporting Parties: All

Parties Taking No Position: None.

4.0 Accounting

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

Complete Settlement: The Parties accept that all impacts of any changes in accounting standards, policies, estimates and adjustments have been properly identified and recorded, and the rate-making treatment of each of these impacts is appropriate.

Evidence:

Application: Exhibit 1 Section 1.3 and Section 1.8; Exhibit 2 Section 2.4 and 2.9

IRRs: 2-Staff-15, 6-Staff-93, 9-Staff-104

Appendices to this Settlement Proposal: None

Settlement Models:
2023_Tariff_Schedule_and_Bill_Impact_Model_SETTLEMENT_FINAL

Clarification Responses: None

Supporting Parties: All

Parties Taking No Position: None.

4.2 *Are PUC Distribution Inc.'s proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts, requests for discontinuation of accounts, and the continuation of existing accounts, appropriate?*

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties agree that PUC's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, discontinuation of accounts, continuation of existing accounts, and establishment of new accounts are appropriate.

The Parties agree to the following:

1. Account 1509 – Impacts Arising from the COVID-19 Emergency – The Parties agreed to a disposition of the revised account balance and carrying charges of $326,141 as of December 31, 2021. As compared to the pre-filed amount requested for disposition, the Parties agreed to exclude the 2021 amount of $50,239 from disposition as it did not reach the materiality threshold. The Parties also agreed to exclude $26,654 in the 2020 amount for executive labour costs associated with the COVID-19 emergency. The account will be closed upon disposition.

2. Account 1592 – PILs and Tax Variance, Sub-account CCA Changes – The Parties agree that the balance as at December 31, 2022 in Account 1592 will be refunded to ratepayers through the Tax Loss Carry Forward Rate Rider as noted in section 4.3.

   The test year PILs calculations reflect a 5-year smoothing method of CCA (see section 2.1F). Therefore, no new entries will be recorded in Account 1592, PILs and Tax Variances, Sub-account CCA Changes, subsequent to December 31, 2022, unless there are further changes to the current tax laws and rules governing CCA, not contemplated in the current proceeding, or if the OEB orders otherwise.

   PUC will only utilize Account 1592 - PILs and Tax Variances, Sub-account CCA Changes to record the impact of any further changes of the current tax laws and rules governing CCA from the CCA rules that are currently anticipated for the phase out of accelerated CCA . For greater certainty, it is the intention of the Parties that if the accelerated CCA is continued past its scheduled expiry date, a credit will be booked for the benefit of ratepayers, to be returned to them in accordance with the OEB's policies for deferral and variance account dispositions.

3. Account 1508 – Sub-account Substation SSG ICM – The Parties have agreed to a rate rider refund to customers based on the ICM true-up calculation presented in Table 5.3B. The sub-accounts related to the SSG ICM will be transferred to the appropriate accounts and closed. The treatment of SSG Project moving forward is discussed in the SSG Project Recovery Mechanism under Issue 5.3.

4. Account 1508 – Sub-account Substation 16 ICM – For the purposes of the ICM true up calculation, the Parties agreed that the half year rule will apply in the first year of the ICM and that the first year was 2021, instead of 2020, to reflect the year the

Substation 16 Project actually went in-service. The Parties have agreed to a rate rider refund to customers based on the ICM true-up calculation presented in Table 5.2B. The sub-accounts related to the Substation 16 ICM will be transferred to the appropriate accounts and closed.

5. Account 1508 – Sub-account SSG Project Recovery Mechanism Variance Account – A new DVA account will be created for the period of May 1, 2023 to April 30, 2028 to record an asymmetrical true-up for the recovery of the SSG Project during this time, to the benefit of ratepayers. PUC's net recovery for the SSG Project after considering this sub-account will be the lower of

    a. total rate riders collected from May 1, 2023 to April 30, 2028

    b. the sum of 2023 to 2027 revenue requirements, where the annual revenue requirement is the lower of i) the recalculated revenue requirement based on actual SSG Project capital costs and in-service dates, and ii) the settled forecasted revenue requirement used to calculate the SSG Recovery Mechanism Rate Rider.

    The full details of the sub-account are further outlined in the "2023 Cost of Service Accounting Order – SSG Project Recovery Mechanism Variance Account" provided in Appendix I.

6. Account 1508 – Sub-account Incremental VVO Costs or Savings– A new DVA account will be created to record incremental VVO savings or costs to customers in a given year. These savings or costs will be dependent on the VVO percentage savings achieved as measured against the target of 2.7%, as outlined in "2023 Cost of Service Accounting Order –Sault Smart Grid Project VVO Linkage to ROE" provided in Appendix G.

7. Account 1508 – Sub-account EPC Contract Liquidated Damages – A new DVA account will be created to record the revenue requirement impact of any liquidated damages received by PUC for the SSG so that the reduction to the settled upon SSG revenue requirement resulting from liquidated damages is returned to ratepayers. The details are as outlined in "2023 Cost of Service Accounting Order – SSG EPC Contract Liquidated Damages" provided in Appendix H.

8. The amounts for disposition in the following accounts include 2022 forecasted principal amounts. Some of these accounts will be subsequently closed, effective May 1, 2023 as noted in Table 4.2C of this settlement proposal.

    a. Pole attachment variance (Account 1508);

    b. Retail Cost Variance Account – Retail (Account 1518);

    c. Retail Cost Variance Account - STR (Account 1548);

    d. LRAMVA (Account 1568); and

e. Impacts Arising from the COVID-19 Emergency (Account 1509).

9. The disposition period for all deferral and variance accounts will be 12 months.

Table 4.2A below sets out the Deferral and Variance Account balances as updated to reflect this Settlement Proposal. Table 4.2B below details proposed rate riders. Table 4.2C below includes a listing of the DVAs that are continuing/discontinuing as of the effective date.

Table 4.2A
Deferral and Variance Account Balances

	USofA Account Number	Account Name	Balances Claimed	DVA Balances not being disposed	Principal Claim	Interest Claim	Total Claim	Disposition Method
Group 1	1551	Smart Metering Entity Charge Variance Account	2021		($16,703)	($491)	($17,194)	Rate Rider Group 1
	1580	RSVA - Wholesale Market Service Charge	2021		$887,109	$27,182	$914,291	Rate Rider Group 1
	1580	Variance WMS – Sub-account CBR Class B	2021		($74,105)	($2,435)	($76,540)	Rate Rider CBR Class B
	1584	RSVA - Retail Transmission Network Charge	2021		$437,610	$15,092	$452,702	Rate Rider Group 1
	1588	RSVA - Power (excluding Global Adjustment)	2021		($1,153,382)	($34,574)	($1,187,956)	Rate Rider Group 1
	1589	RSVA - Global Adjustment	2021		($81,104)	$7,225	($73,879)	Rate Rider RSVA Global Adjustment
	1595	Disposition and Recovery/Refund of Regulatory Balances (2018)	2021	$28,999			$0	no disposition
	1595	Disposition and Recovery/Refund of Regulatory Balances (2019)	2021	($24,485)			$0	no disposition
	1595	Disposition and Recovery/Refund of Regulatory Balances (2021)	2021	$228,535			$0	no disposition
		Total Group 1			($575)	$11,999	$11,424	
	USofA Account Number	Account Name	Balances Claimed	DVA Balances not being disposed	Principal Claim	Interest Claim	Total Claim	Disposition Method
Group 2	1508	Pole Attchment Revenue Variance	2022		$68,309	$1,024	$69,334	Rate Rider Group 2
	1508	Incremental Capital Rate Rider True Up (Sub 16)	to April 30, 2023		($179,238)	$1,819	($177,419)	Rate Rider Group 2
	1508	Incremental Capital Rate Rider True Up (SSG)	to April 30, 2023		($485,488)	$0	($485,488)	Rate Rider Group 2
	1509	COVID-19 Foregone Revenue - IRM May 1 2020 Delayed Rate Implementation Rate Rider True Up	to October 31, 2022		($1,869)	($60)	($1,929)	Rate Rider Group 2
	1509	Impacts Arising from the COVID-19 Emergency11	2021		$306,137	$20,005	$326,142	Rate Rider 1509 COVID
	1518	Retail Cost Variance Account - Retail6	2021		($17,380)	($1,472)	($18,852)	Rate Rider Group 2
	1548	Retail Cost Variance Account - STR6	2021		$61,455	$4,343	$65,798	Rate Rider Group 2
	1568	LRAM Variance Account4	2021		$165,614	$32,575	$198,189	Rate Rider LRAMVA
	1592	PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes12	2022	($619,378)				disposition through tax loss carry forward rate rider
		Total Group 2			($82,460)	$58,234	($24,225)	

Table 4.2B
Proposed Rate Riders

Group 1 Accounts (12mths)				
Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Group 1 Balance (excluding 1589)**	**Rate Rider for Deferral/ Variance Accounts**
RESIDENTIAL SERVICE	kWh	282,922,375	$68,175	0.0002
GENERAL SERVICE LESS THAN 50 KW SERVICE	kWh	86,539,469	$23,850	0.0003
GENERAL SERVICE 50 TO 999 KW SERVICE	kW	575,372	$68,773	0.1195
UNMETERED SCATTERED LOAD SERVICE	kWh	878,528	$260	0.0003
STREET LIGHTING SERVICE	kW	7,200	$727	0.1010
SENTINEL LIGHTING SERVICE	kW	566	$57	0.1012
Total			**$161,842**	

Account 1580, Sub-account CBR Class B (12mths)				
Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Sub-account 1580 CBR Class B Balance**	**Rate Rider for Sub-account 1580 CBR Class B**
RESIDENTIAL SERVICE	kWh	282,922,375	($38,136)	($0.0001)
GENERAL SERVICE LESS THAN 50 KW SERVICE	kWh	86,539,469	($11,665)	($0.0001)
GENERAL SERVICE 50 TO 999 KW SERVICE	kW	486,606	($26,263)	($0.0540)
UNMETERED SCATTERED LOAD SERVICE	kWh	878,528	($118)	($0.0001)
STREET LIGHTING SERVICE	kW	7,200	($332)	($0.0461)
SENTINEL LIGHTING SERVICE	kW	566	($26)	($0.0462)
Total			**($76,540)**	

RSVA Global Adjustment (12mths)				
Rate Class (Enter Rate Classes in cells below)	**Units**	**kWh**	**Allocated Global Adjustment Balance**	**Rate Rider for RSVA - Power - Global Adjustment**
RESIDENTIAL SERVICE	kWh	3,464,299	($1,498)	($0.0004)
GENERAL SERVICE LESS THAN 50 KW SERVICE	kWh	13,210,191	($5,710)	($0.0004)
GENERAL SERVICE 50 TO 999 KW SERVICE	kWh	151,901,265	($65,664)	($0.0004)
UNMETERED SCATTERED LOAD SERVICE	kWh	-	$0	
STREET LIGHTING SERVICE	kWh	2,330,282	($1,007)	($0.0004)
SENTINEL LIGHTING SERVICE	kWh	-	$0	
Total			**($73,879)**	

Group 2 Accounts (12mths)				
Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Group 2 Balance**	**Rate Rider for Group 2 Accounts**
RESIDENTIAL SERVICE	# of Customers	30,340	($235,082)	($0.65)
GENERAL SERVICE LESS THAN 50 KW SERVICE	kWh	86,539,469	($80,612)	($0.0009)
GENERAL SERVICE 50 TO 999 KW SERVICE	kW	575,372	($239,321)	($0.4159)
UNMETERED SCATTERED LOAD SERVICE	kWh	878,528	($800)	($0.0009)
STREET LIGHTING SERVICE	kW	7,200	$6,997	$0.9718
SENTINEL LIGHTING SERVICE	kW	566	$260	$0.4597
Total			**($548,557)**	

Account 1568 LRAMVA (12mths)				
Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Account 1568 Balance**	**Rate Rider for Account 1568**
RESIDENTIAL SERVICE	kWh	282,922,375	$44,507	$0.0002
GENERAL SERVICE LESS THAN 50 KW SERVICE	kWh	86,539,469	($110,221)	($0.0013)
GENERAL SERVICE 50 TO 999 KW SERVICE	kW	575,372	$263,903	$0.4587
UNMETERED SCATTERED LOAD SERVICE	kWh	878,528	$0	$0.0000
STREET LIGHTING SERVICE	kW	7,200	$0	$0.0000
SENTINEL LIGHTING SERVICE	kW	566	$0	$0.0000
Total			**$198,189**	

Account 1509 COVID (12mths)				
Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Account 1509 Balance**	**Rate Rider for Account 1509**
RESIDENTIAL SERVICE	# of Customers	30,340	$197,337	$0.54
GENERAL SERVICE LESS THAN 50 KW SERVICE	# of Customers	3,400	$49,992	$1.23
GENERAL SERVICE 50 TO 999 KW SERVICE	# of Customers	344	$73,771	$17.87
UNMETERED SCATTERED LOAD SERVICE	# of Customers	25	$645	$2.15
STREET LIGHTING SERVICE	# of Customers	8,037	$3,819	$0.04
SENTINEL LIGHTING SERVICE	# of Customers	317	$576	$0.15
Total			**$326,141**	

Table 4.2C
Deferral and Variance Accounts to Continue/Discontinue as of May 1, 2023

Account Description	UsofA	Commence / Continue/ Discontinue
Other Regulatory Assets - Sub Account - Incremental VVO Savings or Costs	1508	Commence
Other Regulatory Assets - Sub Account - EPC Contract Liquidated Damages	1508	Commence
Other Regulatory Assets - Sub Account - SSG Project Recovery Mechanism	1508	Commence
Pole Attachment Variance	1508	Continue
Other Regulatory Assets - Sub-Accounts - ICM Substation 16	1508	Discontinue
Other Regulatory Assets - Sub-Accounts - ICM SSG	1508	Discontinue
Impacts Arising from the COVID-19 Emergency	1509	Discontinue
Retail Cost Variance Account - Retail	1518	Discontinue
Retail Cost Variance Account - STR	1548	Discontinue
LRAM Variance Account	1568	Continue
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes	1592	Continue

Evidence:

Application: Exhibit 1 Section 1.2.7, Section 1.10; Exhibit 2 Section 2.8, Exhibit 3 Section 3.1.2 and Exhibit 9 in its entirety

IRRs: 2-Staff-19, 2-Staff-20, 2-Staff-29, 4-Staff-64, 4-Staff-81 through 4-Staff-83, 6-Staff-88, 6-Staff-89, 9-Staff-102 through 9-Staff-111; VECC-52 through VECC-54; SEC-9, SEC-16, SEC-24, SEC-25, SEC-34, and SEC-36;
Appendix IR5 2023 COS Accounting Order – SSG VVO Linkage

Appendices to this Settlement Proposal:
Appendix G 2023 COS Accounting Order – SSG VVO Linkage

Appendix H 2023 COS Accounting Order – SSG Liquidated Damages
Appendix I 2023 COS Accounting Order – SSG Custom IR Rate Rider Revenue

Settlement Models:
PUC_2023_DVA_Continuity_Schedule_SETTLEMENT_FINAL;
PUC_2023_GA_Analysis_Workform_SETTLEMENT_FINAL;

Clarification Responses: 6-Staff-127, 9-Staff-129 through 9-Staff-133; SEC-8; Appendix F – 2023 DVA Accounting Order – SSG Foregone Revenue

Supporting Parties: All

Parties Taking No Position: None.

4.3 *Is the proposed rate rider for the refund of Tax Loss Carry Forwards appropriate?*

Complete Settlement: The Parties agree that the cumulative impact of accelerated CCA (including the impact from 2022 projected SSG assets additions of $9,026,457 as noted below) as at December 31, 2022 that would have been recorded in Account 1592, Sub-account CCA Changes is captured in the total Tax Loss Carry Forwards instead of Account 1592. The Parties also agreed to refund the revenue requirement impact of the Tax Loss Carry Forwards through a rate rider.

PUC's projected tax loss carry forwards at the end of 2022 bridge year is $1,209,270 as shown in Table 4.3A below. This amount is then adjusted for the two ICMs that PUC completed in 2021 for Substation 16 and 2022 for the SSG project.

The 2021 ICM for Substation 16 came into service in 2021 and therefore formed part of PUC's capital additions in 2021 that was included in its 2021-year end tax returns. Therefore, the full accelerated CCA for Substation 16 is captured in PUC's 2022 projected loss carry forwards total of $1,209,270. Since PUC completed a true up calculation in which $155,790 of CCA in each of 2021 and 2022 is included in the computation of the ICM true up calculation, this amount needs to be a deduction from the $1,209,270 as shown in the table 4.3A below.

The 2022 tax loss carry-forward of $1,209,270 excludes the impact of the CCA from the SSG Project. PUC estimated that $9,026,457 of SSG Project asset additions would be completed in 2022, and would result in accelerated CCA deductions of $1,083,175. Of this amount, $361,058 was included in the calculation of PILs in the SSG ICM true-up, and the remaining $722,117 is to be included in the Tax Loss Carry Forwards, as shown in Table 4.3A. Table 4.3B summarizes the calculation relating to SSG Project CCA.

Table 4.3A: Tax Loss Carry Forwards

	2022 Year End Tax Los Carry Forwards	Sub 16 Adjustment	SSG adjustment	Total
Total Loss Carryforward	$ 1,209,270	$ (311,580)	$ 722,117	$ 1,619,807
Tax Rate	26.5%	26.5%	26.5%	26.5%
Tax Impact	$ 320,457	$ (82,569)	$ 191,361	$ 429,249
Benefit To Customers (Grossed Up)	$ 435,995	$ (112,338)	$ 260,355	$ 584,012

Table 4.3B: 2022 SSG Additions included in Tax Loss Carry Forward Rate Rider

Description	Amount
2022 estimated SSG Asset Additions	$ 9,026,457
Accelerated CCA	$ 1,083,175
Normal CCA (amount used in SSG ICM true up calculation)	$ 361,058
Difference (amount included in tax los carry forwards)	$ 722,117

Table 4.3C Tax Loss Carry Forward Rate Rider

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Account Tax Loss Carry Forwards	Rate Rider for Tax Loss Carry Forwards
RESIDENTIAL SERVICE	# of Customers	30,340	($358,423)	($0.98)
GENERAL SERVICE LESS THAN 50 KW SERVICE	kWh	86,539,469	($88,343)	($0.0010)
GENERAL SERVICE 50 TO 999 KW SERVICE	kW	575,372	($128,890)	($0.2240)
UNMETERED SCATTERED LOAD SERVICE	kWh	878,528	($1,178)	($0.0013)
STREET LIGHTING SERVICE	kW	7,200	($6,162)	($0.8559)
SENTINEL LIGHTING SERVICE	kW	566	($1,015)	($1.7931)
Total			**($584,012)**	

Evidence:

Application: Exhibit 6 Section 6.2

IRRs: 6-Staff-88, 6-Staff-89, SEC-34

Appendices to this Settlement Proposal: None.

Settlement Models:
2023_Tariff_Schedule_and_Bill_Impact_Model_SETTLEMENT_FINAL
PUC_2023_Test_year_Income_Tax_PILs_SETTLEMENT_FINAL

Clarification Responses: None

Supporting Parties: All
Parties Taking No Position: None.

5.0 Other

5.1 *Is the proposed effective date (i.e. May 1, 2023) for 2023 rates appropriate?*

Complete Settlement: The Parties agree that the effective date of May 1, 2023 for 2023 rates is appropriate. Should the Decision and Rate Order not be received by May 1, 2023, PUC would be permitted to recover such lost revenue between May 1, 2023 and the implementation date, if required.

Evidence:

Application: Exhibit 1 Section 1.3.8

IRRs: None

Appendices to this Settlement Proposal: None

Settlement Models: None

Clarification Responses: None

Supporting Parties: All

Parties Taking No Position: None.

5.2 *Are the amounts proposed for inclusion in rate base for the Incremental Capital Module approved in EB-2019-0170 and the proposed treatment of the associated true-up appropriate?*

Complete Settlement: The Parties agree that the amounts proposed for inclusion in rate base for the Incremental Capital Module approved in EB-2019-0170 and the proposed treatment of the associated true-up are appropriate.

Table 5.2A
Addition of ICM Assets to Rate Base
(Substation 16 – EB-2019-0170)

Accounts	Description	Additions 2021	Accumulated Amortization as of December 31, 2022	Net Book Value December 31, 2022
1820	Substation 16	$6,020,119	$225,754	$5,794,365

Table 5.2B
ICM True-Up Calculations
(Substation 16 – EB-2019-0170)

	ICM Decision	2020 Year End	2021 Year End	2022	
Capital Expenditures	$9,100,376	$0	$10,392,266	$10,392,266	
Reduction for Materiality Threshold	$6,497,525	$0	$6,497,525	$6,497,525	
Maximum Eligible Amount	$2,602,851		$1,947,371	$3,894,741	

	ICM Decision	2020 Year End	2021 Year End	2022	
Depreciation Expenses	$117,206	$0	$150,503	$150,503	
Maximum Eligible Amount	$64,521	$0	$48,684	$97,369	
PILS Impact	$19,090	$0	-$13,656	$28,857	
Return	$154,205	$0	$115,359	$230,717	
Incremental Revenue Requirement	**$237,816**	**$0**	**$150,387**	**$356,943**	

	ICM Decision	2020 Year End	2021 Year End (half year)	2022	Total
Rate Rider Revenues Actual/Projected		$48,855	$280,120	$357,594	$686,569
Incremental Revenue Requirement		$0	$150,387	$356,943	$507,330
Variance		($48,855)	($129,733)	($651)	($179,239)

Evidence:

Application: Exhibit 1 Section 1.2.3, Exhibit 2 Section 2.2 and 2.8

IRRs: 2-Staff-13, 2-Staff-14, 2-Staff-17 through 2-Staff-20, 2-Staff-24 through 2-Staff-29; VECC-2 through VECC-9, VECC-54; CCC-16, CCC-17; SEC-7, SEC-9 and SEC-10

Appendices to this Settlement Proposal:
Appendix B – Updated Appendix 2-AB: Capital Expenditure Summary

Settlement Models:

PUC_2023_DVA_Continuity_Schedule_SETTLEMENT_FINAL

Clarification Responses: 2-Staff-119, 2-Staff-120, 9-Staff-130; SEC-2, CCC-55

Supporting Parties: All

Parties Taking No Position: None.

5.3 *Are the amounts proposed for inclusion in rate base for the Incremental Capital Module approved in EB-2018-0219/EB-2020-0249 and the proposed treatment of the associated true-up appropriate?*

Complete Settlement:
As part of the pre-settlement clarification responses, PUC revised its 2022 SSG Project cost estimate due to the delay in completion of the project. As set out below, the Parties have agreed to the revised value for the SSG Project, comprised of 2022 net book value and 2023 capital additions, that until its next rebasing application will be recovered outside of base rates through the SSG Project Recovery Mechanism.

Table 5.3A
Addition of ICM Assets to SSG Rate Base
(Sault Smart Grid – EB-2018-0219/EB-2020-0249)

Accounts	Description	Additions 2022	Accumulated Amortization as of December 31, 2022	Net Book Value December 31, 2022
1820	Distribution Station Equipment	$8,702,746	$108,784	$8,593,962
1830	Poles, Towers and Fixtures	$461,127	$5,124	$456,003
1835	Overhead Conductors and Devices	$893,956	$7,450	$886,506
1845	Underground Conductors and Devices	$431,751	$5,397	$426,354
1850	Line Transformers	$155,030	$1,938	$153,092
1980	System Supervisory Equipment	$1,472,423	$36,811	$1,435,612
2440	Contributions and Grants	($3,090,576)	($38,632)	($3,051,944)
Total		**$9,026,456**	**$126,871**	**$8,899,586**
Accounts	**Description**	**2023 Additions**	**Accumulated Amortization as of December 31, 2023**	**Net Book Value December 31, 2023**
1820	Distribution Station Equipment	$14,211,278	$503,994	$22,410,030
1830	Poles, Towers and Fixtures	$753,003	$23,738	$1,190,392
1835	Overhead Conductors and Devices	$1,459,798	$34,514	$2,319,240
1845	Underground Conductors and Devices	$705,033	$25,004	$1,111,780
1850	Line Transformers	$253,158	$8,978	$399,210
1980	System Supervisory Equipment	$2,404,415	$170,542	$3,706,296
2440	Contributions and Grants	($4,264,862)	($169,207)	($7,186,231)
Total		**$15,521,823**	**$597,562**	**$23,950,718**

Table 5.3B below shows the ICM True-up Calculations for the SSG Project and the differences in amounts between the ICM decision EB-2018-0219/EB-2020-0249, Application and Interrogatories and the amounts agreed to by the Parties during settlement. A large portion of the 2022 capital work is being completed in 2023, it has resulted in a $485,488 refund to customers for the ICM true-up calculation.

Table 5.3B
ICM True-Up Calculations
(Sault Smart Grid – EB-2018-0219/EB-2020-0249)

	ICM Decision (half year)	Application & Interrogatories	Settlement: 2022 year End (half year)
Capital Expenditures	$33,495,218	$29,972,849	$17,641,397
Reduction for Materiality Threshold	$5,414,316	$5,414,316	$5,414,316
Maximum Eligible Amount	$28,080,902	$24,558,533	$12,227,081
	ICM Decision (half year)	**Application & Interrogatories**	**Settlement: 2022 year End (half year)**
Depreciation Expenses	$695,799	$600,448	$253,741
Maximum Eligible Amount	$347,900	$300,224	$126,871
PILS Impact	($206,565)	($63,115)	($26,678)
Return	$734,276	$631,604	$266,934
Incremental Revenue Requirement	**$875,611**	**$868,713**	**$367,126**
	ICM Decision	**Application & Interrogatories**	**Settlement: 2022 year End (half year)**
Rate Rider Revenues Actual/Projected		$852,614	$852,614
Incremental Revenue Requirement		$868,713	$367,126
Variance		$16,099	($485,488)

Sault Smart Grid Project Recovery Mechanism ("SSG Project Recovery Mechanism")

On April 29, 2021, PUC received approval from the OEB for the amended and restated Incremental Capital Module ("ICM") application for new rates effective May 1, 2022 in EB-2020-0249/EB-2018-0219. The Sault Smart Grid Project ("SSG Project") is a proposed community wide smart grid which will cover PUC's entire service territory. The SSG Project is expected to transform PUC's entire distribution system through an integrated project implementing various technologies such as Voltage/VAR Optimization, Distribution Automation and Advanced Metering Infrastructure.

The SSG Project carries a total net capital spend of $24.5 million and represents approximately 1/4th of PUC's total rate base. The SSG Project was initially expected to be fully completed and in service by December 31, 2022, however due to unforeseen circumstances[2] PUC updated the estimate of project spending during the pre-settlement clarification responses which outlined a net project spend of $9M in 2022 and the remaining $15.5M in 2023. The 2023 SSG Project additions represents 14.6% of PUC's average net fixed assets.

In its pre-settlement clarification responses, PUC also brought forth an SSG Foregone Revenue Requirement Accounting Order intended to make PUC whole for the revenue requirement on the $15.5 million of 2023 SSG additions due to application of the half-year rule to additions placed in service in the test year. Without the proposed account, PUC noted that it would be foregoing revenue requirement each year which could put the utility in an under earnings situation beginning in 2024 and substantially impair its cash flow. The Parties agreed that some form of mechanism was required to help PUC make up some of the shortfall in revenue requirement as a result of the SSG Project delay given its size and the fact the OEB has approved the project.

The SSG Project Recovery Mechanism is of unprecedented nature and one of a kind considering the large value the SSG Project itself, which was previously approved as ICM in EB-2020-0249/EB-2018-0219. The Parties agreed that the SSG Project Recovery Mechanism is not meant to be precedent and is being agreed to in the context of a full settlement, and is appropriate because of the SSG Project size, unique circumstances related to the project delay, and the previous approvals in EB-2020-0249/EB-2018-0219.

As noted above, it was agreed upon between PUC and intervenors that some mechanism was required to allow PUC to recover the revenue requirement for the $15.5 million 2023 investment in the SSG Project as a result of delays PUC incurred in completing all SSG capital additions in 2022. The Parties agreed to the SSG Project Recovery Mechanism, which removes the entire SSG Project (comprised of 2022 net book value and 2023 capital additions) from PUC's rate base and calculates separate rate riders to recover the SSG revenue requirement until rebasing in 2028. The SSG Model shows the revenue requirement components including depreciation, PILs with the associated CCA (excluding 2022 CCA on 2022 additions which has been captured in the tax loss carry forwards and the ICM true-up calculation), and Return on Rate Base. The model then uses the 2023 Cost of Service Rate Application information (as adjusted by any relevant agreed upon changes in this settlement proposal) to allocate revenue requirement to each rate class and the same Fixed/Variable split for calculating the rate riders to be collected from customers. The following describes each component in detail.

1) SSG Project In Service Additions – For the purposes of calculating the rate rider, PUC will use a net project spend of $9,026,457 for 2022 in service additions and $15,521,823 for 2023 in service additions.

2) Depreciation – A straight line method is used for calculating depreciation which is in line with current PUC practices. 2023 Depreciation will be on a half year basis for the 2023 in service additions and full year basis for the 2022 in-service additions. In years 2024-2027 depreciation is

[2] For further explanation, please refer to Pre-Settlement Clarification Question CCC-55 in Appendix F.

set at an amount of $687,641/year. The depreciation total is net of amortization of contributed capital.

3) CCA - The CCA calculation tab calculates actual CCA in each respective year to reflect the amount of CCA that PUC would deduct from its taxable income on its tax return from 2022 (the first year where there is CCA on the SSG Project) to 2027. The 2022 CCA is excluded from the SSG Recovery Mechanism as it has been accounted for through other mechanisms. In 2022, PUC will deduct approximately $1,083,675 in CCA. Of this amount, $361,075 has already been included as a deduction in the PILs of the ICM true up calculation outlined above. The remaining $722,117 has been included in PUC's tax loss carry forward total that is to be refunded to customers as outlined in Issue 4.3 above. Therefore, the SSG Project Recovery Mechanism only considers the 2023 to 2027 PILs impact. Table E summarizes the total CCA for the SSG Project and where the amounts have been allocated.

Table E – CCA Calculation for SSG Project

Total CCA from 2022 to 2027	9,527,652
2022 CCA included in ICM True up	361,058
2022 CCA included in tax loss carry forward refund	722,117
Revised Total of CCA for SSG Project Recovery Mechanism	8,444,477
Smoothed Yearly	1,688,895

It has been agreed upon that the 2022-2027 aggregate of $8,444,477 will be smoothed across 2023-2027 to help balance the impacts of accelerated CCA.

4) Cost of Capital Parameters – The parties have agreed to use PUC's 2023 cost of capital parameters for calculating the return on rate base.

5) Incremental Revenue Requirement – The yearly incremental revenue requirement to calculate the basis of the rate rider is presented in Table F below.

Table F: Yearly Revenue Requirement[1]

Incremental Revenue Requirement	2023	2024	2025	2026	2027
Return on Rate Base - Total	$ 1,042,866	$ 1,498,849	$ 1,455,189	$ 1,411,530	$ 1,367,870
Amortization Expense - Total	$ 470,691	$ 687,641	$ 687,641	$ 687,641	$ 687,641
Grossed-Up Taxes/PILs	$ (217,497)	$ (42,332)	$ (51,615)	$ (60,897)	$ (70,179)
Incremental Revenue Requirement with CCA	$ 1,296,060	$ 2,144,158	$ 2,091,216	$ 2,038,274	$ 1,985,332

1 – The calculation of 2024-2027 revenue requirement will change once the SSG Project actual spending is reconciled.

6) Rate Design – PUC is proposing to collect SSG revenue requirement from customers in the same proportion as distribution revenue collected as from customers pursuant to the Settlement Proposal. The percentage allocations are shown in the Table G below reflect the as settled revenue requirement percentages that are applicable to the SSG Project.

Table G – Rate Design

Customer Class	Rev Requirement %
Residential	60.2%
GS < 50 kW	15.8%
GS >50 to 4,999 kW	22.6%
Street Lighting	1.0%
Sentinel Lighting	0.2%
Unmetered and Scattered	0.2%
Total	100.0%

7) Fixed/Volumetric Split – PUC is proposing a fixed/volumetric split that matches the splits agreed to in this Settlement Proposal for distribution revenue, as presented in Table H below for the 2023 Rate Year

Table H – Fixed/Volumetric Split

2023

Customer Class	Current Volumetric Split	Current Fixed Charge Split	Volumetric Revenue	Fixed Revenue
Residential	0%	100%	$ 45	$ 779,792
GS < 50 kW	75%	25%	$ 154,073	$ 50,854
GS >50 to 4,999 kW	90%	10%	$ 264,746	$ 28,416
Street Lighting	33%	67%	$ 4,398	$ 9,009
Sentinel Lighting	58%	42%	$ 1,284	$ 924
Unmetered and Scattered	91%	9%	$ 2,335	$ 229
Total			$ 426,880	$ 869,224

2024

Customer Class	Current Volumetric Split	Current Fixed Charge Split	Volumetric Revenue	Fixed Revenue
Residential	0%	100%	$ 74	$ 1,290,062
GS < 50 kW	75%	25%	$ 254,894	$ 84,131
GS >50 to 4,999 kW	90%	10%	$ 437,986	$ 47,011
Street Lighting	33%	67%	$ 7,276	$ 14,904
Sentinel Lighting	58%	42%	$ 2,124	$ 1,528
Unmetered and Scattered	91%	9%	$ 3,862	$ 379
Total			$ 706,216	$ 1,438,016

2025

Customer Class	Current Volumetric Split	Current Fixed Charge Split	Volumetric Revenue	Fixed Revenue
Residential	0%	100%	$ 72	$ 1,258,209
GS < 50 kW	75%	25%	$ 248,600	$ 82,054
GS >50 to 4,999 kW	90%	10%	$ 427,172	$ 45,850
Street Lighting	33%	67%	$ 7,096	$ 14,536
Sentinel Lighting	58%	42%	$ 2,072	$ 1,491
Unmetered and Scattered	91%	9%	$ 3,767	$ 370
Total			$ 688,778	$ 1,402,509

2026

Customer Class	Current Volumetric Split	Current Fixed Charge Split	Volumetric Revenue	Fixed Revenue
Residential	0%	100%	$ 70	$ 1,226,356
GS < 50 kW	75%	25%	$ 242,306	$ 79,976
GS >50 to 4,999 kW	90%	10%	$ 416,357	$ 44,689
Street Lighting	33%	67%	$ 6,916	$ 14,168
Sentinel Lighting	58%	42%	$ 2,020	$ 1,453
Unmetered and Scattered	91%	9%	$ 3,672	$ 360
Total			$ 671,341	$ 1,367,003

2027

Customer Class	Current Volumetric Split	Current Fixed Charge Split	Volumetric Revenue	Fixed Revenue
Residential	0%	100%	$ 68	$ 1,194,502
GS < 50 kW	75%	25%	$ 236,013	$ 77,899
GS >50 to 4,999 kW	90%	10%	$ 405,543	$ 43,529
Street Lighting	33%	67%	$ 6,737	$ 13,800
Sentinel Lighting	58%	42%	$ 1,967	$ 1,415
Unmetered and Scattered	91%	9%	$ 3,576	$ 351
Total			$ 653,904	$ 1,331,496

7) Billing Determinants / Rate Rider Calculation – PUC is proposing to use the billing determinants agreed to in this Settlement Proposal for distribution revenue, as presented in Table I below for the 2023 rate year. The rate riders will be updated annually in accordance with Table I below to reflect the annual revenue requirements calculated based on the project's forecasted costs as set out in the SSG Model.. .

Table I – Billing Determinants / Rate Rider Calculation

2023 (effective from May 1, 2023 to April 30, 2024)

	Billing Determinants				Rate Riders	
Customer Class	# of Customers	Consumption	unit		Fixed Rate	Volumetric Rate
Residential	30340	282,922,375			$ 2.14	0
GS < 50 kW	3400	86,539,469	kWh		$ 1.25	0.0018
GS >50 to 4,999 kW	344	575,372	kW		$ 6.88	0.4601
Street Lighting	8037	7,200	kW		$ 0.09	0.6108
Sentinel Lighting	317	566	kW		$ 0.24	2.2678
Unmetered and Scattered	25	878,528	kWh		$ 0.76	0.0027
Total						

2024 (effective from May 1, 2024 to April 30, 2025)

	Billing Determinants				Rate Riders	
Customer Class	# of Customers	Consumption	unit		Fixed Rate	Volumetric Rate
Residential	30340	282,922,375			$ 3.54	0
GS < 50 kW	3400	86,539,469	kWh		$ 2.06	0.0029
GS >50 to 4,999 kW	344	575,372	kW		$ 11.39	0.7612
Street Lighting	8037	7,200	kW		$ 0.15	1.0105
Sentinel Lighting	317	566	kW		$ 0.40	3.7518
Unmetered and Scattered	25	878,528	kWh		$ 1.26	0.0044
Total						

2025 (effective from May 1, 2025 to April 30, 2026)

	Billing Determinants					
Customer Class	# of Customers	Consumption	unit		Fixed Rate	Volumetric Rate
Residential	30340	282,922,375			$ 3.46	0
GS < 50 kW	3400	86,539,469	kWh		$ 2.01	0.0029
GS >50 to 4,999 kW	344	575,372	kW		$ 11.11	0.7424
Street Lighting	8037	7,200	kW		$ 0.15	0.9855
Sentinel Lighting	317	566	kW		$ 0.39	3.6592
Unmetered and Scattered	25	878,528	kWh		$ 1.23	0.0043
Total						

2026 (effective from May 1, 2026 to April 30, 2027)					
	Billing Determinants				
Customer Class	# of Customers	Consumption	unit	Fixed Rate	Volumetric Rate
Residential	30340	282,922,375		$ 3.37	0
GS < 50 kW	3400	86,539,469	kWh	$ 1.96	0.0028
GS >50 to 4,999 kW	344	575,372	kW	$ 10.83	0.7236
Street Lighting	8037	7,200	kW	$ 0.15	0.9606
Sentinel Lighting	317	566	kW	$ 0.38	3.5666
Unmetered and Scattered	25	878,528	kWh	$ 1.20	0.0042
Total					

2027 (effective from May 1, 2027 to April 30, 2028)					
	Billing Determinants				
Customer Class	# of Customers	Consumption	unit	Fixed Rate	Volumetric Rate
Residential	30340	282,922,375		$ 3.28	0
GS < 50 kW	3400	86,539,469	kWh	$ 1.91	0.0027
GS >50 to 4,999 kW	344	575,372	kW	$ 10.54	0.7048
Street Lighting	8037	7,200	kW	$ 0.14	0.9356
Sentinel Lighting	317	566	kW	$ 0.37	3.4739
Unmetered and Scattered	25	878,528	kWh	$ 1.17	0.0041
Total					

8) 2028 COS True up Calculation– The SSG Project Recovery Mechanism will be subject to an asymmetrical true-up mechanism for the period of May 1, 2023 to April 30, 2028, to the benefit of ratepayers, that will be tracked in the new variance account, Account 1508, Sub-account SSG Project Recovery Mechanism Variance Account. PUC's net recovery for the SSG Project during this period after considering this sub-account will be the lower of

a. total rate riders collected from May 1, 2023 to April 30, 2028

b. the sum of 2023 to 2027 revenue requirements, where the annual revenue requirement is the lower of i) the recalculated revenue requirement based on actual SSG Project capital costs and in-service dates, and ii) the settled forecasted revenue requirement used to calculate the SSG Recovery Mechanism Rate Rider.

The full details of the true up calculation is outlined in Accounting Order attached as Appendix I – 2023 Cost of Service Application – The Sault Smart Grid Project Recovery Mechanism Variance Account.

As the revenue requirement included in the SSG Project Recovery Mechanism is intended to allow recovery of the costs of the SSG Project set out in Table D.1 above, but through a different recovery mechanism than if the amount had been included in base rates, the Parties agree that PUC will make appropriate adjustments in its historical fixed assets continuity schedules so that the remaining net book value of the SSG Project related costs that should be added to PUC's rate base at its next rebasing is equal to the actual costs up to a maximum of the forecasted costs in Table D.1 under the Summary section. Any increase in costs from what has been forecasted in Table D.1, which will not be recovered through the SSG Project Recovery Mechanism, will be subject to a prudence review, if PUC seeks to add that additional amount to rate base at its next rebasing.

Evidence:

Application: Exhibit 1 Section 1.2.3, Exhibit 2 Section 2.2 and 2.8

IRRs: 2-Staff-13, 2-Staff-14, 2-Staff-17 through 2-Staff-20, 2-Staff-24 through 2-Staff-29; VECC-2 through VECC-9, VECC-54; CCC-16, CCC-17; SEC-7, SEC-9 and SEC-10

Appendices to this Settlement Proposal:
Appendix B – Updated Appendix 2-AB: Capital Expenditure Summary

Settlement Models:
PUC_2023_DVA_Continuity_Schedule_SETTLEMENT_FINAL

Clarification Responses: 2-Staff-119, 2-Staff-120, 9-Staff-130; SEC-2, CCC-55

Supporting Parties: All

Parties Taking No Position: None.

5.4 *Has PUC Distribution Inc. responded appropriately to the OEB's directions/orders from its stand-alone Incremental Capital Module application relating to the Sault Smart Grid Project (EB-2018-0219/EB-2020-0249)?*

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Agreement, the Parties agree that PUC responded appropriately to the OEB's directions and orders from its stand-alone Incremental Capital Module application relating to the SSG Project (EB-2018-0219/EB-2020-0249).

At page 38 of Exhibit 1 PUC summarized the list of commitments in relation to the SSG Project (EB-2018-0219/EB-2020-0249). The outstanding commitments that are addressed in this settlement proposal are are set out below in Table 5.4A

Table 5.4A: List of Outstanding Prior Commitments Related to SSG Project

	Action Item	File # and Reference	Completion
8	PUC Distribution shall provide a detailed report as part of its next rebasing application, which compares the SSG project costs, and benefits as implements to what was forecast in this application	EB-2020-0249 EB-2018-0219 pg. 24	PUC has updated the customer net benefit table and sensitivity analysis based on the most recently readily available information (COP rates, Cost of Capital Parameters) in the DSP as part of Section 5.3.6.2.2. This report will be filed on the record of this proceeding concurrent with commitment 10, namely within18 months after project completion. As detailed below, PUC will also provide a third-party report reviewing the VVO consumption savings methodology PUC has adopted.
9	PUC Distribution shall file all available information on the proposed Project performance metrics that it intends to track, along with proposed targets, in its next rebasing application. This shall include an appropriate metric and targets to symmetrically link the VVO performance of the Project to PUC's allowable ROE for this project.	EB-2020-0249 EB-2018-0219 pg. 11 & 24	The Parties accept the proposed performance metrics table within "Appendix H_Sault Smart Grid_Performance Metrics_OEB Order No. 6_20221026" filed October 26, 2023 included at Appendix J of this Settlement Proposal and the methodology for connecting the VVO Savings and PUC's allowable ROE set out in Appendix G of this Settlement Proposal. As detailed below, PUC will provide a third-party report reviewing the VVO consumption savings methodology PUC has adopted.
10	PUC Distribution shall post on its public website a report, within 18 months of Project completion, and with annual updates for 10 years thereafter which shows the actual benefits	EB-2020-0249 EB-2018-0219 pg. 24	The parties agreed PUC will post annual updates at the same time as RRR filing deadline of April 30th yearly. The first report will be provided within 18 months of project completion and then yearly by April 30th, thereafter.

	of the SSG Project, broken down by customer class.		
11	Any EPC Contract liquidated damages resulting from "performance" or "delay" shall be used to reduce the Project capital cost and would be settled at the time of the next rebasing	EB-2020-0249 EB-2018-0219 pg. 24	At this current time, there are no liquidated damages expected. If liquidated damages occur after the filing of this application, but before any decision is received, PUC is recommending revising the application information accordingly. If liquidated damages occur after the resulting decision, PUC is recommending the use of a DVA account to record the variance in revenue requirement as a result of the number of liquidated damages. The damages would be treated as contributed capital, thus reducing the net book value of the assets in rate base. The Parties agree that PUC responded appropriately to this OEB direction by creating the liquidated damages DVA as outlined in Appendix H.

PUC agrees to roll over commitment 8 and 10 in line with the timing of commitment 10, which is within 18 months after SSG Project completion.

In fulfilment of commitment 8, PUC will file a detailed report which compares the SSG project costs and benefits, as implemented, to what was forecast in the ICM application at the same time as commitment 10. This report will be filed on the record of this proceeding (EB-2022-0059).

PUC agrees to retain one or more independent third-parties to undertake a review of the VVO savings from the SSG Project, to be filed as part of commitment 9 and in PUC's next rebasing, that specifically includes:

(a) A review of the VVO consumption savings methodology PUC has adopted as outlined in the filing in OEB Proceeding EB-2022-0059 dated October 26, 2022 and titled "Appendix H_Sault Smart Grid_Performance Metrics_OEB Order No. 6_20221026" (the "on-off" methodology from IEEE 1885-2022), the other consumption savings methodologies included in IEEE 1885-2022, and any other generally accepted consumption savings methodologies that may exist, and report on whether the selected methodology is the most appropriate and why.

(b) Based on the methodology that PUC has adopted as outlined in the filing in OEB Proceeding EB-2022-0059 dated October 26, 2022 and titled "Appendix H_Sault Smart Grid_Performance Metrics_OEB Order No. 6_20221026" (the "on-off" methodology from IEEE 1885-2022), a review to determine if it has calculated the savings correctly.

(c) Using actual consumption data, a review to determine if the estimated savings based on the PUC methodology outlined in the filing in OEB Proceeding EB-2022-0059 dated October 26, 2022 and titled "Appendix H_Sault Smart Grid_Performance Metrics_OEB Order No. 6_20221026" (the "on-off" methodology from IEEE 1885-2022), reflects a reasonable level of actual savings for customers.

As part of Commitment 9 in Table 5.4A above from EB-2020-0249/EB-2018-0219, PUC was directed to file all available information on the SSG Project performance metrics that it intends to track, along with proposed targets, in this rebasing application. The OEB stated this shall include an appropriate metric and targets to symmetrically link the VVO performance of the SSG Project to PUC's allowable return on equity ("ROE") for the SSG Project.

The Parties agree to the creation of the new Account 1508, Sub-account Incremental VVO Savings or Costs for the calculation of the VVO savings to ROE linkage. If PUC achieves VVO savings that is above or below the target value of 2.70%, it will symmetrically collect or refund the percentage difference of its ROE on the SSG Project in that respective year in accordance with the detailed methodology set out in Accounting Order at Appendix G, including the discretion a future hearing panel has regarding account disposition.

Evidence:

Application: Exhibit 1 Section 1.3.10, Exhibit 2 Section 2.8, Exhibit 2 Appendix C – PUC Distribution System Plan Section 5.3.6; Exhibit 9 Appendix B – Accounting Order – Sault Smart Grid_Voltage_VAR Optimization Linkage to Return on Equity; Exhibit 9 Appendix C – Accounting Order – Sault Smart Grid_EPC Contract Liquidated Damages, "Appendix H_Sault Smart Grid_Performance Metrics_OEB Order No. 6_20221026" filed October 26, 2023

IRRs: 2-Staff-17, 2-Staff-18, 2-Staff-19, 2-Staff-25 through 2-Staff-29, 9-Staff-110 and 9-Staff-111; VECC-5 and VECC-6, SEC-16

Appendices to this Settlement Proposal: Appendix G – 2023 COS Accounting Order – SSG VVO Linkage, Appendix H – 2023 COS Accounting Order – SSG Liquidated Damages

Settlement Models: None

Clarification Responses: SEC-8, SEC-9

Supporting Parties: All

Parties Taking No Position: None.

Appendix A – Updated 2023 Revenue Requirement Work Form

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Version 1.00

Utility Name	PUC Distribution Inc.
Service Territory	*Sault Ste. Marie*
Assigned EB Number	Eb-2022-0059
Name and Title	Tyler Kasubeck, Regulatory Financial Analyst
Phone Number	705-987-2095
Email Address	tyler.kasubeck@ssmpuc.com
Test Year	2022
Bridge Year	2023
Last Rebasing Year	2018

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

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Notes:

(1) Pale green cells represent inputs

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

(3) Pale yellow cells represent drop-down lists

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Data Input [1]

		Initial Application [2]	Adjustments	Interrogatory Responses [6]	Adjustments	Per Board Decision
1	**Rate Base**					
	Gross Fixed Assets (average)	$166,892,585	$40,000	$ 166,932,585	($24,528,094)	$142,404,491
	Accumulated Depreciation (average)	($36,460,700) [5]	($7,522)	($36,468,222)	$661,795	($35,806,428)
	Allowance for Working Capital:					
	Controllable Expenses	$13,949,291	$101	$ 13,949,392	($553,395)	$13,395,997
	Cost of Power	$61,481,413	($1,090,400)	$ 60,391,013	$4,137,836	$64,528,849
	Working Capital Rate (%)	7.50% [9]	0.00%	7.50% [9]	0.00%	7.50% [9]
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$21,083,379	($49,172)	$21,034,207	$471,823	$21,506,030
	Distribution Revenue at Proposed Rates	$25,001,934	$910,923	$25,912,857	($2,709,095)	$23,203,762
	Other Revenue:					
	Specific Service Charges	$26,520	$0	$26,520	$0	$26,520
	Late Payment Charges	$230,292	$0	$230,292	($0)	$230,292
	Other Distribution Revenue	$2,365,053	$116,757	$2,481,810	($212,935)	$2,268,875
	Other Income and Deductions	$128,400	$0	$128,400	$0	$128,400
	Total Revenue Offsets	$2,750,265 [7]	$116,757	$2,867,022	($212,935)	$2,654,087
	Operating Expenses:					
	OM+A Expenses	$13,533,701		$ 13,533,701	($550,000)	$12,983,701
	Depreciation/Amortization	$5,425,413	$15,044	$ 5,440,457	($876,988)	$4,563,469
	Property taxes	$384,446		$ 384,446		$384,446
	Other expenses	$31,144	$101	31245	($3,395)	$27,850
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	($3,121,699) [3]	($74,441)	($3,196,140)	$1,106,311	($2,089,829)
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$421,994	$80,763	$502,756	$59,048	$561,805
	Income taxes (grossed up)	$574,141		$684,022		$764,360
	Federal tax (%)	15.00%	0.00%	15.00%	0.00%	15.00%
	Provincial tax (%)	11.50%	0.00%	11.50%	0.00%	11.50%
	Income Tax Credits	$ -	$0	$ -		
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%	0.00%	56.0%	0.00%	56.0%
	Short-term debt Capitalization Ratio (%)	4.0% [8]	0.00%	4.0% [8]	0.00%	4.0% [8]
	Common Equity Capitalization Ratio (%)	40.0%	0.00%	40.0%	0.00%	40.0%
	Prefered Shares Capitalization Ratio (%)					
		100.0%		100.0%		100.0%
	Cost of Capital					
	Long-term debt Cost Rate (%)	3.97%	0.43%	4.40%	(0.09%)	4.31%
	Short-term debt Cost Rate (%)	1.17%	3.62%	4.79%	0.00%	4.79%
	Common Equity Cost Rate (%)	8.66%	0.70%	9.36%	0.00%	9.36%
	Prefered Shares Cost Rate (%)					

Notes:

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

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

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

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

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

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

(6) Select option from drop-down list by clicking on cell M12. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

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

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$166,892,585	$40,000	$166,932,585	($24,528,094)	$142,404,491
2	Accumulated Depreciation (average)	(2)	($36,460,700)	($7,522)	($36,468,222)	$661,795	($35,806,428)
3	Net Fixed Assets (average)	(2)	$130,431,885	$32,478	$130,464,363	($23,866,300)	$106,598,063
4	Allowance for Working Capital	(1)	$5,657,303	($81,772)	$5,575,530	$268,833	$5,844,363
5	**Total Rate Base**		$136,089,188	($49,294)	$136,039,893	($23,597,467)	$112,442,427

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

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$13,949,291	$101	$13,949,392	($553,395)	$13,395,997
7	Cost of Power		$61,481,413	($1,090,400)	$60,391,013	$4,137,836	$64,528,849
8	Working Capital Base		$75,430,704	($1,090,299)	$74,340,405	$3,584,441	$77,924,846
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$5,657,303	($81,772)	$5,575,530	$268,833	$5,844,363

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$25,001,934	$910,923	$25,912,857	($2,709,095)	$23,203,762
2	Other Revenue	(1)	$2,750,265	$116,757	$2,867,022	($212,935)	$2,654,087
3	Total Operating Revenues		$27,752,199	$1,027,680	$28,779,879	($2,922,030)	$25,857,849
	Operating Expenses:						
4	OM+A Expenses		$13,533,701	$ -	$13,533,701	($550,000)	$12,983,701
5	Depreciation/Amortization		$5,425,413	$15,044	$5,440,457	($876,988)	$4,563,469
6	Property taxes		$384,446	$ -	$384,446	$ -	$384,446
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$31,144	$101	$31,245	($3,395)	$27,850
9	Subtotal (lines 4 to 8)		$19,374,704	$15,145	$19,389,849	($1,430,383)	$17,959,466
10	Deemed Interest Expense		$3,089,225	$523,451	$3,612,675	($683,325)	$2,929,350
11	Total Expenses (lines 9 to 10)		$22,463,929	$538,596	$23,002,524	($2,113,708)	$20,888,816
12	**Utility income before income taxes**		$5,288,271	$489,084	$5,777,355	($808,322)	$4,969,033
13	Income taxes (grossed-up)		$574,141	$109,881	$684,022	$80,338	$764,360
14	**Utility net income**		$4,714,130	$379,203	$5,093,333	($888,660)	$4,204,673

Notes

Other Revenues / Revenue Offsets

Note		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$26,520	$ -	$26,520	$ -	$26,520
	Late Payment Charges	$230,292	$ -	$230,292	($0)	$230,292
	Other Distribution Revenue	$2,365,053	$116,757	$2,481,810	($212,935)	$2,268,875
	Other Income and Deductions	$128,400	$ -	$128,400	$ -	$128,400
	Total Revenue Offsets	$2,750,265	$116,757	$2,867,022	($212,935)	$2,654,087

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$4,714,129	$5,093,334	$4,209,844
2	Adjustments required to arrive at taxable utility income	($3,121,699)	($3,196,140)	($2,089,829)
3	Taxable income	$1,592,430	$1,897,194	$2,120,015
	Calculation of Utility income Taxes			
4	Income taxes	$421,994	$502,756	$561,805
6	Total taxes	$421,994	$502,756	$561,805
7	Gross-up of Income Taxes	$152,147	$181,266	$202,555
8	Grossed-up Income Taxes	$574,141	$684,022	$764,360
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$574,141	$684,022	$764,360
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Revenue Requirement Workform (RRWF) for 2023 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$76,209,945	3.97%	$3,025,535
2	Short-term Debt	4.00%	$5,443,568	1.17%	$63,690
3	**Total Debt**	60.00%	$81,653,513	3.78%	$3,089,225
	Equity				
4	Common Equity	40.00%	$54,435,675	8.66%	$4,714,129
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$54,435,675	8.66%	$4,714,129
7	**Total**	100.00%	$136,089,188	5.73%	$7,803,354
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$76,182,340	4.40%	$3,352,023
2	Short-term Debt	4.00%	$5,441,596	4.79%	$260,652
3	**Total Debt**	60.00%	$81,623,936	4.43%	$3,612,675
	Equity				
4	Common Equity	40.00%	$54,415,957	9.36%	$5,093,334
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$54,415,957	9.36%	$5,093,334
7	**Total**	100.00%	$136,039,893	6.40%	$8,706,009
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$62,967,759	4.31%	$2,713,910
9	Short-term Debt	4.00%	$4,497,697	4.79%	$215,440
10	**Total Debt**	60.00%	$67,465,456	4.34%	$2,929,350
	Equity				
11	Common Equity	40.00%	$44,976,971	9.36%	$4,209,844
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$44,976,971	9.36%	$4,209,844
14	**Total**	100.00%	$112,442,427	6.35%	$7,139,195

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$3,918,555		$4,878,651		$1,702,903
2	Distribution Revenue	$21,083,379	$21,083,379	$21,034,207	$21,034,206	$21,506,030	$21,500,859
3	Other Operating Revenue Offsets - net	$2,750,265	$2,750,265	$2,867,022	$2,867,022	$2,654,087	$2,654,087
4	**Total Revenue**	$23,833,644	$27,752,199	$23,901,229	$28,779,879	$24,160,117	$25,857,849
5	Operating Expenses	$19,374,704	$19,374,704	$19,389,849	$19,389,849	$17,959,466	$17,959,466
6	Deemed Interest Expense	$3,089,225	$3,089,225	$3,612,675	$3,612,675	$2,929,350	$2,929,350
8	**Total Cost and Expenses**	$22,463,929	$22,463,929	$23,002,524	$23,002,524	$20,888,816	$20,888,816
9	**Utility Income Before Income Taxes**	$1,369,716	$5,288,271	$898,705	$5,777,355	$3,271,301	$4,969,033
10	Tax Adjustments to Accounting Income per 2013 PILs model	($3,121,699)	($3,121,699)	($3,196,140)	($3,196,140)	($2,089,829)	($2,089,829)
11	**Taxable Income**	($1,751,984)	$2,166,571	($2,297,435)	$2,581,215	$1,181,472	$2,879,204
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	($464,276)	$574,141	($608,820)	$684,022	$313,090	$762,989
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$1,833,991	$4,714,130	$1,507,525	$5,093,333	$2,958,211	$4,204,673
16	**Utility Rate Base**	$136,089,188	$136,089,188	$136,039,893	$136,039,893	$112,442,427	$112,442,427
17	Deemed Equity Portion of Rate Base	$54,435,675	$54,435,675	$54,415,957	$54,415,957	$44,976,971	$44,976,971
18	Income/(Equity Portion of Rate Base)	3.37%	8.66%	2.77%	9.36%	6.58%	9.35%
19	Target Return - Equity on Rate Base	8.66%	8.66%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-5.29%	0.00%	-6.59%	0.00%	-2.78%	-0.01%
21	Indicated Rate of Return	3.62%	5.73%	3.76%	6.40%	5.24%	6.34%
22	Requested Rate of Return on Rate Base	5.73%	5.73%	6.40%	6.40%	6.35%	6.35%
23	Deficiency/Sufficiency in Rate of Return	-2.12%	0.00%	-2.64%	0.00%	-1.11%	0.00%
24	Target Return on Equity	$4,714,129	$4,714,129	$5,093,334	$5,093,334	$4,209,844	$4,209,844
25	Revenue Deficiency/(Sufficiency)	$2,880,138	$0	$3,585,808	($1)	$1,251,634	($5,172)
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,918,555 (1)		$4,878,651 (1)		$1,702,903 (1)	

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision
1	OM&A Expenses	$13,533,701		$13,533,701		$12,983,701
2	Amortization/Depreciation	$5,425,413		$5,440,457		$4,563,469
3	Property Taxes	$384,446		$384,446		$384,446
5	Income Taxes (Grossed up)	$574,141		$684,022		$764,360
6	Other Expenses	$31,144		$31,245		$27,850
7	Return					
	Deemed Interest Expense	$3,089,225		$3,612,675		$2,929,350
	Return on Deemed Equity	$4,714,129		$5,093,334		$4,209,844
8	**Service Revenue Requirement (before Revenues)**	$27,752,199		$28,779,880		$25,863,021
9	Revenue Offsets	$2,750,265		$2,867,022		$2,654,087
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$25,001,934		$25,912,858		$23,208,934
11	Distribution revenue	$25,001,934		$25,912,857		$23,203,762
12	Other revenue	$2,750,265		$2,867,022		$2,654,087
13	**Total revenue**	$27,752,199		$28,779,879		$25,857,849
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	($1)	(1)	($5,172) (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Interrogatory Responses	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$27,752,199	$28,779,880	**3.70%**	$25,863,021	#####
Grossed-Up Revenue Deficiency/(Sufficiency)	$3,918,555	$4,878,651	#####	$1,702,903	#####
Base Revenue Requirement (to be recovered from Distribution Rates)	$25,001,934	$25,912,858	**3.64%**	$23,208,934	#####
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$3,918,555	$4,878,650	#####	$1,697,732	#####

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Load Forecast Summary

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

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

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

Stage in Process: Per Board Decision

	Customer Class	**Initial Application**			**Interrogatory Responses**			**Per Board Decision**		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual
1	Residential	30,340	274,738,681		30,340	273,629,866		30,340	282,922,375	
2	GS<50	3,400	79,051,528		3,400	78,837,024		3,400	86,539,469	
3	GS>50	344	221,450,388	547,687	344	219,167,959	542,043	344	232,644,288	575,372
4	Sentinel	317	193,841	566	317	193,841	566	317	193,841	566
5	Street Lights	8,037	2,459,994	7,200	8,037	2,459,994	7,200	8,037	2,459,994	7,200
6	Unmetered Scattered Load	25	878,528		25	878,528		25	878,528	
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**578,772,961**	**555,454**		**575,167,213**	**549,809**		**605,638,496**	**583,138**

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Cost Allocation and Rate Design

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

Stage in Application Process: ***Per Board Decision***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 11,226,807	58.50%	$ 16,370,328	63.30%
2	GS<50	$ 3,149,458	16.41%	$ 3,355,283	12.97%
3	GS>50	$ 4,544,464	23.68%	$ 5,698,280	22.03%
4	Sentinel	$ 34,742	0.18%	$ 51,684	0.20%
5	Street Lights	$ 195,345	1.02%	$ 334,589	1.29%
6	Unmetered Scattered Load	$ 39,551	0.21%	$ 52,856	0.20%
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19					
20					
	Total	$ 19,190,367	100.00%	**$ 25,863,021**	100.00%

Allocated Revenue Requirement does not match Base Revenue Requirement from Sheet 9. Check data.	**Service Revenue Requirement (from Sheet 9)**	**$ 28,779,880.01**

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

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 12,939,404	$ 13,963,979	$ 13,963,979	$ 1,720,529
2	GS<50	$ 3,400,437	$ 3,669,692	$ 3,669,692	$ 344,761
3	GS>50	$ 4,864,549	$ 5,249,737	$ 5,249,737	$ 520,902
4	Sentinel	$ 36,638	$ 39,540	$ 39,540	$ 8,469
5	Street Lights	$ 222,463	$ 240,078	$ 240,078	$ 51,470
6	Unmetered Scattered Load	$ 42,539	$ 45,908	$ 45,908	$ 7,955
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16					
17					
18					
19					
20					
	Total	$ 21,506,030	$ 23,208,934	$ 23,208,934	$ 2,654,087

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

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

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

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

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2018 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	92.62%	95.81%	95.81%	85 - 115
2	GS<50	116.08%	119.65%	119.65%	80 - 120
3	GS>50	111.07%	101.27%	101.27%	80 - 120
4	Sentinel	97.22%	92.89%	92.89%	80 - 120
5	Street Lights	120.00%	87.14%	87.14%	80 - 120
6	Unmetered Scattered Load	112.71%	101.90%	101.90%	80 - 120
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(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

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

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

(D) ***Proposed Revenue-to-Cost Ratios*** (11)

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
			1	2	
1	Residential	95.81%	95.81%	95.81%	85 - 115
2	GS<50	119.65%	119.65%	119.65%	80 - 120
3	GS>50	101.27%	101.27%	101.27%	80 - 120
4	Sentinel	92.89%	92.89%	92.89%	80 - 120
5	Street Lights	87.14%	87.14%	87.14%	80 - 120
6	Unmetered Scattered Load	101.90%	101.90%	101.90%	80 - 120
7					
8					
9					
10					
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(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2021 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2022 and 2023 Price Cap IR models, as necessary. For 2022 and 2023, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2019 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Design and Revenue Reconciliation

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

Stage in Process: *Per Board Decision*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)
1	Residential	kWh	30,340	282,922,375	-	$ 13,963,979	$ 13,963,979	$ -	100.00%	0.00%	
2	GS<50	kWh	3,400	86,539,469	-	$ 3,669,692	$ 910,656	$ 2,759,036	24.82%	75.18%	
3	GS>50	kW	344	232,644,288	575,372	$ 5,249,737	$ 508,859	$ 4,740,878	9.69%	90.31%	$ 67,200
4	Sentinel	kW	317	193,841	566	$ 39,540	$ 16,544	$ 22,996	41.84%	58.16%	
5	Street Lights	kW	8,037	2,459,994	7,200	$ 240,078	$ 161,325	$ 78,753	67.20%	32.80%	
6	Unmetered Scattered Load	kWh	25	878,528	-	$ 45,908	$ 4,101	$ 41,807	8.93%	91.07%	
7			-	-	-						
8			-	-	-						
9			-	-	-						
10			-	-	-						
11			-	-	-						
12			-	-	-						
13			-	-	-						
14			-	-	-						
15			-	-	-						
16			-	-	-						
17			-	-	-						
18			-	-	-						
19			-	-	-						
20			-	-	-						

		Distribution Rates					Revenue Reconciliation		
	Customer Class	Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate		Volumetric Rate No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	$38.35	2	$0.0000	/kWh	4	$ 13,962,468.00	$ -	$ 13,962,468.00
2	GS<50	$ 22.32		$ 0.0319	/kWh		$ 910,656.00	$ 2,760,609.0547	$ 3,671,265.05
3	GS>50	$ 123.27		$ 8.3565	/kW		$ 508,858.56	$ 4,808,095.6161	$ 5,249,754.18
4	Sentinel	$ 4.35		$ 40.6108	/kW		$ 16,547.40	$ 22,995.7657	$ 39,543.17
5	Street Lights	$ 1.67		$ 10.9378	/kW		$ 161,061.48	$ 78,752.8700	$ 239,814.35
6	Unmetered Scattered Load	$ 13.67		$ 0.0476	/kWh		$ 4,101.00	$ 41,817.9451	$ 45,918.95
7							$ -	$ -	$ -
8							$ -	$ -	$ -
9							$ -	$ -	$ -
10							$ -	$ -	$ -
11							$ -	$ -	$ -
12							$ -	$ -	$ -
13							$ -	$ -	$ -
14							$ -	$ -	$ -
15							$ -	$ -	$ -
16							$ -	$ -	$ -
17							$ -	$ -	$ -
18							$ -	$ -	$ -
19							$ -	$ -	$ -
20							$ -	$ -	$ -

Total Transformer Ownership Allowance $ 67,200

Total Distribution Revenues	$23,208,763.70
Base Revenue Requirement	$23,208,933.91
Difference	-$ 170.21
% Difference	-0.001%

Rates recover revenue requirement

Notes:

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Tracking Form

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

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

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

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

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 7,803,354	5.73%	$ 136,089,188	$ 75,430,704	$ 5,657,303	$ 5,425,413	$ 574,141	$ 13,533,701	$ 27,752,199	$ 2,750,265	$ 25,001,934	$ 3,918,555
1	28-Nov-22	Interrogatories	$ 8,706,009	6.40%	$ 136,039,893	$ 74,340,405	$ 5,575,530	$ 5,440,457	$ 684,022	$ 13,533,701	$ 28,779,880	$ 2,867,022	$ 25,912,858	$ 4,878,651

Appendix B - Updated Appendix 2-AB: Capital Expenditure Summary

File Number:	EB-2022-0059
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	August 31, 2022

TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

Appendix 2-AB

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

First year of Forecast Period:

2023

CATEGORY	Historical Period (previous plan[1] & actual)																Forecast Period (planned)				
	2018			2019			2020			2021			2022								
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	YTD Actual	Budget	Var (YTD actual vs. plan)	2023	2024	2025	2026	2027
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000			%	$ '000				
System Access	1,541	1,890	22.6%	2,043	2,475	21.2%	2,552	2,364	-7.4%	2,052	2,154	5.0%	2,035	2,180	1,836	7.1%	2,339	2,672	2,792	2,494	2,357
System Renewal	3,761	3,599	-4.3%	7,357	3,172	-56.9%	3,328	3,397	2.1%	4,565	8,918	95.4%	7,129	3,054	5,394	-57.2%	4,356	4,240	3,442	3,548	2,567
System Service		73	--		-	--		-	--		154	--	-	15,291	15,604	#DIV/0!		127	841	750	5,859
General Plant	86	14	-83.6%	55	188	244.3%	62	124	100.0%	60	593	890.8%	55	118	36	113.4%	150	813	1,033	432	633
TOTAL EXPENDITURE	5,388	5,576	3.5%	9,454	5,835	-38.3%	5,941	5,884	-1.0%	6,676	11,820	77.0%	9,219	20,643	22,869	123.9%	6,845	7,853	8,109	7,224	11,416
Capital Contributions	450	431	-4.2%	458	1,112	142.5%	496	658	32.6%	480	586	22.1%	511	3,860	4,171	655.1%	593	616	642	612	624
Net Capital Expenditures	4,938	5,145	4.2%	8,996	4,723	-47.5%	5,445	5,226	-4.0%	6,197	11,234	81.3%	8,708	16,783	18,698	92.7%	6,252	7,236	7,467	6,612	10,792
System O&M	$ 6,300	$ 6,010	-4.6%	$ 6,306	$ 6,302	-0.1%	$ 6,400	$ 6,434	0.5%	$ 6,496	$ 6,407	-1.4%	$ 6,594	$ 5,053	$ 6,680	-23.4%	$ 7,335	$ 7,644	$ 8,026	$ 8,428	$ 8,849
Settlement OM&A Adjustment																	-$ 550				

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last OEB-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):
3. System O&M contains the following accounts: 5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5060, 5065, 5070, 5075, 5085, 5090, 5095, 5096, 5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5165, 5170, 5172, 5175, 5178, 51

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

Appendix C - Updated Appendix 2-BA: 2023 Fixed Asset Continuity Schedules

File Number:	EB-2022-0059
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	August 31, 2022

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts. If this is the first application where the applicant is rebasing under MIFRS, contact OEB staff for further guidance on the appropriate fixed asset continuity schedules to complete (i.e. applicable years and accounting standard for each schedule).

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues. Amortization of deferred revenue will be removed from the depreciation expense shown on this fixed asset continuity schedule as it should be included as income in Appendix 2-H Other Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

7 This account includes the amount recorded under finance leases for plant leased from others and used by the utility in its utility operations.

8 The applicant must establish the continuity of historical cost for gross assets and accumulated depreciation by asset class by ensuring that the opening balance in the year agrees to the closing balance in the prior year.

Accounting Standard MIFRS
Year 2018

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]			Cost: Closing Balance	RRR DATA	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]			Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1706	Land Rights	$ 602,307					$ 602,307		$ -	$ -				$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339					$ 1,604,339		$ 156,521	$ 39,130				$ 195,651	$ 1,408,688
47	1730	Overhead Conductors & Devices	$ 63,894					$ 63,894		$ 7,987	$ 1,997				$ 9,983	$ 53,911
47	1735	Underground Conduit	$ 870,020					$ 870,020		$ 99,431	$ 24,858				$ 124,289	$ 745,732
47	1740	Underground Conductors & Devices	$ 215,252					$ 215,252		$ 39,137	$ 9,784				$ 48,921	$ 166,331
	1609	Capital Contributions Paid						$ -	$ -						$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)						$ -	$ -						$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)						$ -	$ 189,356						$ -	$ -
N/A	1805	Land	$ 89,160	$ -	-$ 32,744			$ 56,415	$ 56,415						$ -	$ 56,415
CEC	1806	Land Rights	$ 178,951	$ 10,405				$ 189,356							$ -	$ 189,356
47	1808	Buildings	$ 25,027,092	$ 8,455				$ 25,035,547	$ 25,035,547	$ 2,717,413	$ 683,038				$ 3,400,451	$ 21,635,096
13	1810	Leasehold Improvements						$ -	$ -						$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 7,662,606	$ 292,263				$ 7,954,869	$ 7,954,869	$ 1,000,670	$ 286,747				$ 1,287,417	$ 6,667,452
47	1820	Distribution Station Equipment <50 kV	$ 10,510,642	$ 338,454				$ 10,849,096	$ 10,849,096	$ 1,597,765	$ 426,800				$ 2,024,565	$ 8,824,531
47	1825	Storage Battery Equipment	$ 13,722	$ -				$ 13,722	$ 13,722	$ 2,614	$ 653				$ 3,267	$ 10,455
47	1830	Poles, Towers & Fixtures	$ 17,808,103	$ 1,743,944				$ 19,552,048	$ 19,552,048	$ 1,301,617	$ 420,389				$ 1,722,005	$ 17,830,043
47	1835	Overhead Conductors & Devices	$ 12,985,479	$ 953,873				$ 13,939,351	$ 13,939,351	$ 1,073,638	$ 317,104				$ 1,390,742	$ 12,548,610
47	1840	Underground Conduit	$ 3,662,059	$ 405,688				$ 4,067,747	$ 4,067,747	$ 897,887	$ 238,547				$ 1,136,434	$ 2,931,313
47	1845	Underground Conductors & Devices	$ 13,447,279	$ 311,100				$ 13,758,378	$ 13,758,378	$ 2,105,522	$ 551,408				$ 2,656,931	$ 11,101,447
47	1850	Line Transformers	$ 13,256,636	$ 722,098				$ 13,978,734	$ 13,978,734	$ 1,130,181	$ 346,378				$ 1,476,559	$ 12,502,175
47	1855	Services (Overhead & Underground)	$ 6,076,631	$ 577,442				$ 6,654,074	$ 6,654,074	$ 583,072	$ 166,936				$ 750,009	$ 5,904,065
47	1860	Meters	$ 4,838,566	$ 145,913				$ 4,984,479	$ 4,984,479	$ 1,678,254	$ 435,774				$ 2,114,028	$ 2,870,451
47	1860	Meters (Smart Meters)						$ -	$ 4,984,479						$ -	$ -
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)						$ -	$ -						$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)						$ -	$ -						$ -	$ -
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	$ 1,600,673	$ 66,076				$ 1,666,749	$ 1,666,749	$ 952,647	$ 242,873				$ 1,195,521	$ 471,228
47	1985	Miscellaneous Fixed Assets						$ -	$ -						$ -	$ -
47	1990	Other Tangible Property						$ -	$ -						$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739	$ -				-$ 11,161,739	-$ 14,446,706	-$ 1,313,146	-$ 328,286				-$ 1,641,432	-$ 9,520,307
47	2440	Deferred Revenue[5]	-$ 3,087,531	-$ 431,033				-$ 3,518,564	$ -	-$ 151,021	-$ 82,576				-$ 233,597	-$ 3,284,967
	2005	Property Under Finance Lease[7]						$ -	$ -						$ -	$ -
		Sub-Total	**$ 106,264,142**	**$ 5,144,679**	**-$ 32,744**	**$ -**	**$ -**	**$ 111,376,076**	**$ 113,238,339**	**$ 13,880,189**	**$ 3,781,554**	**$ -**	**$ -**	**$ -**	**$ 17,661,743**	**$ 93,714,333**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -							$ -	$ -
		Total PP&E	**$ 106,264,142**	**$ 5,144,679**	**-$ 32,744**	**$ -**	**$ -**	**$ 111,376,076**		**$ 13,880,189**	**$ 3,781,554**	**$ -**	**$ -**	**$ -**	**$ 17,661,743**	**$ 93,714,333**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
		Total									**$ 3,781,554**					

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 82,576
			Net Depreciation	**$ 3,864,131**

Accounting Standard MIFRS
Year 2019

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]			Cost: Closing Balance	RRR DATA	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]			Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1706	Land Rights	$ 602,307					$ 602,307		$ -					$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339					$ 1,604,339		$ 195,651	$ 39,130				$ 234,781	$ 1,369,558
47	1730	Overhead Conductors & Devices	$ 63,894					$ 63,894		$ 9,983	$ 1,997				$ 11,980	$ 51,914
47	1735	Underground Conduit	$ 870,020					$ 870,020		$ 124,289	$ 24,858				$ 149,146	$ 720,874
47	1740	Underground Conductors & Devices	$ 215,252					$ 215,252		$ 48,921	$ 9,784				$ 58,705	$ 156,547
	1609	Capital Contributions Paid	$ -					$ -	$ -	$ -					$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -					$ -	$ -	$ -					$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -					$ -	$ 189,356	$ -					$ -	$ -
N/A	1805	Land	$ 56,415					$ 56,415	$ 56,415	$ -					$ -	$ 56,415
ECE	1806	Land Rights	$ 189,356	$ 14,311				$ 203,667		$ -					$ -	$ 203,667
47	1808	Buildings	$ 25,035,547	$ 177,803				$ 25,213,351	$ 25,035,547	$ 3,400,451	$ 686,763				$ 4,087,214	$ 21,126,136
13	1810	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 7,954,869	$ 233,949				$ 8,188,818	$ 7,954,869	$ 1,287,417	$ 293,325				$ 1,580,742	$ 6,608,076
47	1820	Distribution Station Equipment <50 kV	$ 10,849,096	$ 226,273				$ 11,075,369	$ 10,849,096	$ 2,024,565	$ 433,859				$ 2,458,424	$ 8,616,944
47	1825	Storage Battery Equipment	$ 13,722					$ 13,722	$ 13,722	$ 3,267	$ 653				$ 3,920	$ 9,801
47	1830	Poles, Towers & Fixtures	$ 19,552,048	$ 2,058,945				$ 21,610,992	$ 19,552,048	$ 1,722,005	$ 462,643				$ 2,184,648	$ 19,426,344

47	1835	Overhead Conductors & Devices	$ 13,939,351	$ 646,542				$ 14,585,893	$ 13,939,351	$ 1,390,742	$ 330,441				$ 1,721,182	$ 12,864,711
47	1840	Underground Conduit	$ 4,067,747	$ 494,913				$ 4,562,660	$ 4,067,747	$ 1,136,434	$ 247,553				$ 1,383,987	$ 3,178,674
47	1845	Underground Conductors & Devices	$ 13,758,378	$ 314,478				$ 14,072,856	$ 13,758,378	$ 2,656,931	$ 559,228				$ 3,216,159	$ 10,856,697
47	1850	Line Transformers	$ 13,978,734	$ 898,402				$ 14,877,136	$ 13,978,734	$ 1,476,559	$ 367,055				$ 1,843,614	$ 13,033,522
47	1855	Services (Overhead & Underground)	$ 6,654,074	$ 536,808				$ 7,190,881	$ 6,654,074	$ 750,009	$ 190,040				$ 940,049	$ 6,250,832
47	1860	Meters	$ 4,984,479	$ 76,616				$ 5,061,095	$ 4,984,479	$ 2,114,028	$ 443,191				$ 2,557,219	$ 2,503,876
47	1860	Meters (Smart Meters)	$ -					$ -	$ 4,984,479	$ -					$ -	$ -
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)	$ -					$ -	$ -	$ -					$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -	$ -					$ -	$ -
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	$ 1,666,749	$ 156,497				$ 1,823,246	$ 1,666,749	$ 1,195,521	$ 248,438				$ 1,443,958	$ 379,288
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -	$ -					$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739					-$ 11,161,739	$ -	-$ 1,641,432	-$ 328,286				-$ 1,969,719	-$ 9,192,021
47	2440	Deferred Revenue[5]	-$ 3,518,564	-$ 1,111,843				-$ 4,630,407	$ -	-$ 233,597	-$ 101,862				-$ 335,459	-$ 4,294,948
	2005	Property Under Finance Lease[7]						$ -	$ -	0					$ -	$ -
		Sub-Total	**$ 111,376,076**	**$ 4,723,694**	**$ -**	**$ -**	**$ -**	**$ 116,099,770**	**$ 127,685,045**	**$ 17,661,743**	**$ 3,908,810**	**$ -**	**$ -**	**$ -**	**$ 21,570,553**	**$ 94,529,217**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*						$ -							$ -	$ -
		Total PP&E	**$ 111,376,076**	**$ 4,723,694**	**$ -**	**$ -**	**$ -**	**$ 116,099,770**		**$ 17,661,743**	**$ 3,908,810**	**$ -**	**$ -**	**$ -**	**$ 21,570,553**	**$ 94,529,217**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
		Total									**$ 3,908,810**					

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 101,862
			Net Depreciation	**$ 4,010,672**

Accounting Standard MIFRS
Year **2020**

CCA Class[2]	OEB Account[3]	Description[3]	Cost: Opening Balance[8]	Additions[4]	Disposals[6]			Closing Balance	RRR DATA	Accumulated Depreciation: Opening Balance[8]	Additions	Disposals[6]			Closing Balance	Net Book Value
N/A	1706	Land Rights	$ 602,307					$ 602,307		$ -					$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339					$ 1,604,339		$ 234,781	$ 39,130				$ 273,912	$ 1,330,428
47	1730	Overhead Conductors & Devices	$ 63,894					$ 63,894		$ 11,980	$ 1,997				$ 13,977	$ 49,917
47	1735	Underground Conduit	$ 870,020					$ 870,020		$ 149,146	$ 24,858				$ 174,004	$ 696,016
47	1740	Underground Conductors & Devices	$ 215,252					$ 215,252		$ 58,705	$ 9,784				$ 68,489	$ 146,763
	1609	Capital Contributions Paid	$ -					$ -	$ -	$ -					$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -					$ -	$ -	$ -					$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -					$ -	$ 189,356	$ -					$ -	$ -
N/A	1805	Land	$ 56,415					$ 56,415	$ 56,415	$ -					$ -	$ 56,415
CEC	1806	Land Rights	$ 203,667	$ 14,268				$ 217,935		$ -					$ -	$ 217,935
47	1808	Buildings	$ 25,213,351	$ 125,719				$ 25,339,070	$ 25,035,547	$ 4,087,214	$ 692,833				$ 4,780,048	$ 20,559,022
13	1810	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,188,818	$ 184,850				$ 8,373,668	$ 7,954,869	$ 1,580,742	$ 298,560				$ 1,879,302	$ 6,494,366
47	1820	Distribution Station Equipment <50 kV	$ 11,075,369	$ 531,294				$ 11,606,662	$ 10,849,096	$ 2,458,424	$ 443,329				$ 2,901,753	$ 8,704,909
47	1825	Storage Battery Equipment	$ 13,722					$ 13,722	$ 13,722	$ 3,920	$ 653				$ 4,574	$ 9,148
47	1830	Poles, Towers & Fixtures	$ 21,610,992	$ 1,797,499				$ 23,408,492	$ 19,552,048	$ 2,184,648	$ 505,492				$ 2,690,141	$ 20,718,351
47	1835	Overhead Conductors & Devices	$ 14,585,893	$ 783,153				$ 15,369,046	$ 13,939,351	$ 1,721,182	$ 342,355				$ 2,063,537	$ 13,305,509
47	1840	Underground Conduit	$ 4,562,660	$ 62,255				$ 4,624,916	$ 4,067,747	$ 1,383,987	$ 253,124				$ 1,637,111	$ 2,987,805
47	1845	Underground Conductors & Devices	$ 14,072,856	$ 554,440				$ 14,627,297	$ 13,758,378	$ 3,216,159	$ 570,090				$ 3,786,249	$ 10,841,048
47	1850	Line Transformers	$ 14,877,136	$ 953,608				$ 15,830,744	$ 13,978,734	$ 1,843,614	$ 388,011				$ 2,231,625	$ 13,599,120
47	1855	Services (Overhead & Underground)	$ 7,190,881	$ 392,402				$ 7,583,283	$ 6,654,074	$ 940,049	$ 197,068				$ 1,137,117	$ 6,446,167
47	1860	Meters	$ 5,061,095	$ 476,303				$ 5,537,398	$ 4,984,479	$ 2,557,219	$ 461,622				$ 3,018,841	$ 2,518,557
47	1860	Meters (Smart Meters)	$ -					$ -	$ 4,984,479	$ -					$ -	$ -
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)	$ -					$ -	$ -	$ -					$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -	$ -					$ -	$ -
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	$ 1,823,246	$ 9,935				$ 1,833,182	$ 1,666,749	$ 1,443,958	$ 252,599				$ 1,696,557	$ 136,625
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -	$ -					$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739					-$ 11,161,739	$ -	-$ 1,969,719	-$ 328,286				-$ 2,298,005	-$ 8,863,734
47	2440	Deferred Revenue[5]	-$ 4,630,407	-$ 658,166				-$ 5,288,573	$ -	-$ 335,459	-$ 123,987				-$ 459,446	-$ 4,829,126
	2005	Property Under Finance Lease[7]	0					$ -	$ -	0					$ -	$ -
		Sub-Total	**$ 116,099,770**	**$ 5,227,561**	**$ -**	**$ -**	**$ -**	**$ 121,327,331**	**$ 127,685,045**	**$ 21,570,553**	**$ 4,029,231**	**$ -**	**$ -**	**$ -**	**$ 25,599,783**	**$ 95,727,548**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*						$ -							$ -	$ -
		Total PP&E	**$ 116,099,770**	**$ 5,227,561**	**$ -**	**$ -**	**$ -**	**$ 121,327,331**		**$ 21,570,553**	**$ 4,029,231**	**$ -**	**$ -**	**$ -**	**$ 25,599,783**	**$ 95,727,548**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
		Total									**$ 4,029,231**					

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 123,987
			Net Depreciation	**$ 4,153,218**

Accounting Standard MIFRS
Year **2021**

CCA Class[2]	OEB Account[3]	Description[3]	Cost: Opening Balance[8]	Additions[4]	Disposals[6]			Closing Balance	RRR DATA	Accumulated Depreciation: Opening Balance[8]	Additions	Disposals[6]			Closing Balance	Net Book Value
N/A	1706	Land Rights	$ 602,307					$ 602,307		$ -					$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339					$ 1,604,339		$ 273,912	$ 39,130				$ 313,042	$ 1,291,298
47	1730	Overhead Conductors & Devices	$ 63,894					$ 63,894		$ 13,977	$ 1,997				$ 15,974	$ 47,921
47	1735	Underground Conduit	$ 870,020					$ 870,020		$ 174,004	$ 24,858				$ 198,862	$ 671,159
47	1740	Underground Conductors & Devices	$ 215,252					$ 215,252		$ 68,489	$ 9,784				$ 78,274	$ 136,979
	1609	Capital Contributions Paid	$ -					$ -	$ -	$ -					$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -					$ -	$ -	$ -					$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -					$ -	$ 189,356	$ -					$ -	$ -
N/A	1805	Land	$ 56,415					$ 56,415	$ 56,415	$ -					$ -	$ 56,415
CEC	1806	Land Rights	$ 217,935	$ 157,463				$ 375,398		$ -					$ -	$ 375,398

47	1808	Buildings	$ 25,339,070	$ 584,705				$ 25,923,775	$ 25,035,547	$ 4,780,048	$ 706,421				$ 5,486,469	$ 20,437,306
13	1810	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,373,668	$ 70,828				$ 8,444,495	$ 7,954,869	$ 1,879,302	$ 301,756				$ 2,181,057	$ 6,263,438
47	1820	Distribution Station Equipment <50 kV	$ 11,606,662	$ 575,333		$ 6,020,120		$ 18,202,115	$ 10,849,096	$ 2,901,753	$ 457,162		$ 225,754		$ 3,584,669	$ 14,617,446
47	1825	Storage Battery Equipment	$ 13,722					$ 13,722	$ 13,722	$ 4,574	$ 653				$ 5,227	$ 8,494
47	1830	Poles, Towers & Fixtures	$ 23,408,492	$ 1,574,663				$ 24,983,155	$ 19,552,048	$ 2,690,141	$ 542,961				$ 3,233,102	$ 21,750,053
47	1835	Overhead Conductors & Devices	$ 15,369,046	$ 507,099				$ 15,876,144	$ 13,939,351	$ 2,063,537	$ 353,107				$ 2,416,644	$ 13,459,500
47	1840	Underground Conduit	$ 4,624,916	$ 183,281				$ 4,808,197	$ 4,067,747	$ 1,637,111	$ 255,580				$ 1,892,691	$ 2,915,506
47	1845	Underground Conductors & Devices	$ 14,627,297	$ 563,813				$ 15,191,109	$ 13,758,378	$ 3,786,249	$ 584,068				$ 4,370,317	$ 10,820,793
47	1850	Line Transformers	$ 15,830,744	$ 772,929				$ 16,603,673	$ 13,978,734	$ 2,231,625	$ 406,873				$ 2,638,498	$ 13,965,175
47	1855	Services (Overhead & Underground)	$ 7,583,283	$ 592,995				$ 8,176,278	$ 6,654,074	$ 1,137,117	$ 209,385				$ 1,346,502	$ 6,829,776
47	1860	Meters	$ 5,537,398	$ 216,522				$ 5,753,920	$ 4,984,479	$ 3,018,841	$ 484,716				$ 3,503,557	$ 2,250,364
47	1860	Meters (Smart Meters)	$ -					$ -	$ 4,984,479	$ -					$ -	$ -
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)	$ -					$ -	$ -	$ -					$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -	$ -					$ -	$ -
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	$ 1,833,182	$ -				$ 1,833,182	$ 1,666,749	$ 1,696,557	-$ 207,938				$ 1,488,619	$ 344,563
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -	$ -					$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739					-$ 11,161,739	$ -	-$ 2,298,005	-$ 328,286				-$ 2,626,292	-$ 8,535,448
47	2440	Deferred Revenue[5]	-$ 5,288,573	-$ 641,214				-$ 5,929,786	$ -	-$ 459,446	-$ 140,229				-$ 599,676	-$ 5,330,111
	2005	Property Under Finance Lease[7]	0					$ -	$ -	0					$ -	$ -
		Sub-Total	**$ 121,327,331**	**$ 5,158,416**	**$ -**	**$ 6,020,120**	**$ -**	**$ 132,505,867**	**$ 127,685,045**	**$ 25,599,783**	**$ 3,701,996**	**$ -**	**$ 225,754**	**$ -**	**$ 29,527,534**	**$ 102,978,333**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -							$ -	$ -
		Total PP&E	**$ 121,327,331**	**$ 5,158,416**	**$ -**	**$ 6,020,120**	**$ -**	**$ 132,505,867**		**$ 25,599,783**	**$ 3,701,996**	**$ -**	**$ 225,754**	**$ -**	**$ 29,527,534**	**$ 102,978,333**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
		Total									**$ 3,701,996**					

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 140,229
			Net Depreciation	**$ 3,842,226**

Accounting Standard MIFRS
Year **2022**

			Cost							Accumulated Depreciation						
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**ICM Sub 16**	**ICM SSG**	**Closing Balance**	**RRR DATA**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**ICM Sub 16**	**ICM SSG**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307					$ 602,307		$ -					$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339					$ 1,604,339		$ 313,042	$ 39,130				$ 352,172	$ 1,252,167
47	1730	Overhead Conductors & Devices	$ 63,894					$ 63,894		$ 15,974	$ 1,997				$ 17,970	$ 45,924
47	1735	Underground Conduit	$ 870,020					$ 870,020		$ 198,862	$ 24,858				$ 223,720	$ 646,301
47	1740	Underground Conductors & Devices	$ 215,252					$ 215,252		$ 78,274	$ 9,784				$ 88,058	$ 127,194
	1609	Capital Contributions Paid	$ -					$ -	$ -	$ -					$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -					$ -	$ -	$ -					$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -					$ -	$ 189,356	$ -					$ -	$ -
N/A	1805	Land	$ 56,415					$ 56,415	$ 56,415	$ -					$ -	$ 56,415
CEC	1806	Land Rights	$ 375,398					$ 375,398		$ -					$ -	$ 375,398
47	1808	Buildings	$ 25,923,775	$ 35,828				$ 25,959,603	$ 25,035,547	$ 5,486,469	$ 719,297				$ 6,205,766	$ 19,753,837
13	1810	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,444,495	$ 64,636				$ 8,509,131	$ 7,954,869	$ 2,181,057	$ 303,449				$ 2,484,506	$ 6,024,625
47	1820	Distribution Station Equipment <50 kV	$ 18,202,115	$ 2,157,721				$ 20,359,836	$ 10,849,096	$ 3,584,669	$ 491,325		$ 150,503		$ 4,226,497	$ 16,133,339
47	1825	Storage Battery Equipment	$ 13,722	$ -				$ 13,722	$ 13,722	$ 5,227	$ 653				$ 5,881	$ 7,841
47	1830	Poles, Towers & Fixtures	$ 24,983,155	$ 2,467,354				$ 27,450,508	$ 19,552,048	$ 3,233,102	$ 587,872				$ 3,820,974	$ 23,629,534
47	1835	Overhead Conductors & Devices	$ 15,876,144	$ 551,951				$ 16,428,095	$ 13,939,351	$ 2,416,644	$ 361,932				$ 2,778,576	$ 13,649,519
47	1840	Underground Conduit	$ 4,808,197	$ 635,945				$ 5,444,141	$ 4,067,747	$ 1,892,691	$ 263,772				$ 2,156,463	$ 3,287,678
47	1845	Underground Conductors & Devices	$ 15,191,109	$ 113,309				$ 15,304,418	$ 13,758,378	$ 4,370,317	$ 592,532				$ 4,962,848	$ 10,341,570
47	1850	Line Transformers	$ 16,603,673	$ 561,961				$ 17,165,634	$ 13,978,734	$ 2,638,498	$ 423,863				$ 3,062,361	$ 14,103,273
47	1855	Services (Overhead & Underground)	$ 8,176,278	$ 503,053				$ 8,679,331	$ 6,654,074	$ 1,346,502	$ 223,086				$ 1,569,587	$ 7,109,743
47	1860	Meters	$ 5,753,920	$ 173,168				$ 5,927,089	$ 4,984,479	$ 3,503,557	$ 497,706				$ 4,001,263	$ 1,925,826
47	1860	Meters (Smart Meters)	$ -					$ -	$ 4,984,479	$ -					$ -	$ -
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)	$ -					$ -	$ -	$ -					$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -	$ -					$ -	$ -
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	$ 1,833,182					$ 1,833,182	$ 1,666,749	$ 1,488,619	$ 22,579				$ 1,511,197	$ 321,984
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -	$ -					$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739					-$ 11,161,739	$ -	-$ 2,626,292	-$ 328,286				-$ 2,954,578	-$ 8,207,161
47	2440	Deferred Revenue[5]	-$ 5,929,786	-$ 492,800				-$ 6,422,586	$ -	-$ 599,676	-$ 154,405				-$ 754,080	-$ 5,668,506
	2005	Property Under Finance Lease[7]	$ -					$ -	$ -	$ -					$ -	$ -
		Sub-Total	**$ 132,505,867**	**$ 6,772,124**	**$ -**	**$ -**	**$ -**	**$ 139,277,991**	**$ 127,685,045**	**$ 29,527,534**	**$ 4,081,144**	**$ -**	**$ 150,503**	**$ -**	**$ 33,759,181**	**$ 105,518,810**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -							$ -	$ -
		Total PP&E	**$ 132,505,867**	**$ 6,772,124**	**$ -**	**$ -**	**$ -**	**$ 139,277,991**		**$ 29,527,534**	**$ 4,081,144**	**$ -**	**$ 150,503**	**$ -**	**$ 33,759,181**	**$ 105,518,810**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
		Total									**$ 4,231,647**					

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 154,405
			Net Depreciation	**$ 4,386,052**

Accounting Standard MIFRS
Year **2023**

			Cost							Accumulated Depreciation						
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**ICM Sub 16**	**ICM SSG**	**Closing Balance**	**RRR DATA**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**ICM Sub 16**	**ICM SSG**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307					$ 602,307		$ -					$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339					$ 1,604,339		$ 352,172	$ 39,130				$ 391,302	$ 1,213,037
47	1730	Overhead Conductors & Devices	$ 63,894					$ 63,894		$ 17,970	$ 1,997				$ 19,967	$ 43,927
47	1735	Underground Conduit	$ 870,020					$ 870,020		$ 223,720	$ 24,858				$ 248,577	$ 621,443
47	1740	Underground Conductors & Devices	$ 215,252					$ 215,252		$ 88,058	$ 9,784				$ 97,842	$ 117,410

	1609	Capital Contributions Paid	$ -					$ -	$ -	$ -					$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ 80,000				$ 80,000	$ -	$ -	$ 8,000				$ 8,000	$ 72,000
CEC	1612	Land Rights (Formally known as Account 1906)	$ -					$ -	$ 189,356	$ -					$ -	$ -
N/A	1805	Land	$ 56,415					$ 56,415	$ 56,415	$ -					$ -	$ 56,415
CEC	1806	Land Rights	$ 375,398					$ 375,398		$ -					$ -	$ 375,398
47	1808	Buildings	$ 25,959,603	$ 70,346				$ 26,029,949	$ 25,035,547	$ 6,205,766	$ 721,421				$ 6,927,187	$ 19,102,762
13	1810	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,509,131	$ 85,350				$ 8,594,481	$ 7,954,869	$ 2,484,506	$ 305,324				$ 2,789,830	$ 5,804,651
47	1820	Distribution Station Equipment <50 kV	$ 20,359,836	$ 1,469,155				$ 21,828,991	$ 10,849,096	$ 4,226,497	$ 536,661				$ 4,763,158	$ 17,065,833
47	1825	Storage Battery Equipment	$ 13,722	$ -				$ 13,722	$ 13,722	$ 5,881	$ 653				$ 6,534	$ 7,187
47	1830	Poles, Towers & Fixtures	$ 27,450,508	$ 2,297,400				$ 29,747,908	$ 19,552,048	$ 3,820,974	$ 640,814				$ 4,461,788	$ 25,286,120
47	1835	Overhead Conductors & Devices	$ 16,428,095	$ 576,570				$ 17,004,666	$ 13,939,351	$ 2,778,576	$ 371,297				$ 3,149,874	$ 13,854,792
47	1840	Underground Conduit	$ 5,444,141	$ 691,867				$ 6,136,009	$ 4,067,747	$ 2,156,463	$ 277,050				$ 2,433,513	$ 3,702,496
47	1845	Underground Conductors & Devices	$ 15,304,418	$ 61,153				$ 15,365,571	$ 13,758,378	$ 4,962,848	$ 594,713				$ 5,557,561	$ 9,808,010
47	1850	Line Transformers	$ 17,165,634	$ 788,802				$ 17,954,436	$ 13,978,734	$ 3,062,361	$ 440,748				$ 3,503,109	$ 14,451,328
47	1855	Services (Overhead & Underground)	$ 8,679,331	$ 517,876				$ 9,197,207	$ 6,654,074	$ 1,569,587	$ 235,847				$ 1,805,434	$ 7,391,772
47	1860	Meters	$ 5,927,089	$ 206,980				$ 6,134,068	$ 4,984,479	$ 4,001,263	$ 510,377				$ 4,511,640	$ 1,622,429
47	1860	Meters (Smart Meters)	$ -					$ -	$ 4,984,479	$ -					$ -	$ -
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)	$ -					$ -	$ -	$ -					$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -	$ -					$ -	$ -
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	$ 1,833,182					$ 1,833,182	$ 1,666,749	$ 1,511,197	$ 22,579				$ 1,533,776	$ 299,406
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -	$ -					$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739					-$ 11,161,739	$ -	-$ 2,954,578	-$ 328,286				-$ 3,282,864	-$ 7,878,875
47	2440	Deferred Revenue[5]	-$ 6,422,586	-$ 592,500				-$ 7,015,086	$ -	-$ 754,080	-$ 167,971				-$ 922,051	-$ 6,093,035
	2005	Property Under Finance Lease[7]	0					$ -	$ -	0					$ -	$ -
		Sub-Total	**$ 139,277,991**	**$ 6,253,000**	**$ -**	**$ -**	**$ -**	**$ 145,530,991**	**$ 127,685,045**	**$ 33,759,181**	**$ 4,244,995**	**$ -**	**$ -**	**$ -**	**$ 38,004,177**	**$ 107,526,814**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -							$ -	$ -
		Total PP&E	**$ 139,277,991**	**$ 6,253,000**	**$ -**	**$ -**	**$ -**	**$ 145,530,991**		**$ 33,759,181**	**$ 4,244,995**	**$ -**	**$ -**	**$ -**	**$ 38,004,177**	**$ 107,526,814**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
		Total									**$ 4,244,995**					

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 167,971
			Net Depreciation	**$ 4,412,966**

			Cost							Accumulated Depreciation						
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**			**Closing Balance**	**RRR DATA**	**Opening Balance [8]**	**Additions**	**Disposals [6]**			**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 602,307					$ 602,307	$ -	$ -					$ -	$ 602,307
12	1611	Computer Software (Formally known as Account 1925)	$ 1,604,339					$ 1,604,339	$ -	$ 391,302					$ 391,302	$ 1,995,642
CEC	1612	Land Rights (Formally known as Account 1906)	$ 63,894					$ 63,894	$ -	$ 19,967					$ 19,967	$ 83,861
N/A	1805	Land	$ 870,020					$ 870,020	$ -	$ 248,577					$ 248,577	$ 1,118,598
47	1808	Buildings	$ 215,252					$ 215,252	$ -	$ 97,842					$ 97,842	$ 313,094
13	1810	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 80,000					$ 80,000	$ -	$ 8,000					$ 8,000	$ 88,000
47	1820	Distribution Station Equipment <50 kV	$ -					$ -	$ -	$ -					$ -	$ -
47	1825	Storage Battery Equipment	$ 56,415					$ 56,415	$ -	$ -					$ -	$ 56,415
47	1830	Poles, Towers & Fixtures	$ 26,029,949					$ 26,029,949	$ -	$ 6,927,187					$ 6,927,187	$ 32,957,136
47	1835	Overhead Conductors & Devices	$ -					$ -	$ -	$ -					$ -	$ -
47	1840	Underground Conduit	$ 8,594,481					$ 8,594,481	$ -	$ 2,789,830					$ 2,789,830	$ 11,384,311
47	1845	Underground Conductors & Devices	$ 21,828,991					$ 21,828,991	$ -	$ 4,763,158					$ 4,763,158	$ 26,592,149
47	1850	Line Transformers	$ 13,722					$ 13,722	$ -	$ 6,534					$ 6,534	$ 20,256
47	1855	Services (Overhead & Underground)	$ 29,747,908					$ 29,747,908	$ -	$ 4,461,788					$ 4,461,788	$ 34,209,696
47	1860	Meters	$ 17,004,666					$ 17,004,666	$ -	$ 3,149,874					$ 3,149,874	$ 20,154,539
47	1860	Meters (Smart Meters)	$ 6,136,009					$ 6,136,009	$ -	$ 2,433,513					$ 2,433,513	$ 8,569,522
N/A	1905	Land	$ 15,365,571					$ 15,365,571	$ -	$ 5,557,561					$ 5,557,561	$ 20,923,132
47	1908	Buildings & Fixtures	$ 17,954,436					$ 17,954,436	$ -	$ 3,503,109					$ 3,503,109	$ 21,457,545
13	1910	Leasehold Improvements	$ 9,197,207					$ 9,197,207	$ -	$ 1,805,434					$ 1,805,434	$ 11,002,641
8	1915	Office Furniture & Equipment (10 years)	$ 6,134,068					$ 6,134,068	$ -	$ 4,511,640					$ 4,511,640	$ 10,645,708
8	1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -	$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ -					$ -	$ -	$ -					$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -	$ -					$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -	$ -					$ -	$ -
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	$ -					$ -	$ -	$ -					$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -	$ -					$ -	$ -
47	1995	Contributions & Grants	$ -					$ -	$ -	$ -					$ -	$ -
47	2440	Deferred Revenue[5]	$ -					$ -	$ -	$ -					$ -	$ -
	2005	Property Under Finance Lease[7]	$ 1,833,182					$ 1,833,182	$ -	$ 1,533,776					$ 1,533,776	$ 3,366,958
		Sub-Total	**$ 163,332,418**	**$ -**	**$ -**			**$ 163,332,418**	**$ -**	**$ 42,209,093**	**$ -**	**$ -**			**$ 42,209,093**	**$ 205,541,510**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -							$ -	$ -
		Total PP&E	**$ 163,332,418**	**$ -**	**$ -**			**$ 163,332,418**		**$ 42,209,093**	**$ -**	**$ -**			**$ 42,209,093**	**$ 205,541,510**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
		Total									**$ -**					

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**$ -**

Accounting Standard CGAAP
Year **2025**

			Cost							Accumulated Depreciation						
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**			**Closing Balance**	**RRR DATA**	**Opening Balance [8]**	**Additions**	**Disposals [6]**			**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 602,307					$ 602,307	$ -	$ -					$ -	$ 602,307
12	1611	Computer Software (Formally known as Account 1925)	$ 1,604,339					$ 1,604,339	$ -	$ 391,302					$ 391,302	$ 1,995,642
CEC	1612	Land Rights (Formally known as Account 1906)	$ 63,894					$ 63,894	$ -	$ 19,967					$ 19,967	$ 83,861
N/A	1805	Land	$ 870,020					$ 870,020	$ -	$ 248,577					$ 248,577	$ 1,118,598
47	1808	Buildings	$ 215,252					$ 215,252	$ -	$ 97,842					$ 97,842	$ 313,094
13	1810	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 80,000					$ 80,000	$ -	$ 8,000					$ 8,000	$ 88,000
47	1820	Distribution Station Equipment <50 kV	$ -					$ -	$ -	$ -					$ -	$ -
47	1825	Storage Battery Equipment	$ 56,415					$ 56,415	$ -	$ -					$ -	$ 56,415

47	1830	Poles, Towers & Fixtures	$ 26,029,949					$ 26,029,949	$ -	$ 6,927,187					$ 6,927,187	$ 32,957,136
47	1835	Overhead Conductors & Devices	$ -					$ -	$ -	$ -					$ -	$ -
47	1840	Underground Conduit	$ 8,594,481					$ 8,594,481	$ -	$ 2,789,830					$ 2,789,830	$ 11,384,311
47	1845	Underground Conductors & Devices	$ 21,828,991					$ 21,828,991	$ -	$ 4,763,158					$ 4,763,158	$ 26,592,149
47	1850	Line Transformers	$ 13,722					$ 13,722	$ -	$ 6,534					$ 6,534	$ 20,256
47	1855	Services (Overhead & Underground)	$ 29,747,908					$ 29,747,908	$ -	$ 4,461,788					$ 4,461,788	$ 34,209,696
47	1860	Meters	$ 17,004,666					$ 17,004,666	$ -	$ 3,149,874					$ 3,149,874	$ 20,154,539
47	1860	Meters (Smart Meters)	$ 6,136,009					$ 6,136,009	$ -	$ 2,433,513					$ 2,433,513	$ 8,569,522
N/A	1905	Land	$ 15,365,571					$ 15,365,571	$ -	$ 5,557,561					$ 5,557,561	$ 20,923,132
47	1908	Buildings & Fixtures	$ 17,954,436					$ 17,954,436	$ -	$ 3,503,109					$ 3,503,109	$ 21,457,545
13	1910	Leasehold Improvements	$ 9,197,207					$ 9,197,207	$ -	$ 1,805,434					$ 1,805,434	$ 11,002,641
8	1915	Office Furniture & Equipment (10 years)	$ 6,134,068					$ 6,134,068	$ -	$ 4,511,640					$ 4,511,640	$ 10,645,708
8	1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -	$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ -					$ -	$ -	$ -					$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -	$ -					$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -	$ -					$ -	$ -
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	$ -					$ -	$ -	$ -					$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -	$ -					$ -	$ -
47	1995	Contributions & Grants	$ -					$ -	$ -	$ -					$ -	$ -
47	2440	Deferred Revenue[5]	$ -					$ -	$ -	$ -					$ -	$ -
	2005	Property Under Finance Lease[7]	$ 1,833,182					$ 1,833,182	$ -	$ 1,533,776					$ 1,533,776	$ 3,366,958
		Sub-Total	**$ 163,332,418**	**$ -**	**$ -**			**$ 163,332,418**	**$ -**	**$ 42,209,093**	**$ -**	**$ -**			**$ 42,209,093**	**$ 205,541,510**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -							$ -	$ -
		Total PP&E	**$ 163,332,418**	**$ -**	**$ -**			**$ 163,332,418**		**$ 42,209,093**	**$ -**	**$ -**			**$ 42,209,093**	**$ 205,541,510**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
		Total									**$ -**					

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**$ -**

Accounting Standard CGAAP
Year **2026**

			Cost							Accumulated Depreciation						
CCA Class[2]	**OEB Account[3]**	**Description[3]**	**Opening Balance[8]**	**Additions[4]**	**Disposals[6]**			**Closing Balance**	**RRR DATA**	**Opening Balance[8]**	**Additions**	**Disposals[6]**			**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 602,307					$ 602,307	$ -	$ -					$ -	$ 602,307
12	1611	Computer Software (Formally known as Account 1925)	$ 1,604,339					$ 1,604,339	$ -	$ 391,302					$ 391,302	$ 1,995,642
CEC	1612	Land Rights (Formally known as Account 1906)	$ 63,894					$ 63,894	$ -	$ 19,967					$ 19,967	$ 83,861
N/A	1805	Land	$ 870,020					$ 870,020	$ -	$ 248,577					$ 248,577	$ 1,118,598
47	1808	Buildings	$ 215,252					$ 215,252	$ -	$ 97,842					$ 97,842	$ 313,094
13	1810	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 80,000					$ 80,000	$ -	$ 8,000					$ 8,000	$ 88,000
47	1820	Distribution Station Equipment <50 kV	$ -					$ -	$ -	$ -					$ -	$ -
47	1825	Storage Battery Equipment	$ 56,415					$ 56,415	$ -	$ -					$ -	$ 56,415
47	1830	Poles, Towers & Fixtures	$ 26,029,949					$ 26,029,949	$ -	$ 6,927,187					$ 6,927,187	$ 32,957,136
47	1835	Overhead Conductors & Devices	$ -					$ -	$ -	$ -					$ -	$ -
47	1840	Underground Conduit	$ 8,594,481					$ 8,594,481	$ -	$ 2,789,830					$ 2,789,830	$ 11,384,311
47	1845	Underground Conductors & Devices	$ 21,828,991					$ 21,828,991	$ -	$ 4,763,158					$ 4,763,158	$ 26,592,149
47	1850	Line Transformers	$ 13,722					$ 13,722	$ -	$ 6,534					$ 6,534	$ 20,256
47	1855	Services (Overhead & Underground)	$ 29,747,908					$ 29,747,908	$ -	$ 4,461,788					$ 4,461,788	$ 34,209,696
47	1860	Meters	$ 17,004,666					$ 17,004,666	$ -	$ 3,149,874					$ 3,149,874	$ 20,154,539
47	1860	Meters (Smart Meters)	$ 6,136,009					$ 6,136,009	$ -	$ 2,433,513					$ 2,433,513	$ 8,569,522
N/A	1905	Land	$ 15,365,571					$ 15,365,571	$ -	$ 5,557,561					$ 5,557,561	$ 20,923,132
47	1908	Buildings & Fixtures	$ 17,954,436					$ 17,954,436	$ -	$ 3,503,109					$ 3,503,109	$ 21,457,545
13	1910	Leasehold Improvements	$ 9,197,207					$ 9,197,207	$ -	$ 1,805,434					$ 1,805,434	$ 11,002,641
8	1915	Office Furniture & Equipment (10 years)	$ 6,134,068					$ 6,134,068	$ -	$ 4,511,640					$ 4,511,640	$ 10,645,708
8	1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -	$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ -					$ -	$ -	$ -					$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -	$ -					$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -	$ -					$ -	$ -
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	$ -					$ -	$ -	$ -					$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -	$ -					$ -	$ -
47	1995	Contributions & Grants	$ -					$ -	$ -	$ -					$ -	$ -
47	2440	Deferred Revenue[5]	$ -					$ -	$ -	$ -					$ -	$ -
	2005	Property Under Finance Lease[7]	$ 1,833,182					$ 1,833,182	$ -	$ 1,533,776					$ 1,533,776	$ 3,366,958
		Sub-Total	**$ 163,332,418**	**$ -**	**$ -**			**$ 163,332,418**	**$ -**	**$ 42,209,093**	**$ -**	**$ -**			**$ 42,209,093**	**$ 205,541,510**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -							$ -	$ -
		Total PP&E	**$ 163,332,418**	**$ -**	**$ -**			**$ 163,332,418**		**$ 42,209,093**	**$ -**	**$ -**			**$ 42,209,093**	**$ 205,541,510**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
		Total									**$ -**					

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**$ -**

Accounting Standard CGAAP
Year **2027**

			Cost							Accumulated Depreciation						
CCA Class[2]	**OEB Account[3]**	**Description[3]**	**Opening Balance[8]**	**Additions[4]**	**Disposals[6]**			**Closing Balance**	**RRR DATA**	**Opening Balance[8]**	**Additions**	**Disposals[6]**			**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 602,307					$ 602,307	$ -	$ -					$ -	$ 602,307
12	1611	Computer Software (Formally known as Account 1925)	$ 1,604,339					$ 1,604,339	$ -	$ 391,302					$ 391,302	$ 1,995,642
CEC	1612	Land Rights (Formally known as Account 1906)	$ 63,894					$ 63,894	$ -	$ 19,967					$ 19,967	$ 83,861
N/A	1805	Land	$ 870,020					$ 870,020	$ -	$ 248,577					$ 248,577	$ 1,118,598
47	1808	Buildings	$ 215,252					$ 215,252	$ -	$ 97,842					$ 97,842	$ 313,094
13	1810	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 80,000					$ 80,000	$ -	$ 8,000					$ 8,000	$ 88,000
47	1820	Distribution Station Equipment <50 kV	$ -					$ -	$ -	$ -					$ -	$ -
47	1825	Storage Battery Equipment	$ 56,415					$ 56,415	$ -	$ -					$ -	$ 56,415
47	1830	Poles, Towers & Fixtures	$ 26,029,949					$ 26,029,949	$ -	$ 6,927,187					$ 6,927,187	$ 32,957,136
47	1835	Overhead Conductors & Devices	$ -					$ -	$ -	$ -					$ -	$ -
47	1840	Underground Conduit	$ 8,594,481					$ 8,594,481	$ -	$ 2,789,830					$ 2,789,830	$ 11,384,311
47	1845	Underground Conductors & Devices	$ 21,828,991					$ 21,828,991	$ -	$ 4,763,158					$ 4,763,158	$ 26,592,149
47	1850	Line Transformers	$ 13,722					$ 13,722	$ -	$ 6,534					$ 6,534	$ 20,256
47	1855	Services (Overhead & Underground)	$ 29,747,908					$ 29,747,908	$ -	$ 4,461,788					$ 4,461,788	$ 34,209,696
47	1860	Meters	$ 17,004,666					$ 17,004,666	$ -	$ 3,149,874					$ 3,149,874	$ 20,154,539

47	1860	Meters (Smart Meters)	$ 6,136,009					$ 6,136,009	$ -	$ 2,433,513					$ 2,433,513	$ 8,569,522
N/A	1905	Land	$ 15,365,571					$ 15,365,571	$ -	$ 5,557,561					$ 5,557,561	$ 20,923,132
47	1908	Buildings & Fixtures	$ 17,954,436					$ 17,954,436	$ -	$ 3,503,109					$ 3,503,109	$ 21,457,545
13	1910	Leasehold Improvements	$ 9,197,207					$ 9,197,207	$ -	$ 1,805,434					$ 1,805,434	$ 11,002,641
8	1915	Office Furniture & Equipment (10 years)	$ 6,134,068					$ 6,134,068	$ -	$ 4,511,640					$ 4,511,640	$ 10,645,708
8	1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -	$ -					$ -	$ -
10	1920	Computer Equipment - Hardware	$ -					$ -	$ -	$ -					$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -	$ -					$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -	$ -					$ -	$ -
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	$ -					$ -	$ -	$ -					$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -	$ -					$ -	$ -
47	1995	Contributions & Grants	$ -					$ -	$ -	$ -					$ -	$ -
47	2440	Deferred Revenue[5]	$ -					$ -	$ -	$ -					$ -	$ -
	2005	Property Under Finance Lease[7]	$ 1,833,182					$ 1,833,182	$ -	$ 1,533,776					$ 1,533,776	$ 3,366,958
		Sub-Total	**$ 163,332,418**	**$ -**	**$ -**			**$ 163,332,418**	**$ -**	**$ 42,209,093**	**$ -**	**$ -**			**$ 42,209,093**	**$ 205,541,510**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -							$ -	$ -
		Total PP&E	**$ 163,332,418**	**$ -**	**$ -**			**$ 163,332,418**		**$ 42,209,093**	**$ -**	**$ -**			**$ 42,209,093**	**$ 205,541,510**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
		Total									**$ -**					

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**$ -**

Appendix D – Bill Impacts Settlement

0% VVO Model

Ontario Energy Board

Tariff Schedule and Bill Impacts Model

(2023 Cost of Service Filers)

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2017 of $0.1036/kWh (IESO's Monthly Market Report for May 2017, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	2,000		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0481	1.0462	57,220	145	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	3,600		CONSUMPTION	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kw	RPP	1.0481	1.0462	50	1	DEMAND	
STREET LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Retailer)	1.0481	1.0462	199,852	566	DEMAND	8,037
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION			1.0481	1.0462				
STANDBY POWER SERVICE CLASSIFICATION			1.0481	1.0462				
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	318		CONSUMPTION	
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 4.01	11.3%	$ 3.80	9.7%	$ 4.26	9.3%	$ 4.31	3.6%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ 5.87	7.3%	$ 5.52	6.2%	$ 6.74	6.4%	$ 6.81	2.2%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 162.53	13.1%	$ (54.94)	-3.9%	$ (22.60)	-1.2%	$ (37.55)	-0.4%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ 18.73	11.0%	$ 18.10	9.7%	$ 20.30	9.4%	$ 20.53	3.6%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	$ 4.62	11.1%	$ 4.58	10.9%	$ 4.75	10.7%	$ 4.81	9.6%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$ 2,874.78	15.8%	$ 2,117.33	11.2%	$ 2,212.53	11.0%	$ 2,241.29	5.4%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION -									
STANDBY POWER SERVICE CLASSIFICATION -									
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	**750** kWh
Demand	**-** kW
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0462**

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 33.72	1	$ 33.72	$ 38.35	1	$ 38.35	$ 4.63	13.73%	
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -		
Fixed Rate Riders	$ 1.82	1	$ 1.82	$ 1.05	1	$ 1.05	$ (0.77)	-42.31%	
Volumetric Rate Riders	$ -	750	$ -	$ 0.0002	750	$ 0.15	$ 0.15		
Sub-Total A (excluding pass through)			**$ 35.54**			**$ 39.55**	**$ 4.01**	**11.28%**	
Line Losses on Cost of Power	$ 0.0926	36	$ 3.34	$ 0.0926	35	$ 3.21	$ (0.13)	-3.95%	
Total Deferral/Variance Account Rate Riders	$ 0.0003	750	$ 0.23	$ 0.0002	750	$ 0.15	$ (0.08)	-33.33%	
CBR Class B Rate Riders	$ (0.0001)	750	$ (0.08)	$ (0.0001)	750	$ (0.08)	$ -	0.00%	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Low Voltage Service Charge	$ -	750	$ -		750	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ (0.0004)	750	$ (0.30)	$ (0.0004)	750	$ (0.30)	$ -	0.00%	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 39.15**			**$ 42.95**	**$ 3.80**	**9.71%**	
RTSR - Network	$ 0.0086	786	$ 6.76	$ 0.0092	785	$ 7.22	$ 0.46	6.78%	In the manager's summary, discuss the reas
RTSR - Connection and/or Line and Transformation Connection	$ -	786	$ -	$ -	785	$ -	$ -		
Sub-Total C - Delivery (including Sub-Total B)			**$ 45.91**			**$ 50.17**	**$ 4.26**	**9.28%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	786	$ 3.54	$ 0.0045	785	$ 3.53	$ (0.01)	-0.18%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	786	$ 0.55	$ 0.0007	785	$ 0.55	$ (0.00)	-0.18%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0740	488	$ 36.08	$ 0.0740	488	$ 36.08	$ -	0.00%	
TOU - Mid Peak	$ 0.1020	128	$ 13.01	$ 0.1020	128	$ 13.01	$ -	0.00%	
TOU - On Peak	$ 0.1510	135	$ 20.39	$ 0.1510	135	$ 20.39	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 119.71**			**$ 123.97**	**$ 4.25**	**3.55%**	
HST	13%		$ 15.56	13%		$ 16.12	$ 0.55	3.55%	
Ontario Electricity Rebate	11.7%		$ (14.01)	11.7%		$ (14.50)	$ (0.50)		
Total Bill on TOU			**$ 121.27**			**$ 125.58**	**$ 4.31**	**3.55%**	

Customer Class:	**GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**2,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0462**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 22.32	1	$ 22.32	$ 22.32	1	$ 22.32	$ -	0.00%
Distribution Volumetric Rate	$ 0.0268	2000	$ 53.60	$ 0.0319	2000	$ 63.80	$ 10.20	19.03%
Fixed Rate Riders	$ 1.21	1	$ 1.21	$ 2.48	1	$ 2.48	$ 1.27	104.96%
Volumetric Rate Riders	$ 0.0014	2000	$ 2.80	$ (0.0014)	2000	$ (2.80)	$ (5.60)	-200.00%
Sub-Total A (excluding pass through)			**$ 79.93**			**$ 85.80**	**$ 5.87**	**7.34%**
Line Losses on Cost of Power	$ 0.0926	96	$ 8.91	$ 0.0926	92	$ 8.56	$ (0.35)	-3.95%
Total Deferral/Variance Account Rate Riders	$ 0.0003	2,000	$ 0.60	$ 0.0003	2,000	$ 0.60	$ -	0.00%
CBR Class B Rate Riders	$ (0.0001)	2,000	$ (0.20)	$ (0.0001)	2,000	$ (0.20)	$ -	0.00%
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	2,000	$ (0.80)	$ (0.0004)	2,000	$ (0.80)	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 88.86**			**$ 94.38**	**$ 5.52**	**6.21%**
RTSR - Network	$ 0.0080	2,096	$ 16.77	$ 0.0086	2,092	$ 17.99	$ 1.23	7.31%
RTSR - Connection and/or Line and Transformation Connection	$ -	2,096	$ -	$ -	2,092	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 105.63**			**$ 112.37**	**$ 6.74**	**6.38%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,096	$ 9.43	$ 0.0045	2,092	$ 9.42	$ (0.02)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	2,096	$ 1.47	$ 0.0007	2,092	$ 1.46	$ (0.00)	-0.18%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	1,300	$ 96.20	$ 0.0740	1,300	$ 96.20	$ -	0.00%
TOU - Mid Peak	$ 0.1020	340	$ 34.68	$ 0.1020	340	$ 34.68	$ -	0.00%
TOU - On Peak	$ 0.1510	360	$ 54.36	$ 0.1510	360	$ 54.36	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 302.02**			**$ 308.74**	**$ 6.72**	**2.23%**
HST	13%		$ 39.26	13%		$ 40.14	$ 0.87	2.23%
Ontario Electricity Rebate	11.7%		$ (35.34)	11.7%		$ (36.12)	$ (0.79)	
Total Bill on TOU			**$ 305.95**			**$ 312.76**	**$ 6.81**	**2.23%**

In the manager's summary, discuss the reas

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	**1.0481**
Proposed/Approved Loss Factor	**1.0462**

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 123.27	1	$ 123.27	$ 123.27	1	$ 123.27	$ -	0.00%	
Distribution Volumetric Rate	$ 7.2479	145	$ 1,050.95	$ 8.3565	145	$ 1,211.69	$ 160.75	15.30%	
Fixed Rate Riders	$ 6.65	1	$ 6.65	$ 24.75	1	$ 24.75	$ 18.10	272.18%	
Volumetric Rate Riders	$ 0.3914	145	$ 56.75	$ 0.2789	145	$ 40.44	$ (16.31)	-28.74%	
Sub-Total A (excluding pass through)			**$ 1,237.62**			**$ 1,400.15**	**$ 162.53**	**13.13%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ 0.1286	145	$ 18.65	$ 0.1195	145	$ 17.33	$ (1.32)	-7.08%	
CBR Class B Rate Riders	$ (0.0234)	145	$ (3.39)	$ (0.0540)	145	$ (7.83)	$ (4.44)	130.77%	
GA Rate Riders	$ 0.0033	57,220	$ 188.83	$ (0.0004)	57,220	$ (22.89)	$ (211.71)	-112.12%	
Low Voltage Service Charge	$ -	145	$ -		145	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ (0.0004)	57,220	$ (22.89)	$ (0.0004)	57,220	$ (22.89)	$ -	0.00%	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,418.81**			**$ 1,363.87**	**$ (54.94)**	**-3.87%**	
RTSR - Network	$ 3.2337	145	$ 468.89	$ 3.4567	145	$ 501.22	$ 32.34	6.90%	In the manager's summary, discuss the reas
RTSR - Connection and/or Line and Transformation Connection	$ -	145	$ -	$ -	145	$ -	$ -		
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,887.70**			**$ 1,865.10**	**$ (22.60)**	**-1.20%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	59,972	$ 269.88	$ 0.0045	59,864	$ 269.39	$ (0.49)	-0.18%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	59,972	$ 41.98	$ 0.0007	59,864	$ 41.90	$ (0.08)	-0.18%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.0926	59,972	$ 5,553.43	$ 0.0926	59,864	$ 5,543.37	$ (10.07)	-0.18%	
Total Bill on Average IESO Wholesale Market Price			**$ 7,753.24**			**$ 7,720.00**	**$ (33.23)**	**-0.43%**	
HST	13%		$ 1,007.92	13%		$ 1,003.60	$ (4.32)	-0.43%	
Ontario Electricity Rebate	11.7%		$ -	11.7%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 8,761.16**			**$ 8,723.60**	**$ (37.55)**	**-0.43%**	

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	3,600 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 13.67	1	$ 13.67	$ 13.67	1	$ 13.67	$ -	0.00%
Distribution Volumetric Rate	$ 0.0412	3600	$ 148.32	$ 0.0476	3600	$ 171.36	$ 23.04	15.53%
Fixed Rate Riders	$ 0.74	1	$ 0.74	$ 2.91	1	$ 2.91	$ 2.17	293.24%
Volumetric Rate Riders	$ 0.0023	3600	$ 8.28	$ 0.0005	3600	$ 1.80	$ (6.48)	-78.26%
Sub-Total A (excluding pass through)			**$ 171.01**			**$ 189.74**	**$ 18.73**	**10.95%**
Line Losses on Cost of Power	$ 0.0926	173	$ 16.04	$ 0.0926	166	$ 15.40	$ (0.63)	-3.95%
Total Deferral/Variance Account Rate Riders	$ 0.0003	3,600	$ 1.08	$ 0.0003	3600	$ 1.08	$ -	0.00%
CBR Class B Rate Riders	$ (0.0001)	3,600	$ (0.36)	$ (0.0001)	3600	$ (0.36)	$ -	0.00%
GA Rate Riders	$ -	3,600	$ -	$ -	3600	$ -	$ -	
Low Voltage Service Charge	$ -	3,600	$ -		3600	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	3,600	$ (1.44)	$ (0.0004)	3600	$ (1.44)	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 186.33**			**$ 204.42**	**$ 18.10**	**9.71%**
RTSR - Network	$ 0.0080	3,773	$ 30.19	$ 0.0086	3,766	$ 32.39	$ 2.21	7.31%
RTSR - Connection and/or Line and Transformation Connection	$ -	3,773	$ -	$ -	3,766	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 216.51**			**$ 236.81**	**$ 20.30**	**9.38%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	3,773	$ 16.98	$ 0.0045	3,766	$ 16.95	$ (0.03)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	3,773	$ 2.64	$ 0.0007	3,766	$ 2.64	$ (0.00)	-0.18%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	2,340	$ 173.16	$ 0.0740	2,340	$ 173.16	$ -	0.00%
TOU - Mid Peak	$ 0.1020	612	$ 62.42	$ 0.1020	612	$ 62.42	$ -	0.00%
TOU - On Peak	$ 0.1510	648	$ 97.85	$ 0.1510	648	$ 97.85	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 569.82**			**$ 590.08**	**$ 20.27**	**3.56%**
HST	13%		$ 74.08	13%		$ 76.71	$ 2.63	3.56%
Ontario Electricity Rebate	11.7%		$ (66.67)	11.7%		$ (69.04)	$ (2.37)	
Total Bill on TOU			**$ 577.22**			**$ 597.75**	**$ 20.53**	**3.56%**

In the manager's summary, discuss the reas

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	50	kWh
Demand	1	kW
Current Loss Factor	1.0481	
Proposed/Approved Loss Factor	1.0462	

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 3.83	1	$ 3.83	$ 4.35	1	$ 4.35	$ 0.52	13.58%	
Distribution Volumetric Rate	$ 35.7037	1	$ 35.70	$ 40.6108	1	$ 40.61	$ 4.91	13.74%	
Fixed Rate Riders	$ 0.20	1	$ 0.20	$ 0.39	1	$ 0.39	$ 0.19	95.00%	
Volumetric Rate Riders	$ 1.9278	1	$ 1.93	$ 0.9344	1	$ 0.93	$ (0.99)	-51.53%	
Sub-Total A (excluding pass through)			**$ 41.66**			**$ 46.29**	**$ 4.62**	**11.10%**	
Line Losses on Cost of Power	$ 0.0926	2	$ 0.22	$ 0.0926	2	$ 0.21	$ (0.01)	-3.95%	
Total Deferral/Variance Account Rate Riders	$ 0.1057	1	$ 0.11	$ 0.1012	1	$ 0.10	$ (0.00)	-4.26%	
CBR Class B Rate Riders	$ (0.0201)	1	$ (0.02)	$ (0.0462)	1	$ (0.05)	$ (0.03)	129.85%	
GA Rate Riders	$ -	50	$ -	$ -	49	$ -	$ -		
Low Voltage Service Charge	$ -	1	$ -		1	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ (0.0004)	50	$ (0.02)	$ (0.0004)	49	$ (0.02)	$ 0.00	-2.70%	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 41.95**			**$ 46.53**	**$ 4.58**	**10.93%**	
RTSR - Network	$ 2.4511	1	$ 2.45	$ 2.6202	1	$ 2.62	$ 0.17	6.90%	In the manager's summary, discuss the reas
RTSR - Connection and/or Line and Transformation Connection	$ -	1	$ -	$ -	1	$ -	$ -		
Sub-Total C - Delivery (including Sub-Total B)			**$ 44.40**			**$ 49.15**	**$ 4.75**	**10.71%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	52	$ 0.24	$ 0.0045	52	$ 0.24	$ (0.00)	-0.18%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	52	$ 0.04	$ 0.0007	52	$ 0.04	$ (0.00)	-0.18%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0740	33	$ 2.41	$ 0.0740	33	$ 2.41	$ -	0.00%	
TOU - Mid Peak	$ 0.1020	9	$ 0.87	$ 0.1020	9	$ 0.87	$ -	0.00%	
TOU - On Peak	$ 0.1510	9	$ 1.36	$ 0.1510	9	$ 1.36	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 49.55**			**$ 54.31**	**$ 4.75**	**9.59%**	
HST	13%		$ 6.44	13%		$ 7.06	$ 0.62	9.59%	
Ontario Electricity Rebate	11.7%		$ (5.80)	11.7%		$ (6.35)	$ (0.56)		
Total Bill on TOU			**$ 50.20**			**$ 55.01**	**$ 4.82**	**9.59%**	

Customer Class:	**STREET LIGHTING SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**199,852 kWh**
Demand	**566 kW**
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0462**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 1.47	8037	$ 11,814.39	$ 1.67	8037	$ 13,421.79	$ 1,607.40	13.61%
Distribution Volumetric Rate	$ 9.6161	566	$ 5,442.71	$ 10.9378	566	$ 6,190.79	$ 748.08	13.74%
Fixed Rate Riders	$ 0.08	8037	$ 642.96	$ 0.13	8037	$ 1,044.81	$ 401.85	62.50%
Volumetric Rate Riders	$ 0.5192	566	$ 293.87	$ 0.7267	566	$ 411.31	$ 117.45	39.97%
Sub-Total A (excluding pass through)			**$ 18,193.93**			**$ 21,068.71**	**$ 2,874.78**	**15.80%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.1061	566	$ 60.05	$ 0.1010	566	$ 57.17	$ (2.89)	-4.81%
CBR Class B Rate Riders	$ (0.0194)	566	$ (10.98)	$ (0.0461)	566	$ (26.09)	$ (15.11)	137.63%
GA Rate Riders	$ 0.0033	199,852	$ 659.51	$ (0.0004)	199,852	$ (79.94)	$ (739.45)	-112.12%
Low Voltage Service Charge	$ -	566	$ -		566	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	199,852	$ (79.94)	$ (0.0004)	199,852	$ (79.94)	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 18,822.57**			**$ 20,939.90**	**$ 2,117.33**	**11.25%**
RTSR - Network	$ 2.4391	566	$ 1,380.53	$ 2.6073	566	$ 1,475.73	$ 95.20	6.90%
RTSR - Connection and/or Line and Transformation Connection	$ -	566	$ -	$ -	566	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 20,203.10**			**$ 22,415.63**	**$ 2,212.53**	**10.95%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	209,465	$ 942.59	$ 0.0045	209,465	$ 942.59	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	209,465	$ 146.63	$ 0.0007	209,465	$ 146.63	$ -	0.00%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.0926	209,465	$ 19,396.45	$ 0.0926	209,465	$ 19,396.45	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 40,688.77**			**$ 42,901.30**	**$ 2,212.53**	**5.44%**
HST	13%		$ 5,289.54	13%		$ 5,577.17	$ 287.63	5.44%
Ontario Electricity Rebate	11.7%		$ (4,760.59)	11.7%		$ (5,019.45)		
Total Bill on Non-RPP Avg. Price			**$ 41,217.72**			**$ 43,459.01**	**$ 2,241.29**	**5.44%**

In the manager's summary, discuss the reas

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	0
Consumption	- kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 13.67		$ -	$ 13.67	0	$ -	$ -	
Distribution Volumetric Rate	$ 0.0412	0	$ -	$ 0.0476	0	$ -	$ -	
Fixed Rate Riders	$ 0.74	1	$ 0.74	$ 2.92	1	$ 2.92	$ 2.18	294.59%
Volumetric Rate Riders	$ 0.0023	0	$ -	$ 0.0002	0	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 0.74**			**$ 2.92**	**$ 2.18**	**294.59%**
Line Losses on Cost of Power	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.0003	-	$ -	$ 0.0003	-	$ -	$ -	
CBR Class B Rate Riders	$ (0.0001)	-	$ -	$ -	-	$ -	$ -	
GA Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
Low Voltage Service Charge	$ -	-	$ -		-	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		-	$ -	$ (0.0002)	-	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 0.74**			**$ 2.92**	**$ 2.18**	**294.59%**
RTSR - Network	$ 0.0080	-	$ -	$ 0.0086	-	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	-	$ -	$ -	-	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 0.74**			**$ 2.92**	**$ 2.18**	**294.59%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	-	$ -	$ 0.0045	-	$ -	$ -	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	-	$ -	$ 0.0007	-	$ -	$ -	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	-	$ -	$ 0.0740	-	$ -	$ -	
TOU - Mid Peak	$ 0.1020	-	$ -	$ 0.1020	-	$ -	$ -	
TOU - On Peak	$ 0.1510	-	$ -	$ 0.1510	-	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 0.99**			**$ 3.17**	**$ 2.18**	**220.20%**
HST	13%		$ 0.13	13%		$ 0.41	$ 0.28	220.20%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -	$ -	
Total Bill on TOU			**$ 1.12**			**$ 3.58**	**$ 2.46**	**220.20%**
Total Bill on Non-RPP Avg. Price			**$ 0.99**			**$ 3.17**	**$ 2.18**	**220.20%**
HST	13%		$ 0.13	13%		$ 0.41	$ 0.28	220.20%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Non-RPP Avg. Price			**$ 1.12**			**$ 3.58**	**$ 2.46**	**220.20%**
Total Bill on Average IESO Wholesale Market Price			**$ 0.99**			**$ 3.17**	**$ 2.18**	**220.20%**
HST	13%		$ 0.13	13%		$ 0.41	$ 0.28	220.20%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 1.12**			**$ 3.58**	**$ 2.46**	**220.20%**

Customer Class:	STANDBY POWER SERVICE CLASSIFICATION
RPP / Non-RPP:	0
Consumption	- kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	$ -	0	$ -	$ -	0	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	0	$ -	$ -	0	$ -	$ -	
Sub-Total A (excluding pass through)			**$ -**			$ -	**$ -**	
Line Losses on Cost of Power	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
CBR Class B Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
GA Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
Low Voltage Service Charge	$ -	-	$ -		-	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		-	$ -	$ -	-	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ -**			$ -	**$ -**	
RTSR - Network	$ -	-	$ -	$ -	-	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	-	$ -	$ -	-	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ -**			$ -	**$ -**	
Wholesale Market Service Charge (WMSC)	$ -	-	$ -	$ -	-	$ -	$ -	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	-	$ -	$ -	-	$ -	$ -	
Standard Supply Service Charge	$ -	1	$ -	$ 0.25	1	$ 0.25	$ 0.25	
TOU - Off Peak	$ 0.0740	-	$ -	$ 0.0740	-	$ -	$ -	
TOU - Mid Peak	$ 0.1020	-	$ -	$ 0.1020	-	$ -	$ -	
TOU - On Peak	$ 0.1510	-	$ -	$ 0.1510	-	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ -**			**$ 0.25**	**$ 0.25**	
HST	13%		$ -	13%		$ 0.03	$ 0.03	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -	$ -	
Total Bill on TOU			**$ -**			**$ 0.28**	**$ 0.28**	
Total Bill on Non-RPP Avg. Price			**$ -**			**$ 0.25**	**$ 0.25**	
HST	13%		$ -	13%		$ 0.03	$ 0.03	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Non-RPP Avg. Price			**$ -**			**$ 0.28**	**$ 0.28**	
Total Bill on Average IESO Wholesale Market Price			**$ -**			**$ 0.25**	**$ 0.25**	
HST	13%		$ -	13%		$ 0.03	$ 0.03	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ -**			**$ 0.28**	**$ 0.28**	

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	318 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 33.72	1	$ 33.72	$ 38.35	1	$ 38.35	$ 4.63	13.73%
Distribution Volumetric Rate	$ -	318	$ -	$ -	318	$ -	$ -	
Fixed Rate Riders	$ 1.82	1	$ 1.82	$ 0.89	1	$ 0.89	$ (0.93)	-51.10%
Volumetric Rate Riders	$ -	318	$ -	$ 0.0002	318	$ 0.06	$ 0.06	
Sub-Total A (excluding pass through)			**$ 35.54**			**$ 39.30**	**$ 3.76**	**10.59%**
Line Losses on Cost of Power	$ 0.0926	15	$ 1.42	$ 0.0926	15	$ 1.36	$ (0.06)	-3.95%
Total Deferral/Variance Account Rate Riders	$ 0.0003	318	$ 0.10	$ 0.0002	318	$ 0.06	$ (0.03)	-33.33%
CBR Class B Rate Riders	$ (0.0001)	318	$ (0.03)	$ -	318	$ -	$ 0.03	-100.00%
GA Rate Riders	$ -	318	$ -	$ -	318	$ -	$ -	
Low Voltage Service Charge	$ -	318	$ -		318	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		318	$ -	$ (0.0002)	318	$ (0.06)	$ (0.06)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 37.44**			**$ 41.08**	**$ 3.64**	**9.73%**
RTSR - Network	$ 0.0086	333	$ 2.87	$ 0.0092	333	$ 3.06	$ 0.19	6.78%
RTSR - Connection and/or Line and Transformation Connection	$ -	333	$ -	$ -	333	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 40.31**			**$ 44.15**	**$ 3.84**	**9.52%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	333	$ 1.13	$ 0.0045	333	$ 1.50	$ 0.36	32.11%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	333	$ 0.23	$ 0.0007	333	$ 0.23	$ (0.00)	-0.18%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	207	$ 15.30	$ 0.0740	207	$ 15.30	$ -	0.00%
TOU - Mid Peak	$ 0.1020	54	$ 5.51	$ 0.1020	54	$ 5.51	$ -	0.00%
TOU - On Peak	$ 0.1510	57	$ 8.64	$ 0.1510	57	$ 8.64	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 71.38**			**$ 75.58**	**$ 4.20**	**5.89%**
HST	13%		$ 9.28	13%		$ 9.83	$ 0.55	5.89%
Ontario Electricity Rebate	17.0%		$ (12.13)	17.0%		$ (12.85)	$ (0.71)	
Total Bill on TOU			**$ 68.52**			**$ 72.56**	**$ 4.03**	**5.89%**

In the manager's summary, discuss the reas

2.7% VVO Model

Ontario Energy Board

Tariff Schedule and Bill Impacts Model

(2023 Cost of Service Filers)

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2017 of $0.1036/kWh (IESO's Monthly Market Report for May 2017, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	2,000		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0481	1.0462	57,220	145	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	3,600		CONSUMPTION	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kw	RPP	1.0481	1.0462	50	1	DEMAND	
STREET LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Retailer)	1.0481	1.0462	199,852	566	DEMAND	8,037
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION			1.0481	1.0462				
STANDBY POWER SERVICE CLASSIFICATION			1.0481	1.0462				
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	318		CONSUMPTION	
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**Sub-Total**						**Total**	
		A		**B**		**C**		**Total Bill**	
		$	**%**	**$**	**%**	**$**	**%**	**$**	**%**
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 4.01	11.3%	$ 3.81	9.7%	$ 4.07	8.9%	$ 2.10	1.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ 4.22	5.3%	$ 3.65	4.1%	$ 4.39	4.2%	$ (0.94)	-0.3%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 128.73	10.4%	$ (87.76)	-6.2%	$ (68.96)	-3.7%	$ (268.57)	-3.1%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ 14.05	8.2%	$ 13.02	7.0%	$ 14.36	6.6%	$ 4.85	0.8%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	$ 4.62	11.1%	$ 4.58	10.9%	$ 4.75	10.7%	$ 4.69	9.3%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$ 2,874.78	15.8%	$ 2,121.64	11.3%	$ 2,216.84	11.0%	$ 1,685.36	4.1%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION -									
STANDBY POWER SERVICE CLASSIFICATION -									
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	**750** kWh
Demand	**-** kW
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0462**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 33.72	1	$ 33.72	$ 38.35	1	$ 38.35	$ 4.63	13.73%
Distribution Volumetric Rate	$ -	750	$ -	$ -	730	$ -	$ -	
Fixed Rate Riders	$ 1.82	1	$ 1.82	$ 1.05	1	$ 1.05	$ (0.77)	-42.31%
Volumetric Rate Riders	$ -	750	$ -	$ 0.0002	730	$ 0.15	$ 0.15	
Sub-Total A (excluding pass through)			**$ 35.54**			**$ 39.55**	**$ 4.01**	**11.27%**
Line Losses on Cost of Power	$ 0.0926	36	$ 3.34	$ 0.0926	35	$ 3.21	$ (0.13)	-3.95%
Total Deferral/Variance Account Rate Riders	$ 0.0003	750	$ 0.23	$ 0.0002	730	$ 0.15	$ (0.08)	-35.13%
CBR Class B Rate Riders	$ (0.0001)	750	$ (0.08)	$ (0.0001)	730	$ (0.07)	$ 0.00	-2.70%
GA Rate Riders	$ -	750	$ -	$ -	730	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		730	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	750	$ (0.30)	$ (0.0004)	730	$ (0.29)	$ 0.01	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 39.15**			**$ 42.96**	**$ 3.81**	**9.72%**
RTSR - Network	$ 0.0086	786	$ 6.76	$ 0.0092	763	$ 7.02	$ 0.26	3.90%
RTSR - Connection and/or Line and Transformation Connection	$ -	786	$ -	$ -	763	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 45.91**			**$ 49.98**	**$ 4.07**	**8.86%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	786	$ 3.54	$ 0.0045	763	$ 3.44	$ (0.10)	-2.88%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	786	$ 0.55	$ 0.0007	763	$ 0.53	$ (0.02)	-2.88%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	488	$ 36.08	$ 0.0740	474	$ 35.10	$ (0.97)	-2.70%
TOU - Mid Peak	$ 0.1020	128	$ 13.01	$ 0.1020	124	$ 12.65	$ (0.35)	-2.70%
TOU - On Peak	$ 0.1510	135	$ 20.39	$ 0.1510	131	$ 19.83	$ (0.55)	-2.70%
Total Bill on TOU (before Taxes)			**$ 119.71**			**$ 121.79**	**$ 2.08**	**1.73%**
HST	13%		$ 15.56	13%		$ 15.83	$ 0.27	1.73%
Ontario Electricity Rebate	11.7%		$ (14.01)	11.7%		$ (14.25)	$ (0.24)	
Total Bill on TOU			**$ 121.27**			**$ 123.37**	**$ 2.10**	**1.73%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 22.32	1	$ 22.32	$ 22.32	1	$ 22.32	$ -	0.00%	
Distribution Volumetric Rate	$ 0.0268	2000	$ 53.60	$ 0.0319	1946	$ 62.08	$ 8.48	15.82%	
Fixed Rate Riders	$ 1.21	1	$ 1.21	$ 2.48	1	$ 2.48	$ 1.27	104.96%	
Volumetric Rate Riders	$ 0.0014	2000	$ 2.80	$ (0.0014)	1946	$ (2.72)	$ (5.52)	-197.30%	
Sub-Total A (excluding pass through)			**$ 79.93**			**$ 84.15**	**$ 4.22**	**5.28%**	
Line Losses on Cost of Power	$ 0.0926	96	$ 8.91	$ 0.0926	90	$ 8.33	$ (0.58)	-6.54%	
Total Deferral/Variance Account Rate Riders	$ 0.0003	2,000	$ 0.60	$ 0.0003	1946	$ 0.58	$ (0.02)	-2.70%	
CBR Class B Rate Riders	$ (0.0001)	2,000	$ (0.20)	$ (0.0001)	1946	$ (0.19)	$ 0.01	-2.70%	
GA Rate Riders	$ -	2,000	$ -	$ -	1946	$ -	$ -		
Low Voltage Service Charge	$ -	2,000	$ -		1946	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ (0.0004)	2,000	$ (0.80)	$ (0.0004)	1946	$ (0.78)	$ 0.02	-2.70%	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 88.86**			**$ 92.51**	**$ 3.65**	**4.11%**	
RTSR - Network	$ 0.0080	2,096	$ 16.77	$ 0.0086	2,036	$ 17.51	$ 0.74	4.41%	In the manager's summary, discuss the reas
RTSR - Connection and/or Line and Transformation Connection	$ -	2,096	$ -	$ -	2,036	$ -	$ -		
Sub-Total C - Delivery (including Sub-Total B)			**$ 105.63**			**$ 110.02**	**$ 4.39**	**4.16%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,096	$ 9.43	$ 0.0045	2,036	$ 9.16	$ (0.27)	-2.88%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	2,096	$ 1.47	$ 0.0007	2,036	$ 1.43	$ (0.04)	-2.88%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0740	1,300	$ 96.20	$ 0.0740	1,265	$ 93.60	$ (2.60)	-2.70%	
TOU - Mid Peak	$ 0.1020	340	$ 34.68	$ 0.1020	331	$ 33.74	$ (0.94)	-2.70%	
TOU - On Peak	$ 0.1510	360	$ 54.36	$ 0.1510	350	$ 52.89	$ (1.47)	-2.70%	
Total Bill on TOU (before Taxes)			**$ 302.02**			**$ 301.09**	**$ (0.93)**	**-0.31%**	
HST	13%		$ 39.26	13%		$ 39.14	$ (0.12)	-0.31%	
Ontario Electricity Rebate	11.7%		$ (35.34)	11.7%		$ (35.23)	$ 0.11		
Total Bill on TOU			**$ 305.95**			**$ 305.01**	**$ (0.94)**	**-0.31%**	

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	**1.0481**
Proposed/Approved Loss Factor	**1.0462**

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 123.27	1	$ 123.27	$ 123.27	1	$ 123.27	$ -	0.00%	
Distribution Volumetric Rate	$ 7.2479	145	$ 1,050.95	$ 8.3565	141	$ 1,178.98	$ 128.03	12.18%	
Fixed Rate Riders	$ 6.65	1	$ 6.65	$ 24.75	1	$ 24.75	$ 18.10	272.18%	
Volumetric Rate Riders	$ 0.3914	145	$ 56.75	$ 0.2789	141	$ 39.35	$ (17.40)	-30.67%	
Sub-Total A (excluding pass through)			**$ 1,237.62**			**$ 1,366.35**	**$ 128.73**	**10.40%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ 0.1286	145	$ 18.65	$ 0.1195	141	$ 16.86	$ (1.79)	-9.59%	
CBR Class B Rate Riders	$ (0.0234)	145	$ (3.39)	$ (0.0540)	141	$ (7.62)	$ (4.23)	124.54%	
GA Rate Riders	$ 0.0033	57,220	$ 188.83	$ (0.0004)	55,675	$ (22.27)	$ (211.10)	-111.79%	
Low Voltage Service Charge	$ -	145	$ -		141	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ (0.0004)	57,220	$ (22.89)	$ (0.0004)	55,675	$ (22.27)	$ 0.62	-2.70%	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,418.81**			**$ 1,331.05**	**$ (87.76)**	**-6.19%**	
RTSR - Network	$ 3.2337	145	$ 468.89	$ 3.4567	141	$ 487.69	$ 18.80	4.01%	In the manager's summary, discuss the reas
RTSR - Connection and/or Line and Transformation Connection	$ -	145	$ -	$ -	141	$ -	$ -		
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,887.70**			**$ 1,818.73**	**$ (68.96)**	**-3.65%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	59,972	$ 269.88	$ 0.0045	58,247	$ 262.11	$ (7.76)	-2.88%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	59,972	$ 41.98	$ 0.0007	58,247	$ 40.77	$ (1.21)	-2.88%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.0926	59,972	$ 5,553.43	$ 0.0926	58,247	$ 5,393.70	$ (159.74)	-2.88%	
Total Bill on Average IESO Wholesale Market Price			**$ 7,753.24**			**$ 7,515.57**	**$ (237.67)**	**-3.07%**	
HST	13%		$ 1,007.92	13%		$ 977.02	$ (30.90)	-3.07%	
Ontario Electricity Rebate	11.7%		$ -	11.7%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 8,761.16**			**$ 8,492.59**	**$ (268.57)**	**-3.07%**	

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	**3,600** kWh
Demand	**-** kW
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0462**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 13.67	1	$ 13.67	$ 13.67	1	$ 13.67	$ -	0.00%
Distribution Volumetric Rate	$ 0.0412	3600	$ 148.32	$ 0.0476	3503	$ 166.73	$ 18.41	12.41%
Fixed Rate Riders	$ 0.74	1	$ 0.74	$ 2.91	1	$ 2.91	$ 2.17	293.24%
Volumetric Rate Riders	$ 0.0023	3600	$ 8.28	$ 0.0005	3503	$ 1.75	$ (6.53)	-78.85%
Sub-Total A (excluding pass through)			**$ 171.01**			**$ 185.06**	**$ 14.05**	**8.22%**
Line Losses on Cost of Power	$ 0.0926	173	$ 16.04	$ 0.0926	162	$ 14.99	$ (1.05)	-6.54%
Total Deferral/Variance Account Rate Riders	$ 0.0003	3,600	$ 1.08	$ 0.0003	3503	$ 1.05	$ (0.03)	-2.70%
CBR Class B Rate Riders	$ (0.0001)	3,600	$ (0.36)	$ (0.0001)	3503	$ (0.35)	$ 0.01	-2.70%
GA Rate Riders	$ -	3,600	$ -	$ -	3503	$ -	$ -	
Low Voltage Service Charge	$ -	3,600	$ -		3503	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	3,600	$ (1.44)	$ (0.0004)	3503	$ (1.40)	$ 0.04	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 186.33**			**$ 199.35**	**$ 13.02**	**6.99%**
RTSR - Network	$ 0.0080	3,773	$ 30.19	$ 0.0086	3,665	$ 31.52	$ 1.33	4.41%
RTSR - Connection and/or Line and Transformation Connection	$ -	3,773	$ -	$ -	3,665	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 216.51**			**$ 230.87**	**$ 14.36**	**6.63%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	3,773	$ 16.98	$ 0.0045	3,665	$ 16.49	$ (0.49)	-2.88%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	3,773	$ 2.64	$ 0.0007	3,665	$ 2.57	$ (0.08)	-2.88%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	2,340	$ 173.16	$ 0.0740	2,277	$ 168.48	$ (4.68)	-2.70%
TOU - Mid Peak	$ 0.1020	612	$ 62.42	$ 0.1020	595	$ 60.74	$ (1.69)	-2.70%
TOU - On Peak	$ 0.1510	648	$ 97.85	$ 0.1510	631	$ 95.21	$ (2.64)	-2.70%
Total Bill on TOU (before Taxes)			**$ 569.82**			**$ 574.60**	**$ 4.79**	**0.84%**
HST	13%		$ 74.08	13%		$ 74.70	$ 0.62	0.84%
Ontario Electricity Rebate	11.7%		$ (66.67)	11.7%		$ (67.23)	$ (0.56)	
Total Bill on TOU			**$ 577.22**			**$ 582.07**	**$ 4.85**	**0.84%**

In the manager's summary, discuss the reas

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	50 kWh
Demand	1 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 3.83	1	$ 3.83	$ 4.35	1	$ 4.35	$ 0.52	13.58%	
Distribution Volumetric Rate	$ 35.7037	1	$ 35.70	$ 40.6108	1	$ 40.61	$ 4.91	13.74%	
Fixed Rate Riders	$ 0.20	1	$ 0.20	$ 0.39	1	$ 0.39	$ 0.19	95.00%	
Volumetric Rate Riders	$ 1.9278	1	$ 1.93	$ 0.9344	1	$ 0.93	$ (0.99)	-51.53%	
Sub-Total A (excluding pass through)			**$ 41.66**			**$ 46.29**	**$ 4.62**	**11.10%**	
Line Losses on Cost of Power	$ 0.0926	2	$ 0.22	$ 0.0926	2	$ 0.21	$ (0.01)	-3.95%	
Total Deferral/Variance Account Rate Riders	$ 0.1057	1	$ 0.11	$ 0.1012	1	$ 0.10	$ (0.00)	-4.26%	
CBR Class B Rate Riders	$ (0.0201)	1	$ (0.02)	$ (0.0462)	1	$ (0.05)	$ (0.03)	129.85%	
GA Rate Riders	$ -	50	$ -	$ -	49	$ -	$ -		
Low Voltage Service Charge	$ -	1	$ -		1	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ (0.0004)	50	$ (0.02)	$ (0.0004)	49	$ (0.02)	$ 0.00	-2.70%	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 41.95**			**$ 46.53**	**$ 4.58**	**10.93%**	
RTSR - Network	$ 2.4511	1	$ 2.45	$ 2.6202	1	$ 2.62	$ 0.17	6.90%	In the manager's summary, discuss the reas
RTSR - Connection and/or Line and Transformation Connection	$ -	1	$ -	$ -	1	$ -	$ -		
Sub-Total C - Delivery (including Sub-Total B)			**$ 44.40**			**$ 49.15**	**$ 4.75**	**10.71%**	
Wholesale Market Service Charge (WMSC)	$ 0.0045	52	$ 0.24	$ 0.0045	52	$ 0.24	$ (0.00)	-0.18%	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	52	$ 0.04	$ 0.0007	52	$ 0.04	$ (0.00)	-0.18%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0740	33	$ 2.41	$ 0.0740	32	$ 2.34	$ (0.06)	-2.70%	
TOU - Mid Peak	$ 0.1020	9	$ 0.87	$ 0.1020	8	$ 0.84	$ (0.02)	-2.70%	
TOU - On Peak	$ 0.1510	9	$ 1.36	$ 0.1510	9	$ 1.32	$ (0.04)	-2.70%	
Total Bill on TOU (before Taxes)			**$ 49.55**			**$ 54.18**	**$ 4.63**	**9.34%**	
HST	13%		$ 6.44	13%		$ 7.04	$ 0.60	9.34%	
Ontario Electricity Rebate	11.7%		$ (5.80)	11.7%		$ (6.34)	$ (0.54)		
Total Bill on TOU			**$ 50.20**			**$ 54.89**	**$ 4.69**	**9.34%**	

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	199,852 kWh
Demand	566 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 1.47	8037	$ 11,814.39	$ 1.67	8037	$ 13,421.79	$ 1,607.40	13.61%
Distribution Volumetric Rate	$ 9.6161	566	$ 5,442.71	$ 10.9378	566	$ 6,190.79	$ 748.08	13.74%
Fixed Rate Riders	$ 0.08	8037	$ 642.96	$ 0.13	8037	$ 1,044.81	$ 401.85	62.50%
Volumetric Rate Riders	$ 0.5192	566	$ 293.87	$ 0.7267	566	$ 411.31	$ 117.45	39.97%
Sub-Total A (excluding pass through)			**$ 18,193.93**			**$ 21,068.71**	**$ 2,874.78**	**15.80%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.1061	566	$ 60.05	$ 0.1010	566	$ 57.17	$ (2.89)	-4.81%
CBR Class B Rate Riders	$ (0.0194)	566	$ (10.98)	$ (0.0461)	566	$ (26.09)	$ (15.11)	137.63%
GA Rate Riders	$ 0.0033	199,852	$ 659.51	$ (0.0004)	194,456	$ (77.78)	$ (737.29)	-111.79%
Low Voltage Service Charge	$ -	566	$ -		566	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	199,852	$ (79.94)	$ (0.0004)	194,456	$ (77.78)	$ 2.16	-2.70%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 18,822.57**			**$ 20,944.22**	**$ 2,121.64**	**11.27%**
RTSR - Network	$ 2.4391	566	$ 1,380.53	$ 2.6073	566	$ 1,475.73	$ 95.20	6.90%
RTSR - Connection and/or Line and Transformation Connection	$ -	566	$ -	$ -	566	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 20,203.10**			**$ 22,419.95**	**$ 2,216.84**	**10.97%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	209,465	$ 942.59	$ 0.0045	203,809	$ 917.14	$ (25.45)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	209,465	$ 146.63	$ 0.0007	203,809	$ 142.67	$ (3.96)	-2.70%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.0926	209,465	$ 19,396.45	$ 0.0926	203,809	$ 18,872.74	$ (523.70)	-2.70%
Total Bill on Non-RPP Avg. Price			**$ 40,688.77**			**$ 42,352.50**	**$ 1,663.73**	**4.09%**
HST	13%		$ 5,289.54	13%		$ 5,505.82	$ 216.29	4.09%
Ontario Electricity Rebate	11.7%		$ (4,760.59)	11.7%		$ (4,955.24)		
Total Bill on Non-RPP Avg. Price			**$ 41,217.72**			**$ 42,903.08**	**$ 1,685.36**	**4.09%**

In the manager's summary, discuss the reas

Customer Class: UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP: 0
Consumption - kWh
Demand - kW
Current Loss Factor 1.0481
Proposed/Approved Loss Factor 1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 13.67		$ -	$ 13.67	0	$ -	$ -	
Distribution Volumetric Rate	$ 0.0412	0	$ -	$ 0.0476	0	$ -	$ -	
Fixed Rate Riders	$ 0.74	1	$ 0.74	$ 2.92	1	$ 2.92	$ 2.18	294.59%
Volumetric Rate Riders	$ 0.0023	0	$ -	$ 0.0002	0	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 0.74**			**$ 2.92**	**$ 2.18**	**294.59%**
Line Losses on Cost of Power	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.0003	-	$ -	$ 0.0003	-	$ -	$ -	
CBR Class B Rate Riders	$ (0.0001)	-	$ -	$ -	-	$ -	$ -	
GA Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
Low Voltage Service Charge	$ -	-	$ -		-	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		-	$ -	$ (0.0002)	-	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 0.74**			**$ 2.92**	**$ 2.18**	**294.59%**
RTSR - Network	$ 0.0080	-	$ -	$ 0.0086	-	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	-	$ -	$ -	-	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 0.74**			**$ 2.92**	**$ 2.18**	**294.59%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	-	$ -	$ 0.0045	-	$ -	$ -	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	-	$ -	$ 0.0007	-	$ -	$ -	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	-	$ -	$ 0.0740	-	$ -	$ -	
TOU - Mid Peak	$ 0.1020	-	$ -	$ 0.1020	-	$ -	$ -	
TOU - On Peak	$ 0.1510	-	$ -	$ 0.1510	-	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 0.99**			**$ 3.17**	**$ 2.18**	**220.20%**
HST	13%		$ 0.13	13%		$ 0.41	$ 0.28	220.20%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -	$ -	
Total Bill on TOU			**$ 1.12**			**$ 3.58**	**$ 2.46**	**220.20%**
Total Bill on Non-RPP Avg. Price			**$ 0.99**			**$ 3.17**	**$ 2.18**	**220.20%**
HST	13%		$ 0.13	13%		$ 0.41	$ 0.28	220.20%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Non-RPP Avg. Price			**$ 1.12**			**$ 3.58**	**$ 2.46**	**220.20%**
Total Bill on Average IESO Wholesale Market Price			**$ 0.99**			**$ 3.17**	**$ 2.18**	**220.20%**
HST	13%		$ 0.13	13%		$ 0.41	$ 0.28	220.20%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 1.12**			**$ 3.58**	**$ 2.46**	**220.20%**

Customer Class:	STANDBY POWER SERVICE CLASSIFICATION	
RPP / Non-RPP:	0	
Consumption	-	**kWh**
Demand	-	**kW**
Current Loss Factor	1.0481	
Proposed/Approved Loss Factor	1.0462	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	$ -	0	$ -	$ -	0	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	0	$ -	$ -	0	$ -	$ -	
Sub-Total A (excluding pass through)			**$ -**			$ -	**$ -**	
Line Losses on Cost of Power	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
CBR Class B Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
GA Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
Low Voltage Service Charge	$ -	-	$ -		-	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		-	$ -	$ -	-	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ -**			$ -	**$ -**	
RTSR - Network	$ -	-	$ -	$ -	-	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	-	$ -	$ -	-	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ -**			$ -	**$ -**	
Wholesale Market Service Charge (WMSC)	$ -	-	$ -	$ -	-	$ -	$ -	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	-	$ -	$ -	-	$ -	$ -	
Standard Supply Service Charge	$ -	1	$ -	$ 0.25	1	$ 0.25	$ 0.25	
TOU - Off Peak	$ 0.0740	-	$ -	$ 0.0740	-	$ -	$ -	
TOU - Mid Peak	$ 0.1020	-	$ -	$ 0.1020	-	$ -	$ -	
TOU - On Peak	$ 0.1510	-	$ -	$ 0.1510	-	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ -**			**$ 0.25**	**$ 0.25**	
HST	13%		$ -	13%		$ 0.03	$ 0.03	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -	$ -	
Total Bill on TOU			**$ -**			**$ 0.28**	**$ 0.28**	
Total Bill on Non-RPP Avg. Price			**$ -**			**$ 0.25**	**$ 0.25**	
HST	13%		$ -	13%		$ 0.03	$ 0.03	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Non-RPP Avg. Price			**$ -**			**$ 0.28**	**$ 0.28**	
Total Bill on Average IESO Wholesale Market Price			**$ -**			**$ 0.25**	**$ 0.25**	
HST	13%		$ -	13%		$ 0.03	$ 0.03	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ -**			**$ 0.28**	**$ 0.28**	

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	318 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 33.72	1	$ 33.72	$ 38.35	1	$ 38.35	$ 4.63	13.73%
Distribution Volumetric Rate	$ -	318	$ -	$ -	318	$ -	$ -	
Fixed Rate Riders	$ 1.82	1	$ 1.82	$ 0.89	1	$ 0.89	$ (0.93)	-51.10%
Volumetric Rate Riders	$ -	318	$ -	$ 0.0002	318	$ 0.06	$ 0.06	
Sub-Total A (excluding pass through)			**$ 35.54**			**$ 39.30**	**$ 3.76**	**10.59%**
Line Losses on Cost of Power	$ 0.0926	15	$ 1.42	$ 0.0926	15	$ 1.36	$ (0.06)	-3.95%
Total Deferral/Variance Account Rate Riders	$ 0.0003	318	$ 0.10	$ 0.0002	318	$ 0.06	$ (0.03)	-33.33%
CBR Class B Rate Riders	$ (0.0001)	318	$ (0.03)	$ -	318	$ -	$ 0.03	-100.00%
GA Rate Riders	$ -	318	$ -	$ -	318	$ -	$ -	
Low Voltage Service Charge	$ -	318	$ -		318	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		318	$ -	$ (0.0002)	318	$ (0.06)	$ (0.06)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 37.44**			**$ 41.08**	**$ 3.64**	**9.73%**
RTSR - Network	$ 0.0086	333	$ 2.87	$ 0.0092	333	$ 3.06	$ 0.19	6.78%
RTSR - Connection and/or Line and Transformation Connection	$ -	333	$ -	$ -	333	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 40.31**			**$ 44.15**	**$ 3.84**	**9.52%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	333	$ 1.13	$ 0.0045	333	$ 1.50	$ 0.36	32.11%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	333	$ 0.23	$ 0.0007	333	$ 0.23	$ (0.00)	-0.18%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	207	$ 15.30	$ 0.0740	207	$ 15.30	$ -	0.00%
TOU - Mid Peak	$ 0.1020	54	$ 5.51	$ 0.1020	54	$ 5.51	$ -	0.00%
TOU - On Peak	$ 0.1510	57	$ 8.64	$ 0.1510	57	$ 8.64	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 71.38**			**$ 75.58**	**$ 4.20**	**5.89%**
HST	13%		$ 9.28	13%		$ 9.83	$ 0.55	5.89%
Ontario Electricity Rebate	17.0%		$ (12.13)	17.0%		$ (12.85)	$ (0.71)	
Total Bill on TOU			**$ 68.52**			**$ 72.56**	**$ 4.03**	**5.89%**

In the manager's summary, discuss the reas

5.4% VVO Model

Ontario Energy Board

Tariff Schedule and Bill Impacts Model

(2023 Cost of Service Filers)

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2017 of $0.1036/kWh (IESO's Monthly Market Report for May 2017, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	2,000		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0481	1.0462	57,220	145	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	3,600		CONSUMPTION	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kw	RPP	1.0481	1.0462	50	1	DEMAND	
STREET LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Retailer)	1.0481	1.0462	199,852	566	DEMAND	8,037
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION			1.0481	1.0462				
STANDBY POWER SERVICE CLASSIFICATION			1.0481	1.0462				
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0481	1.0462	318		CONSUMPTION	
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 4.00	11.3%	$ 3.81	9.7%	$ 3.88	8.4%	$ (0.10)	-0.1%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ 2.58	3.2%	$ 1.78	2.0%	$ 2.04	1.9%	$ (8.68)	-2.8%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 94.92	7.7%	$ (120.59)	-8.5%	$ (115.32)	-6.1%	$ (499.58)	-5.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ 9.38	5.5%	$ 7.95	4.3%	$ 8.41	3.9%	$ (10.83)	-1.9%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	$ 4.62	11.1%	$ 4.59	10.9%	$ 4.75	10.7%	$ 4.56	9.1%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$ 2,874.78	15.8%	$ 2,125.96	11.3%	$ 2,221.16	11.0%	$ 1,129.43	2.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION -									
STANDBY POWER SERVICE CLASSIFICATION -									
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	**750 kWh**
Demand	**- kW**
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0462**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 33.72	1	$ 33.72	$ 38.35	1	$ 38.35	$ 4.63	13.73%
Distribution Volumetric Rate	$ -	750	$ -	$ -	710	$ -	$ -	
Fixed Rate Riders	$ 1.82	1	$ 1.82	$ 1.05	1	$ 1.05	$ (0.77)	-42.31%
Volumetric Rate Riders	$ -	750	$ -	$ 0.0002	710	$ 0.14	$ 0.14	
Sub-Total A (excluding pass through)			**$ 35.54**			**$ 39.54**	**$ 4.00**	**11.26%**
Line Losses on Cost of Power	$ 0.0926	36	$ 3.34	$ 0.0926	35	$ 3.21	$ (0.13)	-3.95%
Total Deferral/Variance Account Rate Riders	$ 0.0003	750	$ 0.23	$ 0.0002	710	$ 0.14	$ (0.08)	-36.93%
CBR Class B Rate Riders	$ (0.0001)	750	$ (0.08)	$ (0.0001)	710	$ (0.07)	$ 0.00	-5.40%
GA Rate Riders	$ -	750	$ -	$ -	710	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		710	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	750	$ (0.30)	$ (0.0004)	710	$ (0.28)	$ 0.02	-5.40%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 39.15**			**$ 42.96**	**$ 3.81**	**9.72%**
RTSR - Network	$ 0.0086	786	$ 6.76	$ 0.0092	742	$ 6.83	$ 0.07	1.02%
RTSR - Connection and/or Line and Transformation Connection	$ -	786	$ -	$ -	742	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 45.91**			**$ 49.79**	**$ 3.88**	**8.44%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	786	$ 3.54	$ 0.0045	742	$ 3.34	$ (0.20)	-5.57%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	786	$ 0.55	$ 0.0007	742	$ 0.52	$ (0.03)	-5.57%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	488	$ 36.08	$ 0.0740	461	$ 34.13	$ (1.95)	-5.40%
TOU - Mid Peak	$ 0.1020	128	$ 13.01	$ 0.1020	121	$ 12.30	$ (0.70)	-5.40%
TOU - On Peak	$ 0.1510	135	$ 20.39	$ 0.1510	128	$ 19.28	$ (1.10)	-5.40%
Total Bill on TOU (before Taxes)			**$ 119.71**			**$ 119.61**	**$ (0.10)**	**-0.09%**
HST	13%		$ 15.56	13%		$ 15.55	$ (0.01)	-0.09%
Ontario Electricity Rebate	11.7%		$ (14.01)	11.7%		$ (13.99)	$ 0.01	
Total Bill on TOU			**$ 121.27**			**$ 121.17**	**$ (0.10)**	**-0.09%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 22.32	1	$ 22.32	$ 22.32	1	$ 22.32	$ -	0.00%
Distribution Volumetric Rate	$ 0.0268	2000	$ 53.60	$ 0.0319	1892	$ 60.35	$ 6.75	12.60%
Fixed Rate Riders	$ 1.21	1	$ 1.21	$ 2.48	1	$ 2.48	$ 1.27	104.96%
Volumetric Rate Riders	$ 0.0014	2000	$ 2.80	$ (0.0014)	1892	$ (2.65)	$ (5.45)	-194.60%
Sub-Total A (excluding pass through)			**$ 79.93**			**$ 82.51**	**$ 2.58**	**3.22%**
Line Losses on Cost of Power	$ 0.0926	96	$ 8.91	$ 0.0926	87	$ 8.10	$ (0.81)	-9.14%
Total Deferral/Variance Account Rate Riders	$ 0.0003	2,000	$ 0.60	$ 0.0003	1,892	$ 0.57	$ (0.03)	-5.40%
CBR Class B Rate Riders	$ (0.0001)	2,000	$ (0.20)	$ (0.0001)	1,892	$ (0.19)	$ 0.01	-5.40%
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	2,000	$ (0.80)	$ (0.0004)	1,892	$ (0.76)	$ 0.04	-5.40%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 88.86**			**$ 90.64**	**$ 1.78**	**2.01%**
RTSR - Network	$ 0.0080	2,096	$ 16.77	$ 0.0086	1,979	$ 17.02	$ 0.25	1.51%
RTSR - Connection and/or Line and Transformation Connection	$ -	2,096	$ -	$ -	1,979	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 105.63**			**$ 107.67**	**$ 2.04**	**1.93%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,096	$ 9.43	$ 0.0045	1,979	$ 8.91	$ (0.53)	-5.57%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	2,096	$ 1.47	$ 0.0007	1,979	$ 1.39	$ (0.08)	-5.57%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	1,300	$ 96.20	$ 0.0740	1,230	$ 91.01	$ (5.19)	-5.40%
TOU - Mid Peak	$ 0.1020	340	$ 34.68	$ 0.1020	322	$ 32.81	$ (1.87)	-5.40%
TOU - On Peak	$ 0.1510	360	$ 54.36	$ 0.1510	341	$ 51.42	$ (2.94)	-5.40%
Total Bill on TOU (before Taxes)			**$ 302.02**			**$ 293.45**	**$ (8.57)**	**-2.84%**
HST	13%		$ 39.26	13%		$ 38.15	$ (1.11)	-2.84%
Ontario Electricity Rebate	11.7%		$ (35.34)	11.7%		$ (34.33)	$ 1.00	
Total Bill on TOU			**$ 305.95**			**$ 297.26**	**$ (8.68)**	**-2.84%**

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	**1.0481**
Proposed/Approved Loss Factor	**1.0462**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 123.27	1	$ 123.27	$ 123.27	1	$ 123.27	$ -	0.00%
Distribution Volumetric Rate	$ 7.2479	145	$ 1,050.95	$ 8.3565	137	$ 1,146.26	$ 95.32	9.07%
Fixed Rate Riders	$ 6.65	1	$ 6.65	$ 24.75	1	$ 24.75	$ 18.10	272.18%
Volumetric Rate Riders	$ 0.3914	145	$ 56.75	$ 0.2789	137	$ 38.26	$ (18.50)	-32.59%
Sub-Total A (excluding pass through)			**$ 1,237.62**			**$ 1,332.54**	**$ 94.92**	**7.67%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.1286	145	$ 18.65	$ 0.1195	137	$ 16.39	$ (2.26)	-12.09%
CBR Class B Rate Riders	$ (0.0234)	145	$ (3.39)	$ (0.0540)	137	$ (7.41)	$ (4.01)	118.31%
GA Rate Riders	$ 0.0033	57,220	$ 188.83	$ (0.0004)	54,130	$ (21.65)	$ (210.48)	-111.47%
Low Voltage Service Charge	$ -	145	$ -		145	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	57,220	$ (22.89)	$ (0.0004)	54,130	$ (21.65)	$ 1.24	-5.40%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,418.81**			**$ 1,298.22**	**$ (120.59)**	**-8.50%**
RTSR - Network	$ 3.2337	145	$ 468.89	$ 3.4567	137	$ 474.16	$ 5.27	1.12%
RTSR - Connection and/or Line and Transformation Connection	$ -	145	$ -	$ -	137	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,887.70**			**$ 1,772.37**	**$ (115.32)**	**-6.11%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	59,972	$ 269.88	$ 0.0045	56,631	$ 254.84	$ (15.04)	-5.57%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	59,972	$ 41.98	$ 0.0007	56,631	$ 39.64	$ (2.34)	-5.57%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.0926	59,972	$ 5,553.43	$ 0.0926	56,631	$ 5,244.02	$ (309.41)	-5.57%
Total Bill on Average IESO Wholesale Market Price			**$ 7,753.24**			**$ 7,311.13**	**$ (442.11)**	**-5.70%**
HST	13%		$ 1,007.92	13%		$ 950.45	$ (57.47)	-5.70%
Ontario Electricity Rebate	11.7%		$ -	11.7%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 8,761.16**			**$ 8,261.58**	**$ (499.58)**	**-5.70%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	**3,600**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0481**	
Proposed/Approved Loss Factor	**1.0462**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 13.67**	1	$ 13.67	**$ 13.67**	**1**	**$ 13.67**	$ -	0.00%
Distribution Volumetric Rate	**$ 0.0412**	3600	$ 148.32	**$ 0.0476**	**3406**	**$ 162.11**	$ 13.79	9.30%
Fixed Rate Riders	**$ 0.74**	1	$ 0.74	**$ 2.91**	**1**	**$ 2.91**	$ 2.17	293.24%
Volumetric Rate Riders	**$ 0.0023**	3600	$ 8.28	**$ 0.0005**	**3406**	**$ 1.70**	$ (6.58)	-79.43%
Sub-Total A (excluding pass through)			**$ 171.01**			**$ 180.39**	**$ 9.38**	**5.48%**
Line Losses on Cost of Power	**$ 0.0926**	173	$ 16.04	**$ 0.0926**	**157**	**$ 14.57**	$ (1.47)	-9.14%
Total Deferral/Variance Account Rate Riders	**$ 0.0003**	3,600	$ 1.08	**$ 0.0003**	**3406**	**$ 1.02**	$ (0.06)	-5.40%
CBR Class B Rate Riders	**$ (0.0001)**	3,600	$ (0.36)	**$ (0.0001)**	**3406**	**$ (0.34)**	$ 0.02	-5.40%
GA Rate Riders	**$ -**	3,600	$ -	**$ -**	**3406**	**$ -**	$ -	
Low Voltage Service Charge	**$ -**	3,600	$ -		**3406**	**$ -**	$ -	
Smart Meter Entity Charge (if applicable)	**$ -**	1	$ -	**$ -**	**1**	**$ -**	$ -	
Additional Fixed Rate Riders	**$ -**	1	$ -	**$ -**	**1**	**$ -**	$ -	
Additional Volumetric Rate Riders	**$ (0.0004)**	3,600	$ (1.44)	**$ (0.0004)**	**3406**	**$ (1.36)**	$ 0.08	-5.40%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 186.33**			**$ 194.28**	**$ 7.95**	**4.27%**
RTSR - Network	**$ 0.0080**	3,773	$ 30.19	**$ 0.0086**	**3,563**	**$ 30.64**	$ 0.46	1.51%
RTSR - Connection and/or Line and Transformation Connection	**$ -**	3,773	$ -	**$ -**	**3,563**	**$ -**	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 216.51**			**$ 224.92**	**$ 8.41**	**3.88%**
Wholesale Market Service Charge (WMSC)	**$ 0.0045**	3,773	$ 16.98	**$ 0.0045**	**3,563**	**$ 16.03**	$ (0.95)	-5.57%
Rural and Remote Rate Protection (RRRP)	**$ 0.0007**	3,773	$ 2.64	**$ 0.0007**	**3,563**	**$ 2.49**	$ (0.15)	-5.57%
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	**$ 0.25**	**1**	**$ 0.25**	$ -	0.00%
TOU - Off Peak	**$ 0.0740**	2,340	$ 173.16	**$ 0.0740**	**2,214**	**$ 163.81**	$ (9.35)	-5.40%
TOU - Mid Peak	**$ 0.1020**	612	$ 62.42	**$ 0.1020**	**579**	**$ 59.05**	$ (3.37)	-5.40%
TOU - On Peak	**$ 0.1510**	648	$ 97.85	**$ 0.1510**	**613**	**$ 92.56**	$ (5.28)	-5.40%
Total Bill on TOU (before Taxes)			**$ 569.82**			**$ 559.13**	**$ (10.69)**	**-1.88%**
HST	13%		$ 74.08	13%		$ 72.69	$ (1.39)	-1.88%
Ontario Electricity Rebate	11.7%		$ (66.67)	11.7%		$ (65.42)	$ 1.25	
Total Bill on TOU			**$ 577.22**			**$ 566.39**	**$ (10.83)**	**-1.88%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	50 kWh
Demand	1 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 3.83	1	$ 3.83	$ 4.35	1	$ 4.35	$ 0.52	13.58%
Distribution Volumetric Rate	$ 35.7037	1	$ 35.70	$ 40.6108	1	$ 40.61	$ 4.91	13.74%
Fixed Rate Riders	$ 0.20	1	$ 0.20	$ 0.39	1	$ 0.39	$ 0.19	95.00%
Volumetric Rate Riders	$ 1.9278	1	$ 1.93	$ 0.9344	1	$ 0.93	$ (0.99)	-51.53%
Sub-Total A (excluding pass through)			**$ 41.66**			**$ 46.29**	**$ 4.62**	**11.10%**
Line Losses on Cost of Power	$ 0.0926	2	$ 0.22	$ 0.0926	2	$ 0.21	$ (0.01)	-3.95%
Total Deferral/Variance Account Rate Riders	$ 0.1057	1	$ 0.11	$ 0.1012	1	$ 0.10	$ (0.00)	-4.26%
CBR Class B Rate Riders	$ (0.0201)	1	$ (0.02)	$ (0.0462)	1	$ (0.05)	$ (0.03)	129.85%
GA Rate Riders	$ -	50	$ -	$ -	47	$ -	$ -	
Low Voltage Service Charge	$ -	1	$ -		1	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	50	$ (0.02)	$ (0.0004)	47	$ (0.02)	$ 0.00	-5.40%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 41.95**			**$ 46.54**	**$ 4.59**	**10.93%**
RTSR - Network	$ 2.4511	1	$ 2.45	$ 2.6202	1	$ 2.62	$ 0.17	6.90%
RTSR - Connection and/or Line and Transformation Connection	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 44.40**			**$ 49.16**	**$ 4.75**	**10.71%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	52	$ 0.24	$ 0.0045	52	$ 0.24	$ (0.00)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	52	$ 0.04	$ 0.0007	52	$ 0.04	$ (0.00)	-0.18%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	33	$ 2.41	$ 0.0740	31	$ 2.28	$ (0.13)	-5.40%
TOU - Mid Peak	$ 0.1020	9	$ 0.87	$ 0.1020	8	$ 0.82	$ (0.05)	-5.40%
TOU - On Peak	$ 0.1510	9	$ 1.36	$ 0.1510	9	$ 1.29	$ (0.07)	-5.40%
Total Bill on TOU (before Taxes)			**$ 49.55**			**$ 54.06**	**$ 4.50**	**9.09%**
HST	13%		$ 6.44	13%		$ 7.03	$ 0.59	9.09%
Ontario Electricity Rebate	11.7%		$ (5.80)	11.7%		$ (6.32)	$ (0.53)	
Total Bill on TOU			**$ 50.20**			**$ 54.76**	**$ 4.56**	**9.09%**

In the manager's summary, discuss the reas

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	199,852 kWh
Demand	566 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 1.47	8037	$ 11,814.39	$ 1.67	8037	$ 13,421.79	$ 1,607.40	13.61%
Distribution Volumetric Rate	$ 9.6161	566	$ 5,442.71	$ 10.9378	566	$ 6,190.79	$ 748.08	13.74%
Fixed Rate Riders	$ 0.08	8037	$ 642.96	$ 0.13	8037	$ 1,044.81	$ 401.85	62.50%
Volumetric Rate Riders	$ 0.5192	566	$ 293.87	$ 0.7267	566	$ 411.31	$ 117.45	39.97%
Sub-Total A (excluding pass through)			**$ 18,193.93**			**$ 21,068.71**	**$ 2,874.78**	**15.80%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.1061	566	$ 60.05	$ 0.1010	566	$ 57.17	$ (2.89)	-4.81%
CBR Class B Rate Riders	$ (0.0194)	566	$ (10.98)	$ (0.0461)	566	$ (26.09)	$ (15.11)	137.63%
GA Rate Riders	$ 0.0033	199,852	$ 659.51	$ (0.0004)	189,060	$ (75.62)	$ (735.14)	-111.47%
Low Voltage Service Charge	$ -	566	$ -		566	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	199,852	$ (79.94)	$ (0.0004)	189,060	$ (75.62)	$ 4.32	-5.40%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 18,822.57**			**$ 20,948.53**	**$ 2,125.96**	**11.29%**
RTSR - Network	$ 2.4391	566	$ 1,380.53	$ 2.6073	566	$ 1,475.73	$ 95.20	6.90%
RTSR - Connection and/or Line and Transformation Connection	$ -	566	$ -	$ -	566	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 20,203.10**			**$ 22,424.26**	**$ 2,221.16**	**10.99%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	209,465	$ 942.59	$ 0.0045	198,154	$ 891.69	$ (50.90)	-5.40%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	209,465	$ 146.63	$ 0.0007	198,154	$ 138.71	$ (7.92)	-5.40%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.0926	209,465	$ 19,396.45	$ 0.0926	198,154	$ 18,349.04	$ (1,047.41)	-5.40%
Total Bill on Non-RPP Avg. Price			**$ 40,688.77**			**$ 41,803.70**	**$ 1,114.93**	**2.74%**
HST	13%		$ 5,289.54	13%		$ 5,434.48	$ 144.94	2.74%
Ontario Electricity Rebate	11.7%		$ (4,760.59)	11.7%		$ (4,891.03)		
Total Bill on Non-RPP Avg. Price			**$ 41,217.72**			**$ 42,347.15**	**$ 1,129.43**	**2.74%**

In the manager's summary, discuss the reas

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	0
Consumption	- kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 13.67		$ -	$ 13.67	0	$ -	$ -	
Distribution Volumetric Rate	$ 0.0412	0	$ -	$ 0.0476	0	$ -	$ -	
Fixed Rate Riders	$ 0.74	1	$ 0.74	$ 2.92	1	$ 2.92	$ 2.18	294.59%
Volumetric Rate Riders	$ 0.0023	0	$ -	$ 0.0002	0	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 0.74**			**$ 2.92**	**$ 2.18**	**294.59%**
Line Losses on Cost of Power	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.0003	-	$ -	$ 0.0003	-	$ -	$ -	
CBR Class B Rate Riders	$ (0.0001)	-	$ -	$ -	-	$ -	$ -	
GA Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
Low Voltage Service Charge	$ -	-	$ -		-	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		-	$ -	$ (0.0002)	-	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 0.74**			**$ 2.92**	**$ 2.18**	**294.59%**
RTSR - Network	$ 0.0080	-	$ -	$ 0.0086	-	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	-	$ -	$ -	-	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 0.74**			**$ 2.92**	**$ 2.18**	**294.59%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	-	$ -	$ 0.0045	-	$ -	$ -	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	-	$ -	$ 0.0007	-	$ -	$ -	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	-	$ -	$ 0.0740	-	$ -	$ -	
TOU - Mid Peak	$ 0.1020	-	$ -	$ 0.1020	-	$ -	$ -	
TOU - On Peak	$ 0.1510	-	$ -	$ 0.1510	-	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 0.99**			**$ 3.17**	**$ 2.18**	**220.20%**
HST	13%		$ 0.13	13%		$ 0.41	$ 0.28	220.20%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -	$ -	
Total Bill on TOU			**$ 1.12**			**$ 3.58**	**$ 2.46**	**220.20%**
Total Bill on Non-RPP Avg. Price			**$ 0.99**			**$ 3.17**	**$ 2.18**	**220.20%**
HST	13%		$ 0.13	13%		$ 0.41	$ 0.28	220.20%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Non-RPP Avg. Price			**$ 1.12**			**$ 3.58**	**$ 2.46**	**220.20%**
Total Bill on Average IESO Wholesale Market Price			**$ 0.99**			**$ 3.17**	**$ 2.18**	**220.20%**
HST	13%		$ 0.13	13%		$ 0.41	$ 0.28	220.20%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 1.12**			**$ 3.58**	**$ 2.46**	**220.20%**

Customer Class:	STANDBY POWER SERVICE CLASSIFICATION
RPP / Non-RPP:	0
Consumption	- kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	$ -	0	$ -	$ -	0	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	0	$ -	$ -	0	$ -	$ -	
Sub-Total A (excluding pass through)			**$ -**			$ -	**$ -**	
Line Losses on Cost of Power	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
CBR Class B Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
GA Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
Low Voltage Service Charge	$ -	-	$ -		-	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		-	$ -	$ -	-	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ -**			$ -	**$ -**	
RTSR - Network	$ -	-	$ -	$ -	-	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	-	$ -	$ -	-	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ -**			$ -	**$ -**	
Wholesale Market Service Charge (WMSC)	$ -	-	$ -	$ -	-	$ -	$ -	
Rural and Remote Rate Protection (RRRP)	$ 0.0007	-	$ -	$ -	-	$ -	$ -	
Standard Supply Service Charge	$ -	1	$ -	$ 0.25	1	$ 0.25	$ 0.25	
TOU - Off Peak	$ 0.0740	-	$ -	$ 0.0740	-	$ -	$ -	
TOU - Mid Peak	$ 0.1020	-	$ -	$ 0.1020	-	$ -	$ -	
TOU - On Peak	$ 0.1510	-	$ -	$ 0.1510	-	$ -	$ -	
Non-RPP Retailer Avg. Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Average IESO Wholesale Market Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ -**			**$ 0.25**	**$ 0.25**	
HST	13%		$ -	13%		$ 0.03	$ 0.03	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -	$ -	
Total Bill on TOU			**$ -**			**$ 0.28**	**$ 0.28**	
Total Bill on Non-RPP Avg. Price			**$ -**			**$ 0.25**	**$ 0.25**	
HST	13%		$ -	13%		$ 0.03	$ 0.03	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Non-RPP Avg. Price			**$ -**			**$ 0.28**	**$ 0.28**	
Total Bill on Average IESO Wholesale Market Price			**$ -**			**$ 0.25**	**$ 0.25**	
HST	13%		$ -	13%		$ 0.03	$ 0.03	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ -**			**$ 0.28**	**$ 0.28**	

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	318 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 33.72	1	$ 33.72	$ 38.35	1	$ 38.35	$ 4.63	13.73%
Distribution Volumetric Rate	$ -	318	$ -	$ -	318	$ -	$ -	
Fixed Rate Riders	$ 1.82	1	$ 1.82	$ 0.89	1	$ 0.89	$ (0.93)	-51.10%
Volumetric Rate Riders	$ -	318	$ -	$ 0.0002	318	$ 0.06	$ 0.06	
Sub-Total A (excluding pass through)			**$ 35.54**			**$ 39.30**	**$ 3.76**	**10.59%**
Line Losses on Cost of Power	$ 0.0926	15	$ 1.42	$ 0.0926	15	$ 1.36	$ (0.06)	-3.95%
Total Deferral/Variance Account Rate Riders	$ 0.0003	318	$ 0.10	$ 0.0002	318	$ 0.06	$ (0.03)	-33.33%
CBR Class B Rate Riders	$ (0.0001)	318	$ (0.03)	$ -	318	$ -	$ 0.03	-100.00%
GA Rate Riders	$ -	318	$ -	$ -	318	$ -	$ -	
Low Voltage Service Charge	$ -	318	$ -		318	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		318	$ -	$ (0.0002)	318	$ (0.06)	$ (0.06)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 37.44**			**$ 41.08**	**$ 3.64**	**9.73%**
RTSR - Network	$ 0.0086	333	$ 2.87	$ 0.0092	333	$ 3.06	$ 0.19	6.78%
RTSR - Connection and/or Line and Transformation Connection	$ -	333	$ -	$ -	333	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 40.31**			**$ 44.15**	**$ 3.84**	**9.52%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	333	$ 1.13	$ 0.0045	333	$ 1.50	$ 0.36	32.11%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	333	$ 0.23	$ 0.0007	333	$ 0.23	$ (0.00)	-0.18%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	207	$ 15.30	$ 0.0740	207	$ 15.30	$ -	0.00%
TOU - Mid Peak	$ 0.1020	54	$ 5.51	$ 0.1020	54	$ 5.51	$ -	0.00%
TOU - On Peak	$ 0.1510	57	$ 8.64	$ 0.1510	57	$ 8.64	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 71.38**			**$ 75.58**	**$ 4.20**	**5.89%**
HST	13%		$ 9.28	13%		$ 9.83	$ 0.55	5.89%
Ontario Electricity Rebate	17.0%		$ (12.13)	17.0%		$ (12.85)	$ (0.71)	
Total Bill on TOU			**$ 68.52**			**$ 72.56**	**$ 4.03**	**5.89%**

In the manager's summary, discuss the reas

Appendix E – Draft Tariff of Rates and Charges

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	38.35
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	0.54
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$	(0.65)
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$	(0.98)
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	2.14
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kWh	0.0002
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2024	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0092

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	22.32
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	1.23
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	1.25
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate	$/kWh	0.0319
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kWh	0.0018
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kWh	0.0003
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$/kWh	(0.0010)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2024	$/kWh	(0.0013)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kWh	(0.0009)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

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EB-2022-0059

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. Class A and Class B consumers are defined on accordance with O. Reg. 429/04. 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.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	123.27
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	17.87
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	6.88
Distribution Volumetric Rate	$/kW	8.3565
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kW	0.4601
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kW	0.1195
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$/kW	(0.2240)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0540)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2024	$/kW	0.4587
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kW	(0.4159)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2023
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EB-2022-0059

Retail Transmission Rate - Network Service Rate	$/kW	3.4567
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	4.3474

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

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EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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.

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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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	13.67
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	2.15
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	0.76
Distribution Volumetric Rate	$/kWh	0.0476
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kWh	0.0027
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kWh	0.0003
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$/kWh	(0.0013)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kWh	(0.0009)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

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EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.35
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	0.15
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	0.24
Distribution Volumetric Rate	$/kW	40.6108
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kW	2.2678
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kW	0.1012
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$/kW	(1.7931)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0462)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kW	0.4597
Retail Transmission Rate - Network Service Rate	$/kW	2.6202

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

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EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.67
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	0.04
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	0.09
Distribution Volumetric Rate	$/kW	10.9378
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kW	0.6108
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kW	0.1010
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$/kW	(0.8559)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0461)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kW	0.9718
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kW	2.6073

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment - effective until	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

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EB-2022-0059

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.

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.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

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.

No 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.

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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 (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection charge - at meter - during regular hours	$	65.00
Reconnection charge - at meter - after hours	$	185.00

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
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EB-2022-0059

Reconnection charge - at pole - during regular hours	$	185.00
Reconnection charge - at pole - after hours	$	415.00

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		
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	36.05
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)

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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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	$	111.66
Monthly fixed charge, per retailer	$	44.67
Monthly variable charge, per customer, per retailer	$/cust.	1.11
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.66
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.66)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.56
Processing fee, per request, applied to the requesting party	$	1.11
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)	$	4.47
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.23

LOSS FACTORS

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

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EB-2022-0059

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	1.0462
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0357

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

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EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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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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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	38.35
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	0.54
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$	(0.65)
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$	(0.98)
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	2.14
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kWh	0.0002
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2024	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0092

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	22.32
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	1.23
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	1.25
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate	$/kWh	0.0319
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kWh	0.0018
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kWh	0.0003
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$/kWh	(0.0010)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2024	$/kWh	(0.0013)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kWh	(0.0009)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004

Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2023
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EB-2022-0059

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. Class A and Class B consumers are defined on accordance with O. Reg. 429/04. 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.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	123.27
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	17.87
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	6.88
Distribution Volumetric Rate	$/kW	8.3565
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kW	0.4601
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kW	0.1195
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$/kW	(0.2240)

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
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EB-2022-0059

Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0540)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2024	$/kW	0.4587
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kW	(0.4159)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kW	3.4567
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	4.3474

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

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EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	13.67
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	2.15
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	0.76
Distribution Volumetric Rate	$/kWh	0.0476
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kWh	0.0027
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kWh	0.0003
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$/kWh	(0.0013)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kWh	(0.0009)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

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EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.35
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	0.15
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	0.24
Distribution Volumetric Rate	$/kW	40.6108
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kW	2.2678
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kW	0.1012
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$/kW	(1.7931)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0462)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kW	0.4597
Retail Transmission Rate - Network Service Rate	$/kW	2.6202

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2023
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EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.67
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	0.04
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	0.09
Distribution Volumetric Rate	$/kW	10.9378
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kW	0.6108
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kW	0.1010
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2024	$/kW	(0.8559)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0461)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kW	0.9718
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kW	2.6073

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment - effective until	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004

Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2023
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EB-2022-0059

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.

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.

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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

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.

No 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.

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 Global Adjustment and the HST.

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		
(effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection charge - at meter - during regular hours	$	65.00
Reconnection charge - at meter - after hours	$	185.00
Reconnection charge - at pole - during regular hours	$	185.00
Reconnection charge - at pole - after hours	$	415.00

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		
Specific charge for access to the power poles - $/pole/year		
(with the exception of wireless attachments)	$	36.05
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)

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.

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 Global Adjustment and the HST.

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	$	111.66
Monthly fixed charge, per retailer	$	44.67
Monthly variable charge, per customer, per retailer	$/cust.	1.11
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.66
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.66)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.56
Processing fee, per request, applied to the requesting party	$	1.11
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)	$	4.47
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.23

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	1.0462
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0357

Appendix F – Pre-Settlement Clarification Questions

Appendix G – 2023 COS Accounting Order

Account 1508 - Other Regulatory Assets, Sub-account Incremental VVO Savings or Costs

PUC Distribution Inc.

2023 Cost of Service Application – Sault Smart Grid Project Voltage / VAR Optimization Linkage to Return on Equity

EB-2022-0059

Accounting Order

Account 1508 Other Regulatory Assets

Sub-accounts Incremental VVO Savings or Costs

March 10, 2023

PUC Distribution Inc. - 2023 Cost of Service Application – Sault Smart Grid Project VVO Linkage to ROE

Accounting Order

Account 1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings

As part of the Ontario Energy Board's ("OEB") decision on the Sault Smart Grid ("SSG") project (EB-2018-0219/EB-2020-0249), PUC Distribution Inc. ("PUC") was required to file all available information on the proposed SSG performance metrics that it intends to track, along with proposed targets, in its next rebasing application. The OEB required PUC to include an appropriate metric and targets to symmetrically link the Voltage / VAR Optimization ("VVO") performance of SSG to PUC's allowable Return on Equity ("ROE") for this Project. PUC proposed and the Parties agreed to do this through the use of Account 1508 – Other Regulatory Assets, Sub Account Incremental VVO Costs or Savings. The sub-account will record incremental VVO savings or costs to customers in a given year. The following describes the calculation of the VVO % savings to ROE linkage and includes the corresponding sample journal entries for the sharing of incremental savings or costs to customers.

This sub-account will have an effective date of May 1, 2023.

<u>VVO Link to ROE</u>

As identified in its SSG ICM Application, PUC's target is to achieve 2.70% VVO savings. If PUC achieves VVO savings that is above or below this target, it will symmetrically collect or refund or the percentage difference on its ROE for the SSG Project in that respective year using the following formula:

$$\text{Debit/Credit} = \frac{AVS - TVS}{TVS} \times SSGROE$$

Variables:

- AVS means the actual VVO energy savings achieved (expressed as a percentage of energy consumption) from the SSG project over a given calendar year.
- TVS means the targeted VVO savings from the SSG project, which shall be fixed at 2.70%.

- SSGROE means the return on equity component of revenue requirement of the SSG project in a calendar year as set out in Table 1 below.

Table 1: SSGROE Values Between 2023 and 2027

Year	Return on Base – Equity (SSGROE)
2023	$614,958
2024	$883,842
2025	$858,097
2026	$832,352
2027	$806,606

The ROE Revenue Requirement of the SSG project will be determined using the project reconciliation amounts that PUC is required to provide as part of its next rebasing application consistent with the SSG Project Recovery Mechanism. The cost of capital parameters used to calculate ROE shall be those that are used as part of the SSG Project Recovery Mechanism model filed with PUC's Settlement Proposal for its 2023 Cost of Service Rate application (EB-2022-0059). An example of the calculation is provided in Table 1 above. The ROE values in Table 1 are for illustrative purposes only. The ROE values used in the calculation will be based on the lower i) actual SSG Project capital costs and in-service dates, and ii) and the settled amount used to calculated the SSG Recovery Mechanism Rate Rider.

Table 2 VVO Over/Under Target Scenarios[1]

	Over VVO Target	Under VVO Target
ROE	$750,000	$750,000
VVO %Target	2.70%	2.70%
VVO %Result	3.00%	2.40%
delta	11.11%	-11.11%
Refund/Collection	$83,333	($83,333)

1 – These numbers are for illustration purposes only. The actual amount will vary given the VVO kWh savings and ROE amount from year to year.

The scenarios in Table 2 result in either a debit (collection) from customer or a credit (refund) to customers. A sample of corresponding journal entries is provided in Table 3 below.

Table 3 – Accounting Entries for VVO Over/Under Target Scenarios[1]

VVO Result 2.40%		
4080 Distribution Revenue	$83,333	
1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings		$83,333
to record the increase in savings to PUC customers		

VVO Result 3.00%		
1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings	$83,333	
4080 Distribution Revenue		$83,333
to record the reduction in savings to PUC Customers		

1 – These numbers are for illustration purposes only. The actual amount will vary given the VVO kWh savings and ROE amount from year to year.

Additionally, PUC will apply a symmetrical maximum upside (5.4% VVO kWh savings) and downside (0% VVO kWh savings) equal to the ROE of the SSG Project.

Disposition of the Account Balance

The Parties agree that at the next rebasing application where PUC shall bring forward the sub-account for disposition, the OEB panel hearing the matter will have discretion regarding how much, if any amount, should ultimately be recorded in the account and disposed to the benefit of either PUC or customers. The parties' agreement on this matter is based on the following expected treatment of the account:

- the maximum amount that can be credited or debited for any year shall not exceed the level of the symmetrical maximum upside (5.4% VVO kWh savings) and downside (0% VVO kWh savings) for the calculated ROE for the SSG Project in accordance with the formula above. Any calculated amounts are solely related to VVO consumptions savings and all other factors (e.g., distribution automation) are excluded from this account;
- the principle of symmetrical risk/reward of this account around a targeted VVO savings of 2.70% shall be maintained to the maximum extent possible; and
- the OEB panel deciding the disposition of the account will be guided by the results of the report(s) set out in Issue 5.4 of the Settlement Proposal, and any information that arises from review of those reports.

As referenced by PUC in Clarification Question CCC-55, substantial completion of the project requires optimization and testing by Black and Veatch: (a) on a station by station basis to finalize voltage reduction settings and control systems; and (b) on full system wide basis to confirm coordinated station performance, which includes items such as integrated measurement, verification and reporting. As set out in the response to Staff-29, the testing and optimization phase of the SSG Project PUC anticipates to be in a position to start measuring VVO savings at the time of Substantial Completion. Substantial Completion is currently expected to occur November 1, 2023. On that basis, Parties have not agreed how to apply the VVO Link to ROE formula for the 2023 year (or if necessary, into 2024).

The Parties do agree that the OEB at the time of disposition of the account will address, what if any, amount for 2023 should be disposed to the benefit of ratepayers or the utility. At that time, and subject to the operation of this account, some Parties may take the position that PUC should receive no ROE for the period in which the project is not substantially complete or for any period in which the project fails to operate as expected after it becomes substantially complete.

The Parties expect that the OEB will take into account the Parties' agreement on the above noted treatment of the account when the OEB considers disposition of the account.

The continuation or discontinuation of this account shall be addressed at the time of PUC's 2028 rebasing application.

1) Account 1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings

This account shall be used to record incremental VVO costs or savings to customers when the VVO percentage is above or below the targeted 2.70% VVO savings. The savings or costs have upper and lower maximums of 5.40% and 0% respectively equalling the ROE of the SSG Project for a given year as detailed above.

2) Account 1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings Carrying Charges

Carrying charges shall be recorded monthly in this sub-account, calculated using simple interest applied to the opening balances in the Incremental VVO Costs of Savings sub-account. The interest rate shall be at the OEB's prescribed rate. The following are sample journal entries is an example for carrying charges.

6035 – Other Interest Expense

1508 – Sub-account Incremental VVO Costs or Savings Carrying Charges

To record the carrying charges if there is a credit balance owing to customers at year end.

1508 – Sub-account Incremental VVO Costs or Savings Carrying Charges

4405 – Interest and Dividend Income

To record the carrying charges if there is a debit balance owing from customers at year end.

Appendix H – 2023 COS Accounting Order

Account 1508 - Other Regulatory Assets,

Sub-account SSG EPC Contract Liquidated Damages

PUC Distribution Inc.

2023 Cost of Service Application – Sault Smart Grid Project
Liquidated Damages

EB-2022-0059

Accounting Order

Account 1508 Other Regulatory Assets

Sub-account SSG EPC Contract Liquidated Damages

March 10, 2023

PUC Distribution Inc. - 2023 Cost of Service Application – Sault Smart Grid Project Liquidated Damages

Accounting Order
Account 1508 Other Regulatory Assets,
Sub-account SSG EPC Contract Liquidated Damages

As part of the Ontario Energy Board's ("OEB") decision on the Sault Smart Grid project (EB-2018-0219/EB-2020-0249) ("SSG"), the OEB found that in order to manage the risks associated with SSG and appropriately monitor its progress, the OEB approval was subject to the following condition:

> *"Any EPC Contract liquidated damages resulting from "performance" or "delay" shall be used to reduce the project capital cost and would be settled at the time of the next rebasing."*

No liquidated damages were calculated as of the time of the 2023 Cost of Service application. This sub-account is to record the revenue requirement impact of any liquidated damages received by PUC for the SSG Project, so that the reduction to the settled upon SSG revenue requirement resulting from liquidated damages is returned to ratepayers. This sub-account will have an effective date of May 1, 2023 and will record the revenue requirement impact of any liquidated damages received related to the SSG Project even if they were received or became due before the effective date.

1) Account 1508 Other Regulatory Assets, Sub-account SSG EPC Contract Liquidated Damages

This account shall be used to record the revenue requirement impact of any liquidated damages received.

2) Account 1508 Other Regulatory Assets, Sub-account SSG EPC Contract Liquidated Damages Carrying Charges

Carrying charges shall be recorded monthly in this sub-account, calculated using simple interest applied to the opening balances in the SSG EPC Contract Liquidated Damages sub-account. The interest rate shall be at the OEB's prescribed rate.

A sample of the journal entries associated with liquidated damages is presented below.

4080 - Distribution Revenue $XX

1508 – Sub-account SSG EPC Contract Liquidated Damages $XX

SSG EPC Contract Liquidated Damages
To record the revenue requirement impact from liquidated damages received.

The following are sample journal entries is an example for carrying charges.

6035 – Other Interest Expense

1508 – Sub-account SSG EPC Contract Liquidated Damages

To record the carrying charges if there is a credit balance owing to customers at year end.

Appendix I – 2023 COS Accounting Order

Account 1508 – Other Regulatory Assets, Sub-account Sault Smart Grid Project Recovery Mechanism Variance Account

PUC Distribution Inc.

2023 Cost of Service Application – Sault Smart Grid Project Recovery Mechanism Variance Account

EB-2022-0059

Accounting Order

Account 1508 Other Regulatory Assets

Sub-accounts SSG Project Recovery Mechanism Variance Account

March 10, 2023

PUC Distribution Inc. - 2023 Cost of Service Application

Accounting Order

Account 1508 Other Regulatory Assets, Sub-account SSG Project Recovery Mechanism Variance Account

PUC shall establish Account 1508 – Other Regulatory Assets, Sub-account Sault Smart Grid ("SSG") Project Recovery Mechanism Variance Account and a corresponding carrying charge sub-account effective May 1, 2023.

This purpose of the sub-account is to record an asymmetrical true-up for the recovery of the SSG Project to the benefit of ratepayers for the period of May 1, 2023 to April 30, 2028. The mechanics are of this true-up are described under #1 below. PUC's net recovery for the SSG Project for this period, after considering this sub-account, will be the lower of

a) total rate riders collected from May 1, 2023 to April 30, 2028; and
b) the sum of 2023 to 2027 revenue requirements, where the annual revenue requirement is the lower of i) the recalculated revenue requirement based on actual SSG Project capital costs and in-service dates ("Actual Revenue Requirement"), and ii) the settled forecasted revenue requirement used to calculate the SSG Recovery Mechanism Rate Rider ("Settled Revenue Requirement").

This sub-account will be a Group 2 account and the balance will be requested for disposition at PUC's next Cost of Service application with carrying charges applied at the OEB's prescribed rate. The sub-account will be closed upon disposition of the balance, if any.

1) Account 1508 Other Regulatory Assets, Sub-account SSG Project Recovery Mechanism Variance Account

Annually, the lower of the Actual Revenue Requirement and the Settled Revenue Requirement will be identified ("Lower Revenue Requirement"). Once the annual Lower Revenue Requirement is identified, the Lower Revenue Requirement will be recorded in the sub-account. The rate riders collected for that year will also be recorded in the sub-account as an offset. This net effect in the sub-account will be:

- If the annual Lower Revenue Requirement is less than rate riders collected for that year, a credit amount equalling the difference between the two will be recorded in the sub-account.

- If the annual Lower Revenue Requirement is greater than rate riders collected for that year, a debit amount equalling the difference between the two will be recorded in the sub-account.

If the cumulative amount recorded in the sub-account is a credit amount on April 30, 2028, the credit amount will be returned to ratepayers. Conversely, if the cumulative amount recorded in the sub-account is a debit amount, the debit amount will not be disposed and the balance in the sub-account will not be recoverable from ratepayers and will be written off.

2) Account 1508 Other Regulatory Assets, Sub-account SSG Project Recovery Mechanism Carrying Charges

Carrying charges shall be recorded monthly in this sub-account, calculated using simple interest applied to the opening balances in the SSG Project Recovery Mechanism Variance Account sub-account. The interest rate shall be at the OEB's prescribed rate. This sub-account will be disposed of if there is a credit balance. Otherwise, the balance in the sub-account will not be disposed and the balance in the sub-account will be written off.

EXAMPLE WITH JOURNAL ENTRIES

An illustrative example with journal entries associated with the SSG Project and SSG Project Recovery Mechanism Variance Account.

1) Cost Assessment (no entry)	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**
	Actual Cost Higher Than Settlement Cost					
Settled Revenue Requirement	1,000	1,000	1,000	1,000	1,000	5,000
Actual Revenue Requirement	700	700	700	700	700	3,500
Lower of Settled or Actual Rev Requirement	700	700	700	700	700	3,500

2) Over collection True-Up Asymmetrical on Aggregate Basis entry	**2023**	**2024**	**2025**	**2026**	**2027**	**Total 2023 to 2027**
	Collected More Than Settled Rev Requirement in Total					
Rate Riders Collected	800	500	1200	600	1300	4,400
Lower of Settled and Actual Rev Requirement	700	700	700	700	700	3,500
Account 1508	- 100	200	- 500	100	- 600	- 900 Refund

PUC Actual Total Recovery	3,500

Sample cumulative journal entries that will be recorded annually:

1180 – Accounts Receivable/1005 – Cash	$4,400	
1508 – Other Regulatory Assets – SSG Project Recovery Mechanism Variance Account		$4,400

To record the SSG Recovery Mechanism Rate Rider received, for SSG Revenue Requirement

1508 – Other Regulatory Assets – SSG Project Recovery Mechanism Variance Account	$3,500	
4080 – Distribution Revenue		$3,500

To record the annual "Lower Revenue Requirement" for SSG Revenue Requirement

6035 – Other Interest Expense	$xx	
1508 Other Regulatory Assets, SSG Project Recovery Mechanism Carrying Charges		$xx

To record carrying charges on a credit balance in the DVA.

1508 – Other Regulatory Assets, SSG Project Recovery Mechanism Carrying Charges	$xx	
4405 – Interest and Dividend Income		$xx

To record carrying charges on a debit balance in the DVA.

Appendix J – PUC's Response to OEB Order #6

APPENDIX H

PUC’s Response to OEB

Order #6

The following is the methodology and targets outlined for each category in OEB Order number 6 from the decision and order for EB-2018-0219/2020-0249. This response forms part of the Distribution System Plan, Section 5.3.6.2.3 (Pg 94).

5.3.6.2.3 PUC's Response to OEB Order #6

The SSG project performance metrics being developed are summarized in the following table and referenced appendices. There are three metric categories in Table 1: SSG Project Performance Metrics; (1) Green House Gas ("GHG") emissions reduction, (2) Improved asset utilization and increased (energy) efficiency, and (3) Increased reliability and resiliency. The main direct measurable metrics are "Energy Savings", which is also an input to GHG emissions reduction, and reliability improvement, that will be developed for measurement purposes with the SSG project and used to derive other metric calculations. As noted, certain measures are intended more as trending performance indicators than targets which will require development and data analysis over a longer-term period.

Table 1: SSG Project Performance Metrics

Area	Metric	Description	Target
GHG emissions reductions	Reduction in GHG Emissions	GHG emissions reduction from provincial generation sources achieved through the SSG VVO reduction in kWh energy use/purchase.	2860 (tCO_2e)
	Reduced energy losses from GHG emitting supply (kWh) (but not calculated directly)	Energy reduction of lower power purchase/supply by PUC applied to average provincial transmission grid loss factor means less energy production from provincial generation sources and additional GHG reduction.	Is Included in above GHG calculation
Improved Asset Utilization and increased energy efficiency	Reduction in peak demand on utility assets (kW)	Demand reduction (kW on station assets) will be measured as part of the VVO performance measurements.	Trending KPI's (kW and %)
	Reduction in energy losses (% of PP kWh)	The energy reduction achieved with the SSG VVO solution will reduce system losses in relation to the reduced energy delivery.	2.7% of system losses
	$ savings from deferred system upgrades	This measure requires further research on methodology and data collection and will be part of future asset management programs. The measure and associated target will be evaluated with asset management planning systems over the 2023-2027 DSP period.	Trending KPI TBD
	$ energy savings to customers (& kWh)	The VVO energy savings (kWh) and a total system average energy price (P_{AVG}) calculation.	2.7% kWh and $'s (calc)
Increased reliability and resiliency	# events Fault Location, Isolation and Restoration (FLISR) responded to	Utilize data captured in the Outage Management System (OMS) combined with data from SCADA report an event count and trending KPI.	FLISR Event Trending KPI

Area	Metric	Description	Target
	# Customer calls/ complaints avoided due to fewer outages	After review, PUC decided this metric would not be used as a satisfactory measurement method could not be determined.	N/A
	$ revenue loss avoided from outages avoided	Calculation/estimate from the customer minute reliability improvement metric multiplied by an average customer revenue value.	Calculated $'s
	NEW Reduced customer minutes of interruption (CMI)	Utilize the new OMS and SCADA system to calculate the difference in customer minutes of interruption (CMI) on feeders with DA deployed and an estimate of CMI that would have occurred without DA.	10% CMI

Energy Savings

The energy savings performance metric target is 2.7%. This metric applies to customers supplied from PUC's 12.5kV distribution system with VVO deployed and includes savings on annual kWh energy purchases of reduced customer consumption and energy losses. Guidance on development of the Measurement and Verification (M&V) methodology was drawn from the EPC design team and the IEEE 1885-2022[1] Standard. The VVO M&V methodology summary is provided in Appendix A.

An example of the annual calculation of the overall 2.7% target calculation is provided in Figure 1 below.

Figure 1: 2.7% Target Calculation

[Energy Savings (1)] / [Purchased Energy (2) + Energy Savings (1)]	e.g.	[17,456,712] / [617,414,778 + 17,456,712]	x 100% =	2.7%
(1) Annual kwh saved on 12.5 kV circuits deployed				
(2) Total System Purchased Energy less direct 34.5 kV customers				
The kWh values used in the example calculation are from the SSG ICM application Appendix AA14				

Calculations of savings to specific customer classes will utilize a proportional allocation initially and may evolve over time with future data analysis. It is unknown if statistically supported alternative allocation approaches or conclusions can be derived at this time. New data collected over future years of VVO operation may inform alternative methods for customer class specific benefit measurement. The methodology developed for the ICM energy savings financial benefit estimate (ICM Appendix AA14), attached as appendix C, will be applied with new annual actual data each year.

The kWh energy savings will also be used as an input value in calculation of GHG emission reductions.

- Reduction in GHG Emissions (tCO2e), and
- Reduced energy losses from GHG emitting supply (kWh)

[1] IEEE 1885-2022 Guide for Assessing, Measuring and Verifying Volt-Var Control Optimization on Distribution Systems.

GHG Emission Calculations

National Resources Canada ("NRCan") has developed a Smart Grid Program GHG Project Accounting Template for use in reporting by program participants. The on-line reporting template was issued earlier in 2022 to begin implementation. PUC submitted our initial data in July 2022 in the template and is currently in the validation phase with the program administrators.

The following figure is from the NRCan reporting template and has the GHG estimates developed by PUC and submitted to NRCan for the project.

Figure 2: NRCan Reporting Template

CALCULATIONS FOR SSR ELEMENT P1			
Parameter/Variable	Value	Unit	Source documents and notes
PUCD energy savings	17456712	kWh/year	PUCD ICM rate application records - VVM Energy Savings Estimate
Electricity Sector GHG Emissions	5500000	tCO2e/year	IESO Annual Planning Outlook Report (2020) - Figure 37
IESO Annual Energy Demand	1.446E+11	kWh/year	IESO Annual Planning Outlook Report (2020) - Figure 2
Ratio Annual/Marginal Emission Factor	4.32		PUCD ICM rate application records - SSG GHG Emission Estimate with MEF
x Emission factor	0.000164315	tCO2e/kWh	Marginal emission factor (MEF)
Emissions from P1 (annual)	**2868.405789**	**tCO2e/year**	

[Estimated Energy Savings (1)] * [Ontario Energy/Ontario GHG) (2)] * [[AEF/MEF]		[17,456,712] * [5500MtCo2e/1.446TWh] *[4.32]	=	2868
(1) on 12.5 kV circuits with VVO deployed				
(2) From IESO Annual Outlook Report				
(3) Ratio of Marginal Emission to Average Emission factors - TAF Report				

PUC's understanding of IESO data suggests GHG savings from the provincial transmission grid would be included in IESO reporting so it is not directly calculated.

PUC has proposed to NRCan the same methodology for GHG savings calculations utilized in the SSG ICM (EB-2020-0249/EB-2018-0219) interrogatory responses to ED-1 filed on January 25, 2021 .

The proposed calculation of subsequent year savings would be updated with new input factors from PUC calculated energy savings and new IESO and industry data on provincial source emission factors. A ten-year forecast using current IESO data is in table 2 below.

Table 2: Ten Year Forecast of Project GHG Savings

YEAR	Project emissions (tCO2e/year)
2023	2,151
2024	2,861
2025	2,861
2026	2,861
2027	2,861
2028	2,861
2029	2,861
2030	2,861
2031	2,861
2032	2,861
2033	2,861

Reliability Improvement

Reliability performance metrics are focused on positive trending over time of customer minutes of improved reliability on an event-based calculation. Each outage event with Distribution Automation FLISR and DA action will be tracked, and calculations of improved customer minutes of interruption performed. An added row to the table has been included for Reduced Customer Minutes of Interruption (CMI). Calculations for normal scorecard metrics of SAIDA and SAIFI will also be completed. The Reliability Improvement Methodology Summary is provided in Appendix B.

Development of Metric Detailed Procedures

The previously referenced ‘A’ and ‘B’ appendices for the energy savings and reliability metrics provide a summary level description of the methodology being used. Ensuring efficient and sustainable metric measurement requires documented detailed methodology with standard operating procedures, data and security management, report development, etc. which will be developed and integrated into the new SCADA and OMS systems as part of the scope of work of the EPC contractor engaged for the project.

Other future Metrics and KPI’s

Determination of additional and new Key Performance Indicators and metrics are expected to evolve over time with new data collection based on the primary metrics outlined above. Data captured in the new Outage Management System and SCADA data historian along with potentially other data sources will with future analysis support ongoing efficiency efforts in operations, maintenance, and asset management areas.

With substantial completion of the new systems and assets in-service and operating by the end of 2022 the initial VVO testing, measurement, and fine tuning is expected to occur early in 2023. The first set of metric reporting of energy savings, GHG emissions and reliability improvements for the initial 2023 operation year will align with the annual RRR reporting period for 2023 in April 2024.

Appendix A

VVO M&V Methodology Summary

Appendix A. VVO M&V Methodology Summary

IEEE 1885-2022 identifies several measurement and verification methods that could be used after implementing Volt-VAr Optimization (VVO) or Conservation Voltage Reduction (CVR) to confirm whether the expected energy savings benefit is being achieved using Equation 1:

$$CVR_F = \frac{\frac{\Delta E}{E_0}}{\frac{\Delta V}{V_0}} = \frac{\%\ Change\ in\ Energy}{\%\ Change\ in\ Voltage} \qquad \text{Equation 1}$$

Where solving for "*% Change in Energy*" provides the expected energy savings benefit as follows:

$$\%\ Change\ in\ Energy = \ CVR_F * (\%\ Change\ in\ Voltage)$$

For the change needed in *"% Change in Voltage*", a normal operating voltage is needed in order to determine the percentage of change. For example, a PUC average system voltage is approximately 126 Volts on a 120 Volt basis. So, a new average system voltage of 122 Volts results in a 3.2% change in voltage.

PUC will use an "on-off" methodology from IEEE 1885-2022 to perform verification. The "on" part of the methodology will have PUC lowering the voltage by at least 3%[2] and measuring the energy used. The "off" portion of the methodology will have PUC returning the voltage to what has been the normal operating practice that results in an average system voltage of approximately 126 Volts. The resulting percentage change in energy used and voltage during each period is calculated in Equation 2 and Equation 3:

$$\%\ Change\ in\ Energy = \frac{\Delta E}{E_0} = \frac{E_{ON}\ \text{-}\ E_{OFF}}{E_{OFF}} \qquad \text{Equation 2}$$

Where:

E_{ON} Energy used during the "on period"
E_{OFF} Energy used during the "off period"

$$\%\ Change\ in\ Voltage = \frac{\Delta V}{V_0} = \frac{V_{ON}\ \text{-}\ V_{OFF}}{V_{ON}} \qquad \text{Equation 3}$$

Where:

V_{ON} Average Voltage during the "on period"
V_{OFF} Average Voltage during the "off period"

The changes in voltage and energy are direct measurements and result in the ability to calculate CVR_f. Reporting of CVR_f, "% Change in Energy", and "% Change in Voltage" provides standard industry metrics that can then be compared with other published results from other utilities.

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[2] IEEE 1885-2022 Guide for Assessing, Measuring and Verifying Volt-Var Control Optimization on Distribution Systems. - recommends a minimum of 3% voltage reduction for an on-off methodology.

Appendix B

Reliability Improvement Methodology Summary

Appendix B. Reliability Improvement Methodology Summary

The measurement of reliability improvement through implementation of Distribution Automation (DA) technologies recognizes two main benefit elements but only the first will be used in the calculation. The first is a data driven calculation of customer outage minutes captured in SCADA and the Outage Management System (OMS) that will calculate a percentage reliability improvement. The second is more subjective and recognizes the improved ability to isolate and determine the fault location on a reduced feeder section as well as a much broader situational awareness in the more wide-spread storm related system outages to improve direct field crew response time and improve customer communications.

The data calculation methodology is described below.

The SCADA/OMS will have integration to GIS/AMI meter and customer data. This provides the feeder location and number of initial customers "C_I" for an initial outage event.

DA action will provide a automated partial restoration to some customers "C_M" who only experience a momentary outage while remaining customers "C_S" experience a sustained outage.

$$C_I - C_M = C_S$$

Upon restoration the customer minutes of interruption "CMI" can be determined for each of the customer groups above utilizing the start and finish timestamp *"TS"* data from the SCADA/OMS.

$C_I \times TS = CMI_I$ *(customer minutes of interruption of initial outage - no DA operation)*

$C_S \times TS = CMI_S$ *(customer minutes of interruption of sustained customers)*

Summation of above CMI calculations for all outage events can then be used to allow calculation of annual percent reliability improvement in relation to customer minutes of interruption as well as for the Scorecard SCADI and CAIDI reliability metrics.

As example, annual calculation of SAIDI and CAIDI reliability metrics are completed in normal manner for both factors above across all outage events to generate initial $SAIDI_I$ and $CAIDI_I$ and sustained $SAIDI_S$ and $CAIDI_S$ values all referred to as "METRIC" below. Calculation as illustrated below will provide the improved reliability performance from DA.

$$\%\ Improved\ Reliability = \frac{METRIC_I \text{ - } METRIC_S}{METRIC_I}\ X\ 100\%$$

Appendix C

ICM (EB-2018-0219/EB-2020-0249)
Amended Application Appendix AA14
VVM Energy Savings Estimate

Appendix AA14
VVM Energy Savings Estimate Spreadsheet
(Live Excel model filed with Amended Application)

Energy Savings Estimated from VVM System

1. Table below is from 2018 CoS application with normalized load forecast.

2018 CoS Rate Application Data						Loss Factor	1.0481	
	Total Base Revenue Requirement	Class %	Number of Customers	2018 Test Year Weather Normal kWh (Load Forecast)	Class %	kW	2018 Test Year Weather Normal (kWh w/LF)	Class %
Res	$ 11,226,807	58.50%	29,816	288,323,799	45.85%		302,192,174	45.85%
GS<50kW	$ 3,149,458	16.41%	3431	92,411,463	14.69%		96,856,454	14.69%
GS>50kW	$ 4,544,464	23.68%	357	244,620,598	38.90%	614,743	256,386,849	38.90%
Sentinel lights	$ 34,742	0.18%	354	209,800	0.03%	593	219,891	0.03%
Street lights	$ 195,345	1.02%	8070	2,398,221	0.38%	7,030	2,513,575	0.38%
USL	$ 39,551	0.21%	22	944,731	0.15%		990,173	0.15%
	$ 19,190,367	100.00%		628,908,612	100%		659,159,116	100%

2. VVM Energy Savings estimate is only applicable to customers on the 12.5 kV distribution network with intended design & application.
3. A reduction of the energy consumption above in the GS>50kW customers connected to the 34.5kV subtransmission network is thus needed .
4. The 7 customers for above annual energy consumption was totaled across two years and an average of 41,744,343.60 kWh used.
5. Note: as actual consumption in period was above Normalized this creates a more conservative estimate on total energy saved by VVM.
6. The Table below shows where the reduction applied results in 617,414,773 kWh energy for VVM targeted customers on the LV customers.

2018 CoS Rate Application Data - adjusting 34.5kV load						Loss Factor	1.0481			
	Total Base Revenue Requirement	Class %	Number of Customers	2018 Test Year Weather Normal kWh (Load Forecast)	Class %	kW	2018 Test Year Weather Normal (kWh w/LF)	Class %	Reduce GS>50kW 34.5kV (no VVM)	LV Feeder Energy Consumption Base for VVM
Res	$ 11,226,807	58.50%	29,816	288,323,799	45.85%		302,192,174	45.85%		302,192,174
GS<50kW	$ 3,149,458	16.41%	3431	92,411,463	14.69%		96,856,454	14.69%		96,856,454
GS>50kW	$ 4,544,464	23.68%	357	244,620,598	38.90%	614,743	256,386,849	38.90%	41,744,344	214,642,505
Sentinel lights	$ 34,742	0.18%	354	209,800	0.03%	593	219,891	0.03%		219,891
Street lights	$ 195,345	1.02%	8070	2,398,221	0.38%	7,030	2,513,575	0.38%		2,513,575
USL	$ 39,551	0.21%	22	944,731	0.15%		990,173	0.15%		990,173
	$ 19,190,367	100.00%		628,908,612	100%		659,159,116	100%	16.3%	617,414,773

7. The Cost of Power forecast from the 2018 CoS rate Applcation was used in original application for estimating energy $ savings.

2018 CoS Cost of Power (CoS Application)

	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU		GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Cost of Power (COP*)	$77,725,426	$35,945,091	$11,467,389	$29,880,767	$0		$0	$0	$288,889	$25,865	$117,425
(*) gross w/loss factor											
REDUCE GS>50kW by 16.3%				$ 4,865,121							
Revised COP	$72,860,305	$35,945,091	$11,467,389	$25,015,646	$0		$0	$0	$288,889	$25,865	$117,425
Estimate for VVM customers											

8. Table below uses the current Cost of Power forecast with updated IESO rates as provided below and the 16.3% reduction in energy from the GS>50kW class kWh used to get balance for VVM customers.

2020 CoS Cost of Power (uses 2019 IESO rates)

	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU		GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Cost of Power (COP*)	$88,047,743	$40,624,176	$12,936,129	$33,995,412	$0		$0	$0	$330,827	$29,119	$132,080
(*) gross w/loss factor	$ 0.1336	*Avg rate*									
REDUCE GS>50kW by 16.3%				$ 5,535,058							
Revised COP	$82,512,685	$40,624,176	$12,936,129	$28,460,354	$0	$0	$0	$0	$330,827	$29,119	$132,080
Estimate for VVM customers											

9. Next table describes the VVM energy and $ savings estimated to be achieved by the VVM system.

ENTER VALUES	***CVR factor***	0.9			System Energy Loss Savings Estimate kWh			2.60%	786,513		
	Voltage Savings	3.0	volts		Using avg $/kWh from COP			$ 0.1336	$ 105,111		
	Energy Savings	2.7	%								
Total $'s saved with VVM	$2,227,842	$1,096,853	$349,275	$768,430	$0	$0	$0	$0	$8,932	$786	$3,566
Total VVM w/Syst losses included	***$2,332,954***										
Total kWh saved with VVM	16,670,199	8,159,189	2,615,124	5,795,348	-	-	-	-	67,867	5,937	26,735
Total kWh saved with losses incl.	***17,456,712***										

PUC Distribution Inc. (“PUC”)

EB-2022-0059

Responses to Pre-Settlement Clarification Questions

March 10, 2023

Without Prejudice and Confidential

Contents

Ontario Energy Board (OEB) Staff

1-Staff-112

Tree Trimming
Ref 1: IRR 1-Staff-9
Ref 2: IRR VECC-30

Question:

The response in reference 1 states that with respect to vegetation management, PUC Distribution continues using a similar cycle management process, which consists of the service territory being divided into four similarly sized sections completed over a four-year cycle.

The response to reference 2 provides the following table with respect to tree-trimming expenses:

Year	2018 Approved	2018	2019	2020	2021	2022 Budget	2023 Test
5135 – Right of Way	$693,011	$621,970	$617,322	$651,631	$824,518	$772,070	$851,608

(a) Please provide the 2022 year-to-date actuals.
(b) Please provide the drivers for the 2023 budget to be approximately $155k over the historical average.

Response:

a) The 2022 YTD actuals as of October 31, 2022, is $543,825.
b) The amount reported for the 2023 test year in the table above included amounts from Account 5125 in error. The revised Account 5135 amount for the 2023 test year is $733,747. With this correction, the 2023 budget is in line with the historical average.

Year	2018 Approved	2018	2019	2020	2021	2022 Budget	2023 Test Updated
5135 – Right of Way	$693,011	$621,970	$617,322	$651,631	$824,518	$772,070	$733,747

<u>1-Staff-113</u>

Ref 1: IRR 1-Staff-10(c)

<u>Question:</u>

The interrogatory asked if PUC Distribution had considered both the implications on the availability of and the expected rates for debt that **could not (emphasis added)** be obtained through Infrastructure Ontario (IO). Further, the interrogatory requested that PUC Distribution describe the risks, and how PUC Distribution intends to mitigate those risks should that become a circumstance faced by the utility.

The response to the interrogatory confirmed that "loans 2-7 have already been committed as a preapproval from IO as a revolving credit facility. PUC has also closely monitored the fluctuating rate situation by keeping in frequent contact with its IO financing representative."

Please explain if PUC Distribution considered both the implications on the availability of and the expected rates for debt that could not be obtained through IO, describe the risks, and how PUC Distribution intends to mitigate those risks should that become a circumstance faced by the utility.

<u>Response:</u>

PUC has already secured the financing by way of a revolving credit facility with Infrastructure Ontario (IO). Therefore, there is no risk to PUC with respect to availability of debt from IO. As noted in the original response, PUC closely monitors expected rates and views the level of risk associated with rate fluctuations as low.

<u>**2-Staff-114**</u>

Cost of Power
Ref 1: IRR 2-Staff-21(d)
Ref 2: Chapter 2 Appendices, November 28, 2022, Tab 2-ZB
Ref 3: Revenue Requirement Workform (RRWF), November 28, 2022, Tab 3

<u>Question:</u>
The response to reference 1 states that the cost of power has been updated to match the Ontario Electricity Rebate (OER) of 11.7%.

OEB staff notes that the Chapter 2 Appendices filed with PUC Distribution's responses (reference 2) shows an OER rate of 17% in cell B165 on Tab 2-ZB. Further, Tab 3 of the RRWF indicates a cost of power of $60,391,013 in the "Interrogatory Responses" column. Tab 2-ZB (prior to the correction of the OER) shows an amount of $58,540,344.

Please reconcile both matters and file corrected models as required.

<u>Response:</u>

The Chapter 2 Appendices, Appendix 2-ZB has been corrected to show the correct OER rate of 11.7%.

In response to VECC 56, the load forecast has also been updated. A revision to the consumption used in the chapter 2 Appendices, Appendix 2-ZB results in a revised cost of power of $60,482,027.

<u>2-Staff-115</u>

Sault Smart Grid – Reprioritization
Ref 1: IRR 2-Staff-25
Ref 2: IRR VECC-8

<u>Question:</u>

PUC Distribution stated that the original SSG scope did not specifically include the renewal of transformers, switchgear, and on-load tap changers. It appears that part of the funds from deferral of Substation 22 were redirected to the "Switchgear P&C" and "Distribution Station" programs. It is staff's understanding from the response in reference 1 and 2 that the costs for the renewal of six transformers and primary switchgear at three of PUC Distribution's existing distribution stations (Substation 2, 11, and 20) are included under the "Switchgear P&C" and "Distribution Station" programs. The reason that they were replaced was due to asset condition, but the replacement also benefitted from NRCan funding eligibility as the replacement can also be considered "in-scope" of the SSG even though not included in the $28.7 million.

(a) Please confirm if OEB staff's understanding is correct. If not, please correct OEB staff's understanding.

(b) If so, provide a breakdown for the "Switchgear P&C" and "Distribution Station" programs between the cost of the renewal of six transformers and primary switchgear at three of PUC Distribution's existing distribution stations and other project costs.

(c) Please provide the calculation of the NRCan funding and the project costs before the NRCan funding for the renewal of six transformers and primary switchgear at three of PUC's existing distribution stations.

<u>Response:</u>

a) PUC can confirm that the incremental costs of six power transformers compared to six voltage regulators for Substations 2, 11, and 20 and the cost of one 34.5kV switchgear for Substation 20 is being contributed to SSG by PUC's capital programs. The OEB staff's understanding of the reasoning and NRCan funding eligibility is correct.

b) The incremental cost of six power transformers versus six voltage regulators is in the 2022 Distribution Station Transformation program budget and the cost of one 34.5kV switchgear is in the 2022 Distribution Station Switchgear P&C program budget. The current estimate for the incremental transformer costs is $3M, which is net of NRCan contribution of $1M. The current estimate for the switchgear costs is $0.5M, which is net of NRCan contribution of $0.16M.

c) NRCan funding of 25% was used for calculating the costs in answer (b) above. Prior to applying NRCan funding, the current estimate for the incremental transformer costs is $4M. Prior to applying NRCan funding, the current estimate for the switchgear costs is $0.66M.

2-Staff-116

Reliability
Ref: IRR 2-Staff-30

Question:

PUC Distribution showed that the majority of the outages were due to conductor-related failures.

Please confirm if most of these conductor-related failures are from restricted conductors.

Response:

PUC has had a program in place for a number of years and continues to replace restricted wire and it now consists of a small proportion of wire in our system. Accordingly, most of the conductor-related failures are not from restricted wire conductors.

<u>2-Staff-117</u>

Station Renewal
Ref: IRR 2-Staff-39

<u>Question:</u>

PUC Distribution stated that the increase in budget is due to higher copper theft in recent years. PUC Distribution also pointed out that the DAI for 6 station buildings is below the threshold and the costs are reflective of extra environmental controls and work methods required to complete the work.

(a) Copper theft is an issue that utilities have seen for many years. While PUC Distribution has seen an increase in copper theft in recent years it was not always as high. Please explain why it would not be more appropriate to average the costs PUC Distribution seen for fence repair over the five years. Especially with the addition of security cameras**.**

(b) Please explain if PUC Distribution intends to improve the DAI score for station buildings. If not, why not?

(c) Has PUC Distribution sandblasted or painted any units in the past 5 years? If so, please provide the year and cost.

<u>Response:</u>

a) A larger proportion of the increased cost is related to the sandblasting, painting and repairs of deteriorated switchgear and metal clad station buildings. In addition, to save project administration costs and to benefit from economies of scale, the work associated with the building exhaust fan ESA directive for multiple substations will be completed as one project and therefore 2023 is slightly greater than other years.

b) Yes, PUC intends to improve the DAI score by implementing the recommendation in section 6.3.2 of Appendix H of the Distribution System Plan.

c) PUC has not sandblasted or painted any units in the past 5 years.

2-Staff-118

Transmission Station Improvement
Ref: IRR 2-Staff-52

Question:

PUC provided proposed investments for 2023 in the Transmission Station Improvement investment.

Please provide the expected costs for this investment between 2024 to 2027, if any.

Response:

Please see table below:

Year of Proposed Investment		2024	2025	2026	2027
Transformer Stations	Unplanned renewal of Transformer Station assets - emergency repairs upon failure	$ 76,353	$ 77,669	$ 81,829	$ 76,422
	Planned - Transformer Station building and fence repairs	$ 12,726	$ 12,945	$ 13,638	$ 12,737
	Planned - Transformer Station Transformation	$ -	$ -	$ -	$ -
	Planned - TS rebuild (Engineering)	$ -	$ -	$ 136,381	$ 127,370

2-Staff-119

SSG
Ref: 2-Staff-19

Question:
In response to 2-Staff-19, PUC Distribution indicated that the SSG depreciation of $550,407 in Account 1508, Sub-account ICM SSG Depreciation includes 4 months of depreciation and 2022 depreciation of $300,244.

(a) Please explain what period the 4 months of depreciation pertains to.
(b) Please explain whether the 4 months of depreciation is reflected in the fixed asset continuity schedule (Appendix 2-Ba).
    a. Please indicate the annual depreciation pertaining to the SSG assets reflected in the fixed asset continuity schedule up to Dec. 31, 2023.
(c) Please confirm that half-year depreciation was used in the year the SSG assets were in service.

Response:

a) The 4 months of depreciation pertains to January 1, 2023 to April 30, 2023.

b) The 4 months of depreciation is not reflected in the fixed asset continuity schedule Appendix 2-BA.
    a) The annual depreciation pertaining to the SSG assets reflected in the fixed asset continuity schedule of the Chapter 2 Appendices is $300,244 as of the end of 2022. There is an additional $642,290 in 2023.

c) The half-year rule for depreciation was used in 2022 for the amount of SSG assets placed in service in that year. In 2023, the half-year rule was used on the 2023 SSG additions and a full year depreciation on the 2022 SSG assets placed into service.

<u>**2-Staff-120**</u>

Substation 16 ICM True-up
Ref 1: 2-Staff-20
Ref 2: Exhibit 2, pages 59-64

<u>Question:</u>

(a) In response to 2-Staff-20a regarding the Substation 16 ICM, PUC Distribution indicated that it updated the ICM capital spend, depreciation and CCA in tab 9b of the ICM model approved in its ICM proceeding.[1] OEB staff reperformed these updates and obtained the following results as compared to PUC Distribution's results in Table 2-27

Column E of ICM model	**Table 2-27 ($)**	**Recalculated by OEB staff ($)**
Amount of Project Claimed	3,894,622	2,602,851
Depreciation	97,366	65,071
CCA	155,785	104,114
Revenue requirement	356,932	238,544

In OEB staff's recalculation, the Amount of Capital Project Eligible for ICM (cell E25) remains unchanged at $2,602,851 as the ICM capital spend of $6,020,000 is limited to the $2,602,851 of maximum eligible incremental capital as shown on tab cell G20. Please provide PUC Distribution's ICM excel model and clarify how PUC Distribution calculated the ICM revenue requirement based on actuals in Table 2-27.

(b) Please recalculate the actual ICM revenue requirement using the half-year rule in 2021, then full-year in 2022, based on the below and provide the associated ICM excel model.
    i. no change in maximum eligible incremental capital from the approved amount**.**
    ii. actual costs, depreciation and CCA excluding the amounts related to COVID-19 related expenses of $176k.
    iii. actual depreciation, considering the 4 months of depreciation as noted in response to 2-Staff-19.
    iv. updated forecasted rate riders collected to April 30, 2023 ($713,103 per SEC-9 or $731,193 sum of Account 1508, Sub-account Substation 16 Rider and Account 1509, Sub-account COVID-19 Foregone Revenue for Substation 16 per IRR DVA Continuity Schedule)**.**

[1] EB-2019-0170

(c) Please compare the recalculated revenue requirement to actual rate riders collected.
(d) Please provide the actual costs, depreciation and CCA excluding COVID-19 related amounts.

<u>Response:</u>

(a) PUC has provided the live ICM excel models as Appendix G with these pre-settlement clarification responses. In cell G16 the new CAPEX amount is now $10,392,266 instead of $9,100,376. This increase of $1,291,890 is from the additional spending on Substation 16. This changes the maximum eligible incremental capital in cell G20 to $3,894,741 from $2,602,851. PUC has provided a snapshot below of Tab 9b of the ICM Model.

	Cost of Service Test Year 2018	*Price Cap IR* Year 1 2019	*Price Cap IR* Year 2 2020
CAPEX[1]	$ 4,938,176	$ 5,770,421	$ 10,392,266
Materiality Threshold		$ 6,445,056	$ 6,497,525
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ -	$ 3,894,741

		Test Year 2018	Year 1 2019			Year 2 2020		
Project Descriptions:	Type		Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA
Substation 16 Rebuild	New ICM					$ 6,020,119	$ 150,503	$ 240,805

These inputs create the incremental revenue requirement of $356,943 on tab 10 of the ICM model.

(b) Using the same ICM Model filed in part "a", PUC updated tab 9b to the following information below:

i. Cell G16 was not changed from the original file amount of $9,100,376 as shown below.

	Cost of Service Test Year 2018	*Price Cap IR* Year 1 2019	*Price Cap IR* Year 2 2020
CAPEX[1]			
Materiality Threshold		$ 6,445,056	$ 6,497,525
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ -	$ 2,602,851

		Test Year 2018	Year 1 2019			Year 2 2020		
Project Descriptions:	Type		Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA
Substation 16 Rebuild	New ICM					$ 6,020,119	$ 150,503	$ 240,805

ii. Cell G25 in this scenario is $176,000 less than $6,020,119. This revises the depreciation to $146,103 and CCA to $467,530. This can be seen in the snapshot of tab 9b below.

		Cost of Service	*Price Cap IR*			*Price Cap IR*		
		Test Year 2020	Year 1 2021			Year 2 2022		
CAPEX[1]		$ 4,938,176	$ 5,770,421			$ 9,100,376		
Materiality Threshold			$ 6,445,056			$ 6,497,525		
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)			$ -			$ 2,602,851		
		Test Year 2020	Year 1 2021			Year 2 2022		
Project Descriptions:	Type		Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA
Substation 16 Rebuild	New ICM					$ 5,844,119	$ 146,103	$ 467,530

iii. The response in OEB Staff-19 relates to depreciation of SSG assets and not Substation 16.

iv. PUC has revised the forecast revenue requirement collection. The total forecasted collection to April 30, 2023, in 1508 ICM revenue, is $584,857 and the total forecasted collection in 1509 foregone ICM revenue to November 30, 2022, is $101,711.29. Therefore, the total collection in ICM revenue is $686,568. This has been revised in the DVA continuity schedule.

(c) The recalculated revenue requirement is $100,503 in 2021 which uses the following inputs on Tab 9b and output from tab 10.

<u>Figure: Tab 9b Half Year</u>

		Cost of Service	*Price Cap IR*			*Price Cap IR*		
		Test Year 2018	Year 1 2019			Year 2 2020		
CAPEX[1]		[illegible]	[illegible]			[illegible]		
Materiality Threshold			$ 6,445,056			$ 6,497,525		
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)			$ -			$ 3,894,741		
		Test Year 2018	Year 1 2019			Year 2 2020		
Project Descriptions:	Type		Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA
Substation 16 Rebuild	New ICM					$ 3,010,060	$ 75,251	$ 120,402

Figure: Tab 10 Half Year

Current Revenue Requirement

Current Revenue Requirement - Total		$	19,273,165	A

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim		Eligible for ACM/ICM (Half Year* Prorated Amount (from Sheet 10b)		
Amount of Capital Projects Claimed	$ 5,844,119	$	1,301,426	B
Depreciation Expense	$ 146,103	$	32,536	C
CCA	$ 467,530	$	104,114	V

The half year rule is applied as the distributor is scheduled to rebase in the next rate year.

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	1,301,426	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$	32,536	C
Incremental Capital to be included in Rate Base (average NBV in year)			$	1,285,158	D = B - C/2
	% of capital structure				
Deemed Short-Term Debt	4.0%	E	$	51,406	G = D * E
Deemed Long-Term Debt	56.0%	F	$	719,688	H = D * F
	Rate (%)				
Short-Term Interest	2.29%	I	$	1,177	K = G * I
Long-Term Interest	4.12%	J	$	29,651	L = H * J
Return on Rate Base - Interest			$	30,828	M = K + L
	% of capital structure				
Deemed Equity %	40.00%	N	$	514,063	P = D * N
	Rate (%)				
Return on Rate Base -Equity	9.00%	O	$	46,266	Q = P * O
Return on Rate Base - Total			$	77,094	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	$	32,536	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$	46,266	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$	32,536	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$	104,114	V
Incremental Taxable Income			-$	25,313	W = T + U - V
Current Tax Rate	26.5%	X			
Taxes/PILs Before Gross Up			-$	6,708	Y = W * X
Grossed-Up Taxes/PILs			-$	9,126	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	77,094	AA
Amortization Expense - Total	S	$	32,536	AB
Grossed-Up Taxes/PILs	Z	-$	9,126	AC
Incremental Revenue Requirement		$	100,503	AD = AA + AB + AC

The recalculated revenue requirement is $201,007 for 2022 using the following inputs on tab 9b and output on Tab 10:

Figure: Tab 9b Full Year

		Cost of Service	*Price Cap IR*			*Price Cap IR*		
		Test Year	**Year 1**			**Year 2**		
		2019	**2020**			**2021**		
CAPEX[1]		$ 4,938,176	$ 5,770,421			$ 9,100,376		
Materiality Threshold			$ 6,445,056			$ 6,497,525		
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)			$ -			$ 2,602,851		
		Test Year	**Year 1**			**Year 2**		
		2019	**2020**			**2021**		
Project Descriptions:	**Type**		**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
Substation 16 Rebuild	**New ICM**					$ 5,844,119	$ 146,103	$ 467,530

Figure: Tab 10 Full Year

Current Revenue Requirement

Current Revenue Requirement - Total		$	19,273,165	A

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim		Eligible for ACM/ICM (Full Year Prorated Amount) *(from Sheet 10b)*	
Amount of Capital Projects Claimed	$ 5,844,119	$	2,602,851	B
Depreciation Expense	$ 146,103	$	65,071	C
CCA	$ 467,530	$	208,228	V

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	2,602,851	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$	65,071	C
Incremental Capital to be included in Rate Base (average NBV in year)			$	2,570,316	D = B - C/2
	% of capital structure				
Deemed Short-Term Debt	4.0%	E	$	102,813	G = D * E
Deemed Long-Term Debt	56.0%	F	$	1,439,377	H = D * F
	Rate (%)				
Short-Term Interest	2.29%	I	$	2,354	K = G * I
Long-Term Interest	4.12%	J	$	59,302	L = H * J
Return on Rate Base - Interest			$	61,657	M = K + L
	% of capital structure				
Deemed Equity %	40.00%	N	$	1,028,126	P = D * N
	Rate (%)				
Return on Rate Base -Equity	9.00%	O	$	92,531	Q = P * O
Return on Rate Base - Total			$	154,188	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	$	65,071	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$	92,531	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$	65,071	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$	208,228	V
Incremental Taxable Income			-$	50,625	W = T + U - V
Current Tax Rate	26.5%	X			
Taxes/PILs Before Gross Up			-$	13,416	Y = W * X
Grossed-Up Taxes/PILs			-$	18,253	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	154,188	AA
Amortization Expense - Total	S	$	65,071	AB
Grossed-Up Taxes/PILs	Z	-$	18,253	AC
Incremental Revenue Requirement		$	201,007	AD = AA + AB + AC

The total revenue requirement is $301,510 for 2022 and 2023 as compared to the projected rate rider revenue collected to April 30, 2023, of $686,568 resulting in a refund to customer of $385,058.

(d) Please see the figure in the response to b(ii).

<u>**3-Staff-121**</u>

COVID Adjustment
Ref: IRR 3-Staff-55(d)

<u>Question:</u>

OEB staff requested a scenario where wholesale purchases were unadjusted for COVID-19, but an explanatory variable was used capture and adjust for the impacts of the pandemic.

The supplied scenario included an explanatory variable for COVID-19, but the wholesale load forecast for 2020 still reflects 631,179,704 kWh, and 2021 still reflects 622,536,838 kWh.

Please re-run the scenario where the wholesale load does not include the adjustment for COVID-19.

<u>Response:</u>

PUC is unclear where OEB Staff states 631,179,704 kWh for 2020 and 622,536,838 for 2021. In the Load Forecast response to Staff 55(d), PUC removed the adjustment of 1,526,904 for each month in 2020 from the purchases column B on the Purchased Power Model tab. Consistently, PUC used the adjustment of 1,579,660 for 2021. With these adjustments, PUC reran the regression model after this change to produce a load forecast of 646,025,946 purchases for 2020 and 623,681,157 purchases for 2021.

Please note this version of the load forecast also does not include customer count as an explanatory variable.

3-Staff-122

Customer Reclassifications
Ref: IRR 3-VECC-18

Question:

PUC Distribution indicates that 72 customers were reclassified into the GS < 50 rate class in 2012.

Please indicate which customer classes these customers were in prior to re-classification**.**

Response:

These customers were in the large GS>50 rate class before being reclassed into GS<50.

<u>4-Staff-123</u>

Inflation Trends
Ref 1: IRR 4-Staff-61
Ref 2: Exhibit 4, page 9, table 4-3

<u>Question:</u>

PUC Distribution confirmed that:

- The inflation rates used for inflation trends were 3.0% and 7.4% for 2022 and 2023 respectively.
- The inflation factors for budgeting OM&A for 2022 and 2023 includes a 2.0% increase to unionized labour and a 3.0% increase to management labour.
- A general inflationary increase of 3.0% was applied to other non-labour related items where detailed estimating was otherwise unknown.
- Specific elements with known increases were included into budgeted OM&A costs for 2022 and 2023, some of which are significantly above 3.0% (e.g., insurance premiums).

Please itemize and quantify what categories had the highest specific inflationary increases forecasted for 2023 to get to a rate of 7.4%. In other words, please detail what accounts for the aggregate inflationary increase of 7.4% in the test year.

<u>Response:</u>

Significant known increases above the 3.0% inflationary rate included in the 2023 Test year are provided in the table below.

Account	Description
5010, 5085, 5615, 5620	Software
5335	Bad Debts
5675, 5365	Insurance
Various	Asset and Cost of Capital charges

<u>4-Staff-124</u>

CDM
Ref 1: Exhibit 4, page 55
Ref 2: IRR VECC-35(a)

<u>Question:</u>

At reference 1, PUC Distribution confirmed that no CDM costs are included in its test year revenue requirement.

The table provided in response to VECC-35 shows 0.31 Management FTE and 0.12 Non-Management FTE in line items "Conservation and Demand Management".

Chapter 2 of the Filing Requirement, page 33 states that the 2021 CDM Guidelines indicate that distributors should not request funding through distribution rates for dedicated CDM staff to support IESO programs. Further, an application must provide a statement confirming that no costs for dedicated CDM staff to support IESO programs funded under the 2021-2024 CDM Framework are included in the revenue requirement.

(a) Please reconcile the statement in reference 1 with the table provided in reference 2.
(b) Please confirm if CDM costs are included in its test year revenue requirement. If yes, please explain why and quantify.

<u>Response:</u>

(a) The response to VECC-35 was intended to identify the number of FTEs allocated to PUC from PUC Services. Portions of time for PUC Services employees were/are allocated to PUC's CDM activities for which recovery is provided through IESO funded programs and not through PUC's revenue requirement.

(b) There are no CDM costs included in the test year revenue requirement.

4-Staff-125

Green Button Implementation
Ref: IRR 4-Staff-64

Question:

PUC Distribution has included $21,000 in its OM&A expenses and an estimated capital cost of $80,000 related to the implementation of Green Button in the 2023 test year. PUC Distribution confirmed the use of an external third-party vendor.

(a) Please confirm if the selection of the vendor related to Green Button implementation was subject to an RFP process. If yes, please explain the selection process. If not, please explain why.
(b) Can PUC Distribution provide an estimate of the annual and monthly cost per customer for Green Button implementation?

Response:

(a) PUC's vendor for the Green Button was selected through an RFP process by invitation. Please find a copy of the RFP Green Button Implementation Contract No 22 04 006 which identifies the various milestones and approach provided in Appendix A.

(b) Please find the table below for the implementation and annual cost per customer.

	Cost	Number of Customers (2021)	Cost per Customer
Capital Cost of Implementation	$80,000	33,905	$2.36
Annual OM&A	$21,000	33,905	$0.62

6-Staff-126

Ref 1: IRR VECC-39(a)
Ref 2: Exhibit 4, Appendix B - Full Absorption Cost Allocation Review, pg. 18
Ref 3: Chapter 2 Appendices, November 28, 2022, Tab 2-H

Question:

For 2023, PUC Distribution used the OEB's revised cost of capital parameters released on October 20, 2022 as the basis of the calculation of the building return charge. This has increased the building return charge. The cost of capital parameters is applied to the average net book value of the building.

a) Please confirm if there have been any changes to the methodology to determine the 2023 proposed building charge as compared to the building charge as agreed to in PUC Distribution's 2018 cost of service (EB-2017-0071).
b) The increased building return charge for 2023 is shown in the top portion of Tab 2-H of the updated Chapter 2 Appendices. Please also make the parallel update to the bottom portion of the tab at cell O137.

Response:

a) There have been no changes to the methodology to determine the 2023 proposed building charge.

b) PUC has revised the Chapter 2 Appendices tab 2-H for this update. PUC also updated the pole rentals line in row 139 as this was also updated during the IRs.

<u>6-Staff-127</u>

CCA
Ref 1: 6-Staff-90
Ref 2: 6-Staff-90 excel PUCD - Bill C97 Accelerated CCA_Staff 90d_20221128
Ref 3: 6-Staff 90 excel PUCD - Bill C97 Accelerated CCA_Staff 90e_20221128
Ref 4: 6-Staff 89 excel PUC_IRR_Appendix IR16_PUCD_Bill C97 Accelerated CCA_20221128
Ref 5: IRR PILs Workform

<u>Question:</u>

In response to 6-Staff-90, PUC Distribution stated that the Omicron Injection Tester for $294,789 previously in Class 1 should be classified with a CCA rate of 8%. Subsequently, PUC Distribution stated that the 2023 Omicron Injection tester is now classified as CCA class 8. Class 8 has a CCA rate of 20%.

In tab T8 of the IRR PILs Workform, $294,754 is shown in Class 8 with a CCA rate of 20%. In the excels in reference 2, 3 and 4, the “2023-2027 Nov 28, 2022” tab shows $294,754 in Class 8 with a CCA rate of 8%.

Please clarify which class and rate applies to the $294,789 and revise the evidence as needed.

<u>Response:</u>

The CCA rate for the Omicron Injection Tester should be class 8 which is 20%. PUC has revised Appendix IR16 – PUCD – Bill C97 Accelerated CCA_20221128 and filed it with these responses as Appendix B in live excel format.

8-Staff-128

Ref 1: IRR 8-Staff-101
Ref 2: Tariff and Bill Impact Model, November 28, 2022, Tabs 3 and 5

Question:

OEB staff notes the following with respect to both versions of the Tariff and Bill Impact Model provided (i.e., with SSG and excluding SSG):

- Tab 3 requires updating for the most recent RPP rates, Pole Attachment Charge, Smart Metering Entity Charge and 2023 Retail Service Charges.
- Tab 5 requires updating to reflect the 2023 Retail service Charges as per reference 1
- Tab 6 shows an Ontario Electricity Rebate for the Street Lighting rate class of 17%. This should be updated to the current rate of 11.7%.

Please revise both versions of the Tariff and Bill Impact Model for these items.

Response:

PUC is unable to change the RPP rates, pole attachment charge and smart metering entity charge because the modelling sheet is locked. PUC applied the inflation factor of 3.30% to the Retail Service Charges to get the revised 2023 Retail Service Charges which did carry through to Tab 5. PUC is unable to update the OER credit for Street Light class as an error message is received when trying to save the file. The Street Light Class does not receive the OER benefit, therefore making this change would not impact the final bill impact model.

PUC is providing the proprietary table below on a preliminary basis and subject to change while the errors in the OEB model are being addressed.

Bill Impacts			Total Bill Impacts		Total Bill Impacts with SSG	
Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/Decrease	Total Bill Impact %	Total Bill Increase/Decrease	Total Bill Impact %
Residential	750	0	$5.46	4.52%	$3.88	3.22%
GS<50	2,000	0	$8.04	2.63%	$0.37	0.12%
GS>50	57,220	145	$106.30	1.23%	-$125.55	-1.46%
USL	3600	0	$28.87	5.03%	$13.04	2.27%
Sentinel Light	50	1.00	$8.15	16.18%	$7.65	15.18%
Street Light	199852	585	$3,985.03	9.23%	$3,269.40	7.92%

<u>9-Staff-129</u>

DVAs
Ref 1: 9-Staff -102
Ref 2: 9 -Staff-104

<u>Question:</u>

In Appendix IR18 of PUC Distribution's response to 9-Staff-102,

(a) Table 1-12 shows columns for RPP and Non-RPP. Please confirm that these columns should be for principal and interest, respectively. If not confirmed, please explain.
(b) Table 9-5 shows Account 1508, Sub-account Pole Attachment forecasted principal amounts to be up to December 31, 2021. Per 9-Staff-104, the sub-account has been forecasted to include activity up to the 2022 year-end. Please clarify.

<u>Response:</u>

(a) PUC has updated Table 1-12 and Exhibit 9 Tables as a result of revisions from these questions. Please refer to Appendix E.

(b) Table 9-5 should have been updated to forecast to April 30, 2023 as it included 2022 Pole variance and interest calculated to April 30, 2023.

9-Staff-130

DVAs
Ref 1: 9-VECC-54
Ref 2: IRR DVA Continuity Schedule

Question:

It states that PUC Distribution revised its Group 2 account claim in Tab 2b, rows 59 and 60 of the DVA Continuity Schedule.

(a) The claim amounts in row 59 and 60 in both the pre-filed and IRR DVA Continuity Schedules are $0. Please clarify what was updated.
(b) Please confirm that PUC Distribution is requesting final disposition of Group 1 balances. If not, please explain why not.
(c) The closing principal for 2021 (column BO) relating to the Substation16 sub-accounts were revised between the pre-filed and IRR versions of the DVA Continuity Schedule as shown in the following table.

	Pre-filed DVA Continuity Schedule ($)	IRR DVA Continuity Schedule ($)	Difference ($)
Substation 16 Depreciation	275,922	225,754	50,168
Substation 16 Accumulated Dep	- 275,922	- 225,754	- 50,168
Substation 16 Riders	- 629,377	- 611,290	- 18,087

Please explain the change in the account balances.

i. Please explain whether the related accumulated depreciation for Substation as reflected in the DVA Continuity Schedule has been updated. If yes, please explain the update made. If no, please explain why not.

Response:

a) Please see the response to OEB Staff 120(c) which revises rows 57-60 and adds an additional row 67 to ensure the proper amount is disposed of for Group 2 balances related to account 1508 – ICM Substation 16.

b) PUC can confirm that it is requesting final disposition of Group 1 balances.

c) The $50,168 in depreciation and accumulated depreciation is from the first 4 months of 2023. PUC has revised its DVA continuity schedule to exclude this amount as it will not be recorded in account 1508 and therefore should not form part of the balance. The substation 16 rate riders have further been revised to $632,807 as provided in response to OEB Staff-120. The reason for the further revision is the amount of rate riders collected are changing on a regular basis. PUC identified an error in its previous forecast and has revised it.

<u>9-Staff-131</u>

Pole Attachment Variance
Ref: IRR 9-Staff-104

<u>Question:</u>

Reference 1 notes that the Pole Attachment charge was $22.35 up to August 2021, $28.09 between September to December 2018, $43.63 effective January 2019, $44.5 effective January 2020, and $34.76 effective January 2022.

Please provide the calculation of the $69,334 requested for disposition, showing the Pole Attachment charges and the joint poles figures used.

<u>Response:</u>

PUC had an over collection in 2018 of $25,567 and an under collection in 2022 of $93,876. This results in a collection from customers of $68,309 and $69,334 when considering carrying charges. Please see the chart below.

	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec 31/21	Dec 31/22	Apr 30/23
Pole Att Rev Variance	-$25,567	-$25,567	-$25,567	-$25,567	$68,309	$68,309
Pole Att Rev Variance C/C	-$139	-$713	-$1,019	-$1,165	$143	$1,025
	-$25,706	**-$26,281**	**-$26,587**	**-$26,732**	**$68,452**	**$69,334**

9-Staff-132

COVID-19 Incremental Expense Variance
Ref: IRR 9-VECC-53b

Question:

Please provide a breakdown of the $250,166 incremental labour costs noted in the Reference by job classification and by year.

Response:

The following table provides the incremental labour costs by job classification and by year:

PUC Services Inc. Personnel	Job Class	2020	2021	Total
Executive	Executive	$ 26,654	$ 2,680	$ 29,334
Communications Coordinator	Manager	$ -	$ 1,226	$ 1,226
Manager - Billing & Special Projects	Manager	$ 53,846	$ 5,619	$ 59,464
Manager - Corporate Communications	Manager	$ 5,863	$ -	$ 5,863
Director, Finance	Director	$ 11,910	$ 5,955	$ 17,864
Assistant Controller	Manager	$ 40,191	$ 14,542	$ 54,733
Manager - Customer Care	Manager	$ 7,727	$ 2,208	$ 9,934
Customer Care staff	Staff	$ 53,737	$ 18,009	$ 71,747
		$ 199,927	$ 50,238	$ 250,166

9-Staff-133

Account 1589 & GA Analysis Work Form
Ref 1: 9-Staff-108
Ref 2: 9-Satff 109
Ref 3: DVA Continuity Schedule, Tab 2a
Ref 4: GA Analysis Workform

Question:

a) Reference 1 states that "In PUC Distribution's 11 2022 GA Analysis Workform, there were principal adjustments of ($759,501) and $759,201 for Accounts 1589 and 1588, respectively, that were recorded in the 2021 general ledger." and "The activity shown in Net Change did not include the 2020 adjustment. The GA Workform has now been updated to show the amount in the activity and the reversal."
   i) The principal adjustments in the DVA Continuity Schedule should agree to the total principal adjustments in the Principal Adjustment tab of the GA Analysis Workform. Please update the principal adjustments in the DVA Continuity Schedule to include $(759,501) and $759,501 for Accounts 1589 and 1588, respectively, in Reference 3 (Cell BF 31 & BF32).
   ii) Please confirm the balances for Account 1589 and 1588 are $709,967.23 and $(1,971,801.14), respectively, in Reference 3 (Cell BT32 & BT31). If not confirmed, please explain why.
b) Principal Adjustment in Reference 4 Tab 1588 (Cell D20) does not agree to the Principal Adjustment in Reference 4 Tab Principal Adjustment (Cell V63).
   i) Please reconcile the difference and update the two Tabs mentioned above.
   ii) Please confirm the Account 1588 % of Account 4705 in Reference 4 Tab Account 1588 (Cell G20) is -1.8% if including the $1,002,372 RPP related reconciling item, or -0.2% if excluding the $1,002,372 RPP related reconciling item. If not confirmed, please explain why.
c) Net Change in Principal Balance in the GL In Reference 4 Tab GA 2021 (Cell C75) does not agree to the Transactions Debit/(Credit) during 2021 in Reference 3 (Cell BD32).
   i) Please reconcile the difference and update the two Tabs mentioned above.
   ii) Please reassess the Unresolved Difference as % of Expected GA Payments to IESO in Reference 4 Tab GA 2021 Cell C93), if the percentage is greater than 1% if updated.

Response:

a) i) The adjustments have been added to the DVA Continuity Schedule, but to agree to the 2021 general ledger, they have also been added to 2021 transactions (Cell BD31 and BD32).

ii) As noted above, the $759,501 adjustments recorded in 2021 for 2020 activity were not included in the 2021 transactions (cell BD31 and BD32). Amounts have now been updated to agree to the GA Analysis. Balances in 1588 and 1589 remain at $1,187,958.07 and $73,874.57 respectively.

b) i) The GA Workform Cell C20 has been updated.

ii) Confirmed.

c) i) Amount has been reconciled.

ii) Due to the prior period adjustment of the of the IESO CT2148, the variance percentage is 1.8%. Without this adjustment, the current activity variance for the 2021 year is less than 1%.

School Energy Coalition (SEC)

SEC – 1

Reference: SEC 6

Question:

Please provide a copy of the referenced PUC Services corporate scorecard for each year since 2018.

Response:

PUC Service Inc. is a competitive affiliate of the applicant. Its corporate scorecard is strictly confidential and contains information that is not relevant to the matters at issue in this application.

SEC – 2

Reference: Ex.2, p.86-87

Question:

Please explain the basis for the CCA calculation in the revised ICM model shown at Table 2-20 and provide a comparison to that provided in the approved ICM model in EB-2020-0249. Please explain all differences besides that caused by the difference in total capital costs.

Response:

The change in CCA in table 2-30 on page 67 of Exhibit 2, for the SSG ICM, is due to a reduced spend in 2022 and timing of project completion. For example, all planned work in account 1920 computer software/hardware will be completed in 2023 which carries a CCA rate of 100%.

SEC – 3

Reference: Staff-32

Question:

Please provide a copy of the referenced integrated resources plan used to optimize spending over the 5-year DSP period.

Response:

The integrated resource plan referenced in Staff-32 is not a formal documented plan. During the preparation of the DSP, an evaluation of the impact on internal resources from all departments is completed to ensure that PUC can deliver on the annual forecast provided. These evaluations are then dynamic and continue to be re-evaluated through the years as information changes, such as the level of customer demand, and projects get completed to maximize resources efficiency.

SEC – 4

Reference: SEC 18

Question:

Please provide a response as requested. If PUC maintains its refusal, please explain with specificity, why the information is not readily available, and could not have been undertaken in the allotted interrogatory response time.

Response:

It is not clear that the probative value of the information resulting from a detailed accounting of the number of assets replaced (or planned to be replaced), many of which are below the materiality threshold, each year for 10 years outweighs the level of effort required. The requested information is also not an OEB requirement. Section 5.4 of PUC's DSP meets all of the requirements in Section 5.4.1 of the Chapter 5 Filing requirements, and particularly provides:

- An analysis of a PUC's capital expenditure performance for the DSP's historical period;
- An analysis of a distributor's capital expenditures for the DSP's forecast period; and
- An analysis of capital expenditures in the DSP's forecast period compared to the historical period.

This request would require an extensive number of hours to complete. Looking at 2023 alone, there are 23 line items listed as Forecast Net System Renewal Expenditures in Table 5.4-11 of the DSP for 2023, many of which are below PUC's materiality threshold. There are a number of projects subsumed within the 23 line items that would need to be individually reviewed to gather the requested information. When the number of line items and projects in the line items are extrapolated between 2018 and 2027, PUC would be reviewing a large number of records and historical individual work orders covering each subject year to fulfill the request of this IR. PUC would then need to extract the relevant information from each record and aggregate it into a presentable format. Typically to ensure data quality, this data would then be audited by a reviewer to ensure no errors are made. Expecting PUC to perform this task in the allotted time is not reasonable, especially since PUC had to respond to approximately 567 interrogatories in the 3-week interrogatory response time. PUC notes that some of the information requested may be included in the material investment summaries of the DSP.

SEC – 5

Reference: SEC 20

Question:

SEC requested PUC to provide ‘Material Investment Narratives’ documents for capital projects/programs completed during the last rebasing period that the company now seeks to add to rate base. Implicit in the response is that such document did not exist for previous capital work.

a. Please confirm that these documents do not existing for 2019 to 2022 capital projects/programs.

b. Does PUC have any documentation that is produced internally that documents material capital project/program prioritization, alternatives, costs, evaluation criteria, need, justification or similar information? If so, please provide details and copies as it relates to 2019-2022 material capital investments.

Response:

a) PUC did not prepare ‘Material Investment Narratives’ documents for capital projects/programs completed between 2019 and 2022 that the company now seeks to add to rate base. The requested information is not required under section 5.4.2.1 of the Filing Requirements.

b) A prioritization matrix was provided in the 2018-2022 Distribution System Plan for the test year in Table 23: Prioritization Matrix for Test Year Projects over Materiality Threshold. Beyond the test year, informal discussions and project reviews are dynamic. As project-specific details are reviewed, alternative options are considered, balancing the capital investment needed and the related new or replacement quantity of assets with the overall customer’s impact. PUC does not at this stage have any further additional relevant information to provide beyond what was issued to support the capital-related costs upon which its rate proposal is based, as required under section 5.4.2 of the Filing Requirements.

SEC – 6

Reference: Staff-89e, SEC-34

Question:

Please provide the calculation based on actual capital additions in each year (2019-2022) and provide supporting calculations similar to that provided in PUC_IRR_Appendix IR16_PUCD_Bill C97 Accelerated CCA_20221128.

Response:

PUC has provided the updated calculations requested in Appendix C Appendix IR16 - PUCD - Bill C97 Accelerated CCA_20221128_SEC6. This update is included on the tab 2018-2022. Please note that the actual capital additions were used in each year 2019-2022 when calculating accelerated CCA. The 2018 additions were still used in calculating CCA at the old rate.

SEC – 7

Reference: Staff-96

Question:

Please confirm that the calculation of the variable charge provided in the response is based on the as-filed application proposed revenue requirement, as opposed to the updated revenue requirement included with the interrogatory responses. If confirmed, please provide a revised response based on the updated revenue requirement included with the interrogatory responses.

Response:

PUC can confirm that the response provided in Staff 96 is based on the revenue requirement as filed on August 31, 2022.

PUC has revised the table and reproduced below based on the revised revenue requirement submitted with the Interrogatory Responses November 28, 2022:

	Fixed	Variable
GS<50	$22.32	$0.0382
GS>50	$123.27	$9.6625
USL	$13.67	$0.0550

SEC – 8

Reference: Ex 2, Appendix B With respect to the VVO Link to ROE calculation:

Question:

a. [p.3] The Draft AO states the following: "Considering that the COP will fluctuate on a yearly basis, PUC proposes a band where the breakeven point, (i.e., $0 savings to customers) as a percentage is the low end of the band, with the upper limit being 2.70% or $234,177 VVO savings" [emphasis added]. Is the upper limit 2.70% energy savings or $234,177 in net savings to customers.

b. [p.3] The Draft AO states the following: "The final step is to review the revenue requirement calculation for SSG included in rates. The benefit of reduced future capital expenditures, as described in EB-208-0219/2020-0249 is $234,177 in each year moving forward." Please confirm reference to $234,177 in this sentence is an error and should be $304,389.

c. Please confirm the $304,390 'benefit of reduced capital expenditure' line item is a capital expenditure number whereas the 'additional revenue from increased SSG asset base' line item is a revenue requirement number.

Response:

a) The upper limit is 2.70% VVO Savings.

b) Confirmed.

c) The $304,390 benefit of reduced capital expenditure is a revenue requirement number.

SEC – 9

Reference: Staff 27-d

Question:

The interrogatory asked PUC to update the VVO Link to ROE calculation with the 2023 cost of capital parameters. In response, PUC updated Table 5.3-29.

a. Please confirm the 2.36% consumption savings used in the table was premised on the that being the point in which, on all else being equal, results in $0 net benefit to customers.

b. Based on the revise table, the deadband is now $2,974 (top) and -$230,203 (bottom) in annual net benefits to customers. Please confirm this is correct and confirm?

c. Is PUC proposal to update the calculation for the revise 2023 cost of capital parameters and if is the deadband that set out in question part (b)?

d. Please provide a breakdown of the updated 'additional revenue from increased SSG asset base' calculation.

Response:

a) Confirmed.

b) Confirmed. The dead band dollar value has shifted; however, the dead band VVO percentage amount still remains at 2.36% to 2.70%.

c) PUC developed this calculation during the preparation of its cost of service application and locked in the dead band of 2.36% to 2.70%. PUC's proposal is to keep that dead band regardless of the other inputs into the model which are outside of PUC's control and evolving on a regular basis (i.e. Cost of Power, Revenue Requirement, Interest Rates, etc.).

d) PUC provided a side by side calculation of this in its Interrogatory Responses as Appendix IR1 – Additional revenue from increase SSG asset base.

SEC – 10

Reference: Appendix H – PUC's Response to OEB Order #6, Appendix B

Question:

Please provide a copy of IEEE 1885-2022

Response:

IEEE 1885-2022 is available for purchase here: https://standards.ieee.org/ieee/1885/5624/.

Vulnerable Energy Consumers Coalition (VECC)

VECC-55

REFERENCE:

Staff 54 b) and VECC 22
Staff 1: PUC_2023_Load Forecast – With Regression Analysis_20221128

PREAMBLE:

The responses to both Staff 54 b) and VECC 22 a) indicate that customer count should not be included in the regression model used to forecast purchased power. However, the updated Load Forecast model referenced in Staff 1 still includes customer count as an explanatory variable.

Question:

a) Please confirm that PUC's proposal is to exclude customer count as an explanatory variable.

b) If confirmed, please provide a version of the Load Forecast model that reflects all of the revisions PUC is proposing be made to the model as originally filed.

Response:

a) Confirmed.

b) PUC has revised the Load Forecast model to remove the customer count as an explanatory variable. The CDM adjustment has also been revised in accordance with the response in VECC-56.

VECC-56

REFERENCE:

VECC 24

Question:

a) The calculation of the manual CDM adjustment increases PUC's share of the conservation savings forecasted by the IESO by 4.62%. Please set out PUC's understanding of where on the electricity system (e.g., customer delivery point, point of generation, or some other point) the conservation savings forecast by the IESO are "measured" and provide references supporting this view.

b) Base on the response to part (a) please explain why it is appropriate to mark the savings up a factor that represents distribution losses.

Response:

a) The calculation of the manual CDM adjustment increases PUC's share of the conservation savings forecasted by the IESO by 1.0462%, not 4.62%.

   CDM has historically been measured at the customer level. The Minister's Directive of September 30, 2020 provides the most recent definition of CDM: "The IESO shall consider CDM to be inclusive of activities aimed at reducing peak electricity demand and/or electricity consumption from the electricity system. Examples of CDM include energy efficiency replacements whereby similar output is achieved with less electricity, and behind-the-meter consumer generation." Further, the *2021-2024 Conservation and Demand Management Program Plan, January 4, 2021* states that savings are calculated in accordance with the IESO *Evaluation, Measurement and Verification Protocol* , p.31 of which describes how data are to be collected: either through a deemed savings approach, or a custom M&V approach **measured on-site**.

b) The CDM savings also results in savings in distribution losses. On reviewing where the CDM adjustment is being made in the load forecast, PUC has concluded that the CDM adjustment is being made to the forecast load *before* the loss factor is applied so the CDM adjustment should not include distribution losses. The factor for distribution losses has been removed from the CDM adjustment in the load forecast.

VECC-57

REFERENCE:

Staff 1: PUC_2023_Filing_Requirements_Chapter2_Appendices_20221128, Tab 2 H
VECC 39 a)

Question:

a) Please provide a detailed breakdown of the updated revenues for account #4210.
b) Please provide a schedule that sets out the calculation of the 2023 Building Charges revenue of $1,035,470 per the original Application and the changes made to derive the revised value included in the IRR update.

Response:

a) The updated revenues for account 4210 are from a change in the pole attachment rate used and the 2023 building return charges. Please refer to the answer in part (b) for the detailed calculation of the building return charge. For the Pole attachment revenue, PUC identified a calculation error in the rate used in the IRs. Please see the below table that reconciles the calculations used for pole attachment rates:

Date	Total Poles	Rate used	Total Poles Revenue 4210
31-Aug-22	19375	34.76	673,475
28-Nov-22	19375	37.06	718,038
12-Dec-22	19375	36.05	698,469

b) Please see the table below for a side-by-side comparison. The changes from August 31, 2022 to November 28, 2022 include Updated Cost of Capital Parameters and the reclassification of Omicron Injection tool.

			2023 (Aug 31, 2022)	2023 (Nov 28, 2022)
Deemed Short-Term Debt			1.17%	4.79%
Deemed Long-Term Debt			3.76%	4.88%
Return on Rate Base -Equity			8.66%	9.36%

Current Revenue Requirement			2023	2023
Opening Cost			25,959,603	25,959,603
Gross Capital Additions			$ 577,035	$ 282,246
Accumulated Depreciation			$ 6,888,803	$ 6,888,803
Net Book Value			$ 19,647,835	$ 19,353,046

M Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base				
Incremental Capital			$ 19,647,835	$ 19,353,046
Depreciation Expense (prorated to Eligible Incremental Capital)			$ 731,555	$ 725,659
Incremental Capital to be included in Rate Base (average NBV in year)			$ 19,282,058	$ 18,990,217
	% of capital structure			
Deemed Short-Term Debt		E	$ 225,600	$ 909,631
Deemed Long-Term Debt		F	$ 724,066	$ 926,723
	Rate (%)			
Short-Term Interest	4.00%	I	$ 9,024	$ 36,385
Long-Term Interest	56.00%	J	$ 405,477	$ 518,965
Return on Rate Base - Interest			$ 414,501	$ 555,350
	% of capital structure			
Deemed Equity %	40.00%	N	$ 7,712,823	$ 7,596,087
	Rate (%)			
Return on Rate Base -Equity		O	$ 667,930	$ 710,994
Return on Rate Base - Total			$ 1,082,431	$ 1,266,344

Amortization Expense				
Amortization Expense - Incremental		C	$ 731,555	$ 725,659

Grossed up Taxes/PILs				
Regulatory Taxable Income		O	$ 667,930	$ 710,994
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$ 731,555	$ 725,659
Deduct CCA (Prorated to Eligible Incremental Capital)			$ -	$ -
Incremental Taxable Income			$ 1,399,485	$ 1,436,653
Current Tax Rate	26.5%	X		
Taxes/PILs Before Gross Up			$ 370,864	$ 380,713
Grossed-Up Taxes/PILs			$ 504,576	$ 517,977

Incremental Revenue Requirement			2023	2023
Return on Rate Base - Total		Q	$ 1,082,431	$ 1,266,344
Amortization Expense - Total		S	$ 731,555	$ 725,659
Grossed-Up Taxes/PILs		Z	$ 504,576	$ 517,977
Incremental Revenue Requirement			$ 2,318,562	$ 2,509,979

Revenue Offset Calculation			2023	2023
Retained by Distribution			$ 1,283,092	$ 1,389,023
Water			$ 856,245	$ 926,935
Services			$ 179,225	$ 194,021
Total Revenue Offset			**$ 1,035,470**	**$ 1,120,957**

VECC-58

REFERENCE:

VECC 41 a)

Question:

a) Please explain why the cost per connection for Residential underground service ($3,220) is significantly higher than the cost per connection for GS<50 or GS>50 underground service ($456).

Response:

The ownership demarcation points of customer classes differ from one to another. The ownership demarcation point for the above noted customer classes are summarized in the below table:

Customer Class	Connection Type	Ownership Demarcation Point
Residential Secondary Service	Underground Service	Line side of exterior meter socket or main switch or current transformer
General Secondary Service	Underground Service	Secondary connections at load side of PUC transformer
General Primary Service	Underground Service	Secondary connections at load side of PUC transformer (Section 3.0.3 – Where primary service is required, the Customer will be responsible for all costs to construct a private pole line or underground duct bank structures.)

Costs for residential secondary services are higher than connections for GS<50 and GS>50 due to PUC owning the secondary service inclusive of the trenching, conduits, and cables for residential secondary services. This differs from GS connections as the customer is responsible for the cost of the services and therefore PUC's contribution is limited to connections.

For further clarity on demarcation points, please refer to PUC's Conditions of Service, Appendix C: Demarcation Points and Connection Charges Application.

VECC-59

REFERENCE:

PUC_2023_Tariff_Schedule_and_Bill_Impact_Model_20221128

Question:

a) In the Residential Bill Impact model, the 2023 volumes used for RTSR, WMS and RPP are hard coded at 763 kWh – what is the basis for this value and is this the value that will be used in 2023 for billing a customer with 750 kWh of usage?

b) In the Residential Bill Impact model, the 2023 volumes used for Commodity (total), Total Deferral/Variance Account Rate Riders, CBR Class B Rate Riders and Additional Volumetric Rate Riders are hard coded at roughly 730 kWh –what is the basis for this value and is this the value that will be used in 2023 for billing a customer with 750 kWh of usage?

Response:

Response to “a” and “b”:

The final tab of the Tariff Schedule and Bill Impact Model was unlocked so that PUC could ‘hard-code’ the proper consumption amounts to show the bill impacts including VVO savings of 2.70%. The Current OEB-Approved Column uses a consumption of 750 kWh, and the Proposed column uses a consumption of 750kWH less 2.70% VVO savings or 730 kWh. This calculation is applied through all the rate classes and accounts for the difference you see in consumption from the Current OEB-approved column to the Proposed column. The 730kWh is the revised consumption that a customer will be using once they receive the 2.70% VVO consumption savings. A customer who was once using 750 kWh in 2022 will now be consuming 730 kWh in 2023, all else remaining equal.

Consumers Council of Canada (CCC)

CCC-49

REFERENCE:

Re: CCC-18

Question:

In 2023-2027 the plan adds EV each year based on supply chain availability. PUC expects 4 EV purchases in 2023.

Please provide the budget line item and amount for EV purchases in 2023.

Response:

To clarify, it is PUC Services Inc. that expects to have 4 EV purchases in 2023.

CCC-50

REFERENCE:

Re: CCC-22 (a)

Question:

PUC provides the annual vehicle leasing costs proposed in 2023 and references the guidelines in the Full Absorption Cost Allocation Review completed by BDR North America Inc.

Please provide the Shared Services Agreement between PUC and PUC Services.

Response:

PUC has provided the Shared Services Agreement as Appendix D – PUC Services Inc and PUC Distribution Inc Agreement.

CCC-51

REFERENCE:

Re: CCC-24

Question:

Please provide the circuit's historical failures during the last five years by year.

Response:

The table below shows the number of underground cable failures per year per circuit over the five years used in the ACA for the purpose of evaluating the health index.

Underground cable failures per circuit								
Circuit	2017	2018	2019	2020	2021	Total # of outages	Total UG Cable length (km)	Failure count per 10 km per year
21-02	3	3	4	2	1	13	14.34	2.01
20-04	1	1	2	2	0	6	9.55	1.40
12-14	1	2	1	2	0	6	6.26	2.13
13-01	2	0	0	0	0	2	3.96	1.12
1-12	1	4	0	0	0	5	0.02	483.91
11-13	1	0	2	0	0	3	0.50	13.22
21-01	4	1	1	0	0	6	5.06	2.64
18-04	1	0	1	0	0	2	4.21	1.06
20-01	1	0	0	0	0	1	1.19	1.86
TA-11	0	1	0	0	0	1	0.18	12.32
19-04	0	1	0	2	0	3	4.23	1.58
11-14	0	1	3	1	0	5	2.44	4.56
12-13	0	0	1	0	2	3	4.60	1.45
12-11	0	0	1	0	0	1	0.75	2.97
16-02	0	0	1	0	0	1	7.88	0.28
16-04	0	0	3	2	1	6	10.32	1.29
5-02	0	0	1	0	0	1	0.00	0.00
12-12	0	0	1	1	1	3	10.11	0.66
11-12	0	0	1	1	0	2	0.79	5.59
2-15	0	0	1	0	0	1	2.68	0.83
18-02	0	0	0	1	0	1	2.58	0.86
19-03	0	0	0	1	0	1	3.95	0.56
TA-6	0	0	0	5	0	5	2.67	4.16
13-04	0	0	0	1	0	1	0.52	4.31
2-14	0	0	0	0	3	3	3.79	1.76
11-11	0	0	0	0	1	1	1.90	1.17

CCC-52

REFERENCE:

Re: CCC-30

Question:

Please confirm receipt of the breaker for Substation 19.

Response:

PUC has not yet received the breaker for Substation 19.

CCC-53

REFERENCE:

Re: CCC-37 (a)

Question:

PUC indicates that added positions in support of SSG account for part of the increase in O&M in 2023 compared to 2021.

Please provide a summary of the number of FTEs added to support SSG by year including the position title and cost.

Response:

Please refer to OEB Staff-67 (reference: Exhibit 4, pg.8 and Exhibit 4, pg. 26).

CCC-54

REFERENCE:

Re: VECC-8

Question:

The response states "PUC directed approximately $3.5M of COS dollars to station renewal of assets that would benefit both the DSP ACA objectives and the SSG objectives. This investment was primarily for two transformers and a 34.5kV switchgear at Substation 20, and transformers at Substations 2 and 11. Due to NRCan grant funding received for the SSG project, the PUC will receive a 25% savings on that $3.5M dollar investment.

Please discuss if the $3.5M investment is included in the $28,713,347 for the SSG ICM project.

Response:

The $3.5M investment is not included in the $28.7M. Please refer to OEB Staff-115.

CCC-55

REFERENCE:

Re: OEB Staff – 25

Question:

The question asked for a cost variance breakdown for the SSG Project comparing the actual cost of the project components compared to what was planned. The answer states:

> As the project is still in progress and actual costs have not been fully incurred, it is still too early to provide a detailed breakdown of actual costs. These actual costs will be trued up-up and subject to OEB approval at a later date. To be of assistance, PUC can state that the project is currently trending on budget.

Please clarify what amounts PUC is seeking to add to ratebase for the SSG project in 2022 and 2023. When does PUC expect that these amounts will be trued up? Please indicate why PUC cannot provide a comparison as requested based on actual costs and the most recent forecast of expected costs?

Response:

PUC has provided an update to all models based on the revised spend which is estimated as follows:

	2022 (in millions)	2023 (in millions)
Gross	$12.0	$19.9
NRCan	$(3.0)	$(4.4)
Net	$9.0	$15.5

Delays impacting the project have been encountered in a number of areas but at a high level the largest contributing factor was the COVID pandemic and the ripple effect on availability of equipment, materials and resources.

In the early design stages the restrictions to border travel impacted the engineering teams ability to be on-site for design efforts. Remote work arounds were employed, but some time delays and turn around on reviews and comments were encountered. As construction got underway there were supply chain and vendor delays that impacted work sequencing. With the nature of the cascading station outage plan, equipment or material item delays caused schedule slip. The schedule changes also impacted planning on specialized resources for construction, testing and commissioning. Compounding the resource challenge was a very active local construction season and availability and scheduling of equipment, supplies such as concreate, and local work forces. As the schedule delays pushed the work into colder winter months, there were additional impacts to the ability to plan station outages due to higher system loads which also stretched the schedule

CCC-55

REFERENCE:

Re: OEB Staff – 25

and continues to be the case in the first quarter of 2023.

Based on current forecasts, the physical installation of the SSG Project will be largely complete by March 31. However, Substantial Completion will not occur until November 1, 2023.

Substantial completion is a defined term under the EPC Contract with Black & Veatch (see Amended Application at Appendix AA3-7 from EB-2020-0249/EB-2018-0219). As set out in the response to Staff-18, Substantial Completion generally requires optimization and testing by Black and Veatch: (a) on a station by station basis to finalize voltage reduction settings and control systems; and (b) on full system wide basis to confirm coordinated station performance, which includes items such as integrated measurement, verification and reporting. As set out in the response to Staff-29, the testing and optimization phase of the SSG Project was always expected to occur subsequent to the physical installation of the SSG Project. PUC anticipates to be in a position to start measuring VVO savings at the time of Substantial Completion.

CCC-56

REFERENCE:

Re: OEB Staff – 70

Question:

The variance between the test year (2023) Administrative Costs and the 2018 OEB approved amounts represents an increase of approximately $934,000. Part of the variance can be attributed 5 to additional positions. How much of the variance is attributable to those positions? What is the other part attributable to?

Response:

The variance attributable to the positions is approximately $354k. The other part of the variance is attributable to inflationary increases as well as other labour increases, software, and the Shared Services allocation costs.

CCC-57

REFERENCE:

Re: CCC-3

Question:

Please describe the ownership structure of 17 Trees. Please provide all contractual arrangements between 17 Trees and PUC Distribution Inc.

Response:

The shares of 17 Trees Inc. are 1/3 owned by PUC Inc., PUC's sole shareholder. The other 2/3 of the shares are split evenly between Greater Sudbury Utilities Inc. and North Bay Hydro Services Inc. The 17 Trees Inc. PO is provided at Appendix F. Presumptively confidential information under Appendix B of the Practice Direction on Confidential Filings, namely unit pricing and billing rates, has been redacted.

Appendix A – RFP No 22 04 06 Green Button Implementation

REQUEST FOR PROPOSAL

(RFP)

GREEN BUTTON IMPLEMENTATION

CONTRACT NO. 22 04 006

Important Dates

The following is a tentative schedule that will apply to this RFP but may change in accordance with the organization's needs or unforeseen circumstances. Changes will be communicated by e-mail to all proponents.

Issue Date of RFP	**May 2, 2022**
Deadline for Vendor Questions	**May 11, 2022: 12:00pm**
Anticipated Deadline for Issuing Addenda	**May 17, 2022**
Requested Proposal Submission Date	**May 25, 2022: 4:00pm**
Review of Submitted Proposals	**June 3, 2022**
Presentations	**June 8 and 10, 2022**
Overall Review of Shortlist Proposals	**June 17, 2022**
Anticipated Selection of Vendor	**June 17, 2022**
Contract Negotiations	**June 24, 2022**

TABLE OF CONTENTS

PART 1: INTRODUCTION

1.1 Invitation to Proponents

This Request for Proposal (RFP) is issued by PUC Services Inc., hereafter referred to as "PUC", as an invitation to prospective Proponents to submit proposals for the provision, implementation, and on-going support of Green Button (collectively, the "Deliverables") to PUC.

1.2 The Organization

PUC is a group of companies that operates multiple utilities and within Ontario, including the supply, treatment and distribution of municipal drinking water, the supply of electricity, and the operation of wastewater treatment facilities.

1.3 Type of Contract for Deliverables

The intended coverage of this RFP is per Part 3 of this document.

Although it is PUC's intention to enter into the agreement with only one (1) legal entity, PUC makes no guarantee of the value or volume of work to be assigned to the successful Proponent.

PUC makes no representation, warranty or guarantee as to the accuracy of the information contained in the RFP. Any quantities shown or data contained in this RFP are estimates only and are for the sole purpose of indicating to Proponents the general size of the work.

1.4 Proponents Understanding of RFP

In responding to this RFP, the Proponent accepts full responsibility to understand the RFP in its entirety, and in detail, including making any inquiries to PUC as necessary to gain such understanding. PUC reserves the right to disqualify any Proponent who demonstrates less than such understanding. Further, PUC reserves the right to determine, at its sole discretion, whether the Proponent has demonstrated such understanding. That right extends to cancellation of award if award has been made. Such disqualification and/or cancellation shall be at no fault, cost, or liability whatsoever to PUC.

1.5 Good Faith Statement

All information provided by PUC in this RFP is offered in good faith. Individual items are subject to change at any time. PUC makes no certification that any item is without error. PUC is not responsible or liable for any use of the information or for any claims asserted there from.

1.6 Communication

Verbal communication shall not be effective unless formally confirmed in writing by a specified procurement official in charge of managing this RFP process. In no case shall verbal communication govern over written communication.

1.6.1 Proponent's Inquiries

Applicable terms and conditions herein shall govern communications and inquiries between PUC and Proponents as they relate to this RFP. Inquiries, questions, and requests for clarification related to this RFP are to be directed in writing to:

PUC Services Inc.
500 Second Line East
Sault Ste. Marie, ON P6A 4K1
Attention: Shelley Hambly, CSCMP
Email: purchasing.dept@ssmpuc.com

1.6.2 Informal Communications

Informal communications shall include, but are not limited to requests from/to Proponents or Proponents' representatives in any kind of capacity, to/from any PUC employee or representative of any kind or capacity except for **Shelley Hambly** for information, comments, speculation, etc. Inquiries for clarifications and information that will not require addenda may be submitted verbally to the named above at any time.

1.6.3 Formal Communications

Formal Communications shall include, but are not limited to:

- Questions concerning this RFP must be submitted in writing and be received prior to **May 11, 2022: 12:00pm.**
- Errors and omissions in this RFP and enhancements: Proponents shall recommend to PUC any discrepancies, errors, or omissions that may exist within this RFP. With respect to this RFP, Proponents shall recommend to PUC any enhancements, which might be in PUC's best interest. These must be submitted in writing and be received prior to **May 11, 2022: 12:00pm.**
- Inquiries about technical interpretations must be submitted in writing and be received prior to **May 11, 2022: 12:00pm**. Inquiries for clarifications/information that will not require addenda may be submitted verbally to the named above at any time during this process.
- Verbal and/or written presentations and pre-award negotiations under this RFP.
- Addenda to this RFP.

1.6.4 Addenda

PUC will make a good-faith effort to provide a written response to each question or request for clarification that requires addenda within four (4) business days. All questions, answers, and addenda will be shared with all proponents.

PUC will not respond to any questions or requests for clarification that require addenda, if received after **May 11, 2022: 12:00pm.**

PART 2: TERMS & CONDITIONS

2.1 Rights of PUC

2.1.1 PUC's Right to Amend, Supplement or Cancel the RFP

PUC without liability, cost, or penalty, may in its sole discretion:

(a) Alter any dates in the RFP, as they relate to the RFP Process, at any time prior to or after the Closing Date and Time.

(b) Cancel this RFP at any time, whether prior to or after the Closing Date and Time, and PUC may, but need not, in its sole discretion, issue a new RFP.

(c) Amend or supplement this RFP at any time prior to the Closing Date and Time.

2.1.2 Proposal Acceptance and Significance of the Proposed Price Process

PUC will not necessarily accept the lowest priced Proposal or any Proposal. While price is an element in the selection process, Proponents should recognize that there are other criteria in this RFP that PUC will consider in evaluating Proposals and in making its decision as to the award of a contract.

As it is the intention of PUC to award to that Proponent (if any) who offers the best over-all value to PUC, PUC reserves the right in its sole discretion to accept or reject any bid which in the opinion of the PUC is incomplete, obscure, irregular, contains exceptions or counteroffers, or which is non-compliant with the terms of the Proposal.

2.1.3 PUC's Right to Waive Irregularities

PUC, without liability, cost, or penalty, may, in its sole discretion, waive irregularities in Proposals or in the submission of Proposals.

2.1.4 PUC's Right to Clarify Proposals

PUC, without liability, cost, or penalty, may, in its sole discretion and at any time after Proposal submission, seek clarification from any Proponent, either in writing or during a Presentation with respect to its Proposal. Without limiting the generality of the foregoing, PUC may, in its sole discretion, request a Proponent to confirm in writing any statement made by the Proponent during the Presentation stage in which case the Proponent will promptly provide such written confirmation to PUC, within the time specified.

Any written information received by PUC from a Proponent in response to a request for clarification from PUC shall be considered as an integral part of the Proponent's Proposal.

Without prejudice to this right, PUC may request clarification where any Proponent's intent is unclear, or PUC may waive or request amendments where, in the opinion of PUC, there is an irregularity or omission in the information submitted in the Proposal.

2.1.5 PUC's Right to Verify

PUC may verify any Proponent's statement or claim by whatever means PUC deems appropriate, including contacting references other than those offered by the Proponent. PUC may reject any Proponent statement or claim if, in the judgment of PUC, the statement or claim is unwarranted or not credible. The Proponent shall co-operate with PUC in its attempts to verify any such statement or claim.

2.1.6 PUC's Right to Waive Mandatory Requirements

Wherever the words "will", "shall", or "must" are used in this RFP, PUC will have the option of waiving this as a mandatory requirement as it is intended that Proposals be subject to review and negotiations and not all options may be known to PUC at this time, which is why it is looking for innovative Proposals from experienced Proponents. Therefore, PUC must have the ability to waive what would otherwise appear to be mandatory requirements in the appropriate situation as determined by PUC.

2.2 Right to Amendments or Withdrawal of Proposal by Proponent

A Proponent that submits a Proposal to PUC may amend its Proposal only by submitting an amended proposal to PUC at the location identified before the closing date and time. The latest Proposal received by PUC from a Proponent, before the closing date and time, shall supersede and invalidate any Proposal previously submitted by that Proponent.

A Proponent that submits a Proposal to PUC may withdraw its Proposal by advising the RFP Contact, as described in Part 1 Section 1.6.1, in writing before the Closing Date and Time.

2.3 Disqualification of Proposals on Grounds of Faulty Submission

PUC, without liability, cost, or penalty, in its sole discretion, may disqualify any Proposal at any time during the RFP process if, in the opinion of PUC, one or more of the following events occur:

(a) The RFP contains incorrect information that is fundamental to the submission.

(b) The Proponent is unresponsive to this RFP.

(c) The Proponent fails to cooperate with PUC in its attempts to clarify information or evaluate the Proposal.

(d) The Proponent misrepresents any information provided in its Proposal.

(e) The Proposal is incomplete.

(f) The Proposal, on its face, reveals a conflict of interest or unfair advantage; or

(g) A change has occurred in the management or ownership structure of the Proponent's organization.

2.4 Costs Incurred by Proponents

Nothing in this RFP, receipt by PUC of a response to this RFP, or subsequent negotiations by PUC of terms of a contract, shall in any way impose an obligation on PUC to reimburse any Proponent or to pay any compensation for costs incurred in the preparation of a response to this RFP, presentations, or the negotiation of a proposed contract.

2.5 Privilege Clause

Nothing in this RFP, receipt by PUC of a response to this RFP, or subsequent negotiations by PUC of terms of a contract, shall in any way impose a legal obligation on PUC to sign a contract with any Proponent.

Bidders are notified that the lowest or any proposal need not be accepted by PUC and PUC reserves the right to reject all proposals at any time without further explanation or to accept any proposal considered advantageous to PUC. Proposals which contain qualifying conditions or otherwise fail to conform to these RFP documents may be disqualified or rejected. PUC may waive any non-compliance with the Proposal documents, specifications, or any conditions, including the timing of delivering of anything required by this RFP and may at its sole discretion elect to retain for consideration Proposals which are non-conforming because they do not contain the content or form required by the RFP documents or because they have not complied with the Process for submissions set out herein.

2.6 Contract Award

2.6.1 The Contract

PUC's right to accept any bid and reject any bid or all bids.

Any contract award made pursuant to this RFP is conditional upon the Selected Proponent entering into a contract with PUC under the terms and conditions of this tender.

2.6.2 Signing the Contract

PUC shall advise the Selected Proponent once ready to commence negotiations. The negotiations shall be concluded within a timeframe mandated by PUC, acting reasonably. The Selected Proponent shall prepare and provide to PUC a Services Agreement with two executed copies.

2.6.3 Omissions and Discrepancies

Should a Proponent find discrepancies in or omissions or Contract documents or should be in doubt as to their meaning, they should notify PUC's Contact.

2.7 Proponent's Failure to Sign the Contract

2.7.1 Situations

One or more of the following situations occur, PUC may invoke one of the following options stated in Clause 2.7.2:

(a) The negotiations with the Selected Proponent are not successful and PUC, in its sole discretion, does not think that a contract satisfactory to PUC can be reached.

(b) The Selected Proponent fails to employ best efforts to finalize a contract during the timeframe mandated by PUC; or

(c) The Selected Proponent fails or refuses to enter a contract within the timeframe mandated by PUC.

2.7.2 Options

In the case of PUC and the Selected Proponent not being able to come to an amicable contract agreement, PUC without liability, cost, or penalty, may, in its sole discretion:

(a) Extend the period for negotiation or execution; or

(b) Cease negotiations with the Selected Proponent; or

(c) Enter negotiations with the second highest rated proponent; or

(d) Exercise PUC's rights pursuant to Sub-Section 2.1.1(b) to cancel the RFP.

2.8 Limitation of Liability

Each Proponent, by submitting a Proposal, agrees that in the event that any or all of the Proposals are rejected or disqualified, or the Project or selection process is modified, suspended or cancelled for any reason, PUC is found to be in breach of its obligations under this RFP, including due to its fault or negligence, has otherwise failed to follow any Process required under the terms of this RFP, neither PUC, nor its employees, advisors or representatives will be liable under any circumstances for any claim or to reimburse or compensate any person or entity in any manner whatsoever for loss of anticipated profits, loss of opportunity, or any indirect or consequential damages and the Proponent waives any claim for loss of profits or loss of opportunity, indirect or consequential damages, if the Proponent is rejected or disqualified, or is not successful in the selection process for any reason whatsoever. The Proponents acknowledge in evaluating the Proposals, PUC and its advisors are seeking a Proposal satisfactory to PUC's needs and are under no duty to the Proponents except to bona fide consider all Proposals and that this RFP is not a contract between PUC and the Proponents.

2.9 Litigation

If PUC or any of its officers, employees, assigns, independent contractors, subcontractors, agents or representatives are made a party to any litigation arising out of or by reason of or attributable to this RFP, then the applicable Proponent(s) shall indemnify and save harmless PUC and its officers, employees, assigns, independent contractors, subcontractors, agents or representatives in connection with such litigation, except to the extent that such litigation arose from the negligence or willful act of PUC, or any of its officers, employees, assigns, independent contractors, subcontractors, agents or representatives.

2.10 Performance of Work

The Proponent shall, before submitting their Proposal, satisfy themselves as to the local conditions that may be encountered during services of the work. They shall make their own estimate of the services and difficulties that may be encountered and the nature of the subsurface materials and conditions. The Proponent shall not claim at any time after submission of their Proposal that there was any misunderstanding of the terms and conditions of the Contract relating to site.

The Proponent shall complete the work in a reasonable time frame, recognizing that total anticipated quantities during the term of the contract will require an ongoing commitment of resources by the Proponent throughout the service period. The Proponent shall make every effort reasonable to complete the work expeditiously as it is issued.

2.11 Inspection of Work

It shall be the responsibility of the Proponent to review their work before declaring an item is completed. The review by the PUC 's Contact shall take place prior to the issue of payment and be an agenda item at the regular project meetings.

The Proponent shall supply proof of required certificates, competencies and required training to successfully complete the work. Furthermore, these requirements must be kept current during the duration of the Contract.

2.12 Notice

All Notices under this Agreement shall be in writing and shall be deemed received, if properly sent to the addresses as listed in Part 1 Section 1.6.1.

2.13 Right to Negotiate

Should PUC not receive any satisfactory bid, in its sole discretion, PUC reserves the right to negotiate a contract for the whole or part of the Proposal with any one or more of the Proponents without becoming obligated to offer to negotiate with all Proponents.

2.14 Power to Pause

In the event PUC discovers the Proponents have received unequal access to relevant information regarding the requirements of the RFP, PUC reserves the right in its sole discretion to suspend the competitive bid process, issue new information in writing to all Proponents and then continue the competitive bid process.

In the event PUC chooses to suspend the procurement process, those Proponents who have submitted Proposals will be provided with new information and allowed an additional five (5) business days to change their Proposals should they choose to do so or to withdraw altogether.

Thereafter, PUC will continue the competitive bid process with the then remaining Proponents, with all other requirements of the instructions to Proponents applying as if the competitive bid process had not been suspended.

2.15 Confidentiality

The RFP is strictly confidential and proprietary to PUC. Proponents will not use the information included in the RFP without prior written consent from PUC. In addition, information in the RFP will not be shared with any other Proponent. A final decision will be made strictly on the merits of the submitted documents. The decision of PUC is final.

2.16 Term of Contract

The initial term of the agreement is to be for a period to complete the full implementation of Green Button by November 1, 2023, or earlier. In addition, the term of the agreement will continue for the support and management services portion, based on the use of the Selected Proponents solution by PUC, for a minimum of five (5) years, until 30 calendar days' notice is provided.

PART 3: THE DELIVERABLES

3.1 Background Information

The Ontario Energy Board (OEB) with the issuance of Ontario Regulation 633/21 under the Electricity Act, 1998 (Green Button Regulation) requires distributors (electricity and natural gas) to make available energy usage and account information identified in the NAESB ESPI standard that the distributor currently collects and make available to customers in the normal course of the distributor's operation. Energy usage information must be provided for interval of one hour or less and at least 24 months of usage data must be available (unless the customer has not held an account with the distributor for that long).

Green Button is part of the Ontario government's commitment to give consumers more choice when it comes to their energy use and will enable easy, quick, and secure access to their consumption data through smartphone or computer applications so they can find customized tips to reduce energy use or switch electricity price plans to save money.

PUC is looking for an integrated business partner which will assist us and new vendors in this process which will provide positive outcomes to our end user customers. The successful Proponent will help PUC drive our certification and implementation of Green Button which ensures the solutions meet not only our specific needs, which include digitization, but also the regulatory requirements by November 1, 2023. After Green Button has been implemented, PUC is also looking for ongoing management support services.

3.2 Must Categories

The proposed solution must follow Ontario Regulation 633/21, made under the Electricity Act, 1998. For greater certainty it must meet North American Energy Standards Board's (NAESB) REQ.21 Energy Services Provider Interface (ESPI) version 3.3 standard, and the Proponent must provide the following capabilities/services:

1. Aggregation of Data
    a. Either reading through the manual or hiring 3rd party vendor to help us aggregate data in required format. This data needs to be made available to all customers and any third parties that are request access to the data as authorized by customers. Please provide in detail how the process would work.
2. Customer Authorization and Revocation of Third-Party Access
    a. Authorization should only occur after a customer has gone through an authentication process to verify that they are the account holder. Distributors should also consider alternate authentication approaches for customers without an online account with the distributor. Please provide in detail how the process would work.
    b. Distributors should make the authorization form as simple as possible, and the form should only require such information as is reasonably necessary (i) to process the

authorization; and (ii) for the customer to understand the choice they are making to download or share their data.

c. The authorization form should include a clear statement to the effect that the customer is about to authorize the sharing of its energy usage and/or account information with a third party and that questions relating to the agreement between the customer and the third party, including how the third party will deal with their energy data, should be directed to the third party.
d. The authorization form should advise the customer that the third party will continue to have access to their data until such time as the customer revokes the authorization.
e. The authorization form should advise the customer that they can revoke the authorization at any time – with a link to information on how to revoke authorization.
f. The authorization form should inform the customer of the scope-of-use, to be provided by the third party, in relation to the data to be shared with the third party. For the scope of use to be included a third party must provide the exact statement to be included in the Customer Authorization Form to the distributor. The distributor should copy the statement exactly as provided by the third party and make it clear that the distributor it is not responsible for either the accuracy of the content nor the third party's actions in relation to the customer's energy data.
g. Update the Privacy Policy to make sure that it has covered implementation of Green Button. Privacy policy must be provided to customer when they authorize a third party to have access to their energy data and thereafter whenever the policy is updated. Authorization form should include a link to the distributors privacy policy
h. An understanding of the protocols being used in meeting the National Institute of Standards and Technology (NIST) and the North America Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP).

3.3 Objectives

To ensure the end customer experience meets the scope of the Green Button initiatives we are looking to see how the following categories will be addressed:

Information Technology:

- How the authorization form and authorization process is optimized for use on mobile devices;
- How the new technology via application program interfaces (API) would be integrated with existing PUC applications which would include MyPUC and our website. In addition, as PUC brings new applications the flexibility to integrate into Geographic Information System (GIS), the Sault Smart Grid (SSG) etc.;
- A description of the technology being proposed, i.e., software as a service (SaaS) or self-hosted;
- The ability of the software to incorporate the process for water consumption and analysis like what is required for electric and natural gas;

- An understanding on how the system's security/accessibility is being monitored?
- At present the reporting of information is based on what is currently provided, does the proposed solution provide flexibility if there is a modification in the interval times? For clarity PUC currently has information at one-hour intervals, if PUC decides to have a lower minimum can the system accommodate this.

Reporting:

All the various reports that the proposed solution can produce:

- Default reports
- Utilization by customers
- Exception reporting
- Summary activity
- Report Customization
- Other relevant key performance indicators

Customer Centric:

- How the proposed solution will integrate the currently billing data;
- To ensure a positive end customer experience how the proposed solution promotes ease of use to the end customer.
- How the proposed solution can integrate with PUC current website and its flexibility as the website is upgraded;
- What resources does the Proponent have in terms of videos, tutorials to assist the end customer on the utilization of the proposed solution;
- Information to support end customer support through the Proponent's ticket system.

3.4 Value Add On

- The focus of the RFP is on implementing Green Button; however, can you provide how you may integrate an upgrade to our Customer Connect and the associated costs;
- Assistance on how Green Button can assist PUC in its digitization strategy;
- Provide other value-added services which you provide which have not been listed in the RFP.

3.5 Schedule

Understanding the proposed solution must be implemented by November 1, 2023, please provide a detailed project schedule of when the services can start based on the RFP award date. Please address at a minimum:

- Planning Stage
    - o Conduct evaluation and solution selection
    - o Develop project plan and test plan
    - o Other….

- Solution Implementation
    - Set-up custodian and install solution
    - Connectivity testing
    - Training
    - Other….
- Solution Testing
    - Security testing
    - Data validation
    - Test case execution (ensuring data integrity)
    - Other….
- Implementation Readiness
    - Includes scheduling and Green Button Alliance certification testing
    - Solution installation with production environments
    - Other….
- Go Live
    - Based on approach could include soft launch and a marketing launch

Within each section, please include the proposed cadence of project meetings with PUC.

3.6 Qualifications

Please provide information pertaining to your company profile, the number of employees, the years of experience and qualification in providing this service.

In addition, please provide your company's experience in providing Green Button implementation services. This may include being part of the OEB Working Group or part of the Green Button Alliance. Please provide at a minimum three related references with details of the projects, preferably from different clients.

The Proponent should outline your company's experience in providing Green Button Implementation services to Ontario local distribution companies (LDC). Provide two related examples with details of the project.

Proponent should provide your company's best practices philosophy and how it supports development of its business relationship with PUC.

Proponent should identify the Project Manager to be assigned for this project. Provide a resume including summary of the Project Lead's education, experience and accreditations related to the project.

The resume should also include related project job information including:
• Name of organization
• Role and Responsibilities
• Dates and duration of the project

Proponent should identify the Team Member(s) who will be assigned to the project. Provide a resume including summary of each Team Member's project role, education, experience, and accreditations related to the project.

Each team member resume should also include related project job information including:
• Name of organization
• Role and Responsibilities
• Dates and duration of the project

Proponent should describe any subcontractors to be used in the provision of the Services. Include subcontractor name, role in project and a brief experience overview.

3.7 Internal Resources

Based on the schedule laid out in section 3.5, the Proponent should indicate any PUC resources required to support this Project (role and estimated number of hours) through each milestone. PUC's standard business hours are 9:00 a.m. - 4:30 p.m. Monday to Friday. It is expected that any requirements of PUC resources will be within standard business hours.

3.8 Risk Assessment Plan

Proponent should identify any potential risks that would be expected to emerge during this Project. Describe the respective impact(s) of these risks on the Project itself and assign a severity on a defined scale of minor/medium/major. Outline your companies risk mitigation strategies.

3.9 Accessibility for Ontarians with Disabilities (AODA)

The Deliverables of the RFP, the successful Proponent is required to comply with PUC's accessibility policies, practices and procedures established in accordance with the Accessibility for Ontarians with Disabilities Act, 2005 (AODA). As such, PUC must incorporate accessibility design, criteria and features when acquiring goods, services, or facilities.

3.10 Form of Services Agreement

Proponent should include a copy of its Form of Services Agreement as Appendix D - Form of Services Agreement. PUC will consider a Proponent's Form of Services Agreement. If the Proponent's Form of Services Agreement is not substantially acceptable, PUC will provide a Form of Services Agreement for the Successful Proponent's consideration. If the Successful Proponent cannot accept PUC's Form of Services Agreement, then PUC may disqualify the Successful Proponent's Proposal.

PUC acknowledges the need to add detailed requirements to the form of the Services Agreement.

PART 4: EVALUATION OF PROPOSALS

4.1 Stages of Proposal Evaluation

The evaluation of each Proponent's response to this RFP will be based on its demonstrated competence, compliance, format, and organization. The purpose of this RFP is to identify those Proponents that have the interest, capability, and capacity to supply PUC with the described Deliverables.

Proposal evaluation will consist of the following stages.

4.2 Stage I

Stage I will consist of a review to determine which Proposals comply with all the mandatory requirements. Proposals which do not comply with all the mandatory requirements may, subject to the express and implied rights of PUC, be disqualified and not evaluated further.

4.3 Stage II

Stage II will consist of a scoring by PUC of each qualified proposal based on the rated criteria.

4.4 Stage III

Upon completion of Stage II for all Proponents, the pricing provided by each Proponent will be reviewed and Stage III will consist of a scoring of the pricing submitted. The evaluation of price/cost shall be undertaken after the evaluation of the mandatory requirements and any rated requirements.

4.5 Stage IV

Stage IV will be consistent of a presentation of a shortlist of Proponents and scoring by PUC based on the rated criteria.

4.6 Stage V

At the conclusion of Stage IV, all scores from Stage II, Stage III and Stage IV will be added to determine the Total Score for each Proponent.

PART 5: MANDATORY & RATED REQUIREMENTS

5.1 Stage I – Mandatory Requirements

5.1.1 Sign Off (Appendix A)

Each Proposal must include a Sign Off Form (Appendix A) attesting the Proponent confirms the proposed solution follows Ontario Regulation 633/21, made under the Electricity Act, 1998. For greater certainty it must meet North American Energy Standards Board's (NAESB) REQ.21 Energy Services Provider Interface (ESPI) version 3.3 standard.

5.1.2 Reference Form (Appendix B)

Each proposal must include a Reference Form (Appendix B) completed by the Proponent. To validate the mandatory requirements and the RFP requirements, PUC may request to contact any of the references provided in Appendix B.

5.1.3 Rate Bid Form (Appendix C)

Each Proponent must include a Rate Bid Form (Appendix C) completed according to the Proponent's solution and provide for clear separation and understanding.

a) Quoted prices for the implementation of Green Button must include all charges as applicable. The payment schedule will be negotiated based on the final project schedule as outlined in Section 3.5.
b) Quoted prices for the annual ongoing management support for a minimum of five (5) years.
c) Pricing to be in Canadian funds.

5.1.4 Services Agreement (Appendix D)

Each Proponent must include two executed copies of their proposed Services Agreement.

5.2 Stage II – Evaluation of Rated Criteria

The following is an overview of the categories and weighting for the rated criteria of the RFP:
Rated Criteria Points:

a)	Reference	10 points
b)	Must Categories	25 points
c)	Objectives	25 points
d)	Value Add On	5 points
e)	Schedule	25 points
f)	Qualifications	20 points
g)	Internal Resources	20 points
h)	Risk Assessment	5 points

i) Accessibility for Ontarians with Disabilities 5 points

j) Form of Services Agreement 10 points

Total Points 150 points

5.3 Stage III – Evaluation of Pricing

Pricing will be scored based on a relative pricing formula using the prices set out in Appendix C: Rate Bid Form.

Each Proponent will receive a percentage of the total possible points allocated to pricing for the category it has bid on by dividing that Proponent's price for that category into the lowest bid price in that category. For example, if a Proponent bids $120.00 for a particular category and that is the lowest bid price in that category, that Proponent receives 100% of the possible points for that category (120/120 x Available Points = 100%). A Proponent who bids $150.00 receives 80% of the possible points for that category (120/150 x Available Points = 80%), and a Proponent who bids $240.00 receives 50% of the possible points for that category (120/240 x Available Points = 50%).

For example:

Lowest rate

---------- X Total Available Points = Pricing Points Score for Proposal with Second-lowest rate

Second-lowest rate

The points assigned to Stage III is 35 points.

5.4 Stage IV - Presentation

Stage IV will consist of presentations from a shortlist of the Proponent's software solution to the Evaluation Committee. The presentations will be conducted virtually through TEAMS and will not be longer than two hours.

The points assigned to Stage IV is 15 points.

5.5 Stage V - Evaluation Committee Review

The Evaluation Committee may select the Proposal which has achieved the highest points rating or may negotiate directly with one or more Proponents to determine the most favourable proposal, considering the overall ratings, the results of the negotiations, and any additional overriding factors that are relevant to the potential success of this project.

5.6 Evaluation Committee

An evaluation committee will be used to evaluate all qualified submissions. The evaluation committee will independently review and score each criterion comparatively to one another based on a 0-5 Rating Scale as described below.

Score	Description of Score
0	Represents that the item being evaluated was not addressed in the Proposal.
1	Represents that the item being evaluated is insufficient and there are significant deficiencies which are deemed not correctable.
2	Represents that the item being evaluated is below average and there were missing elements to the response.
3	Represents that the item being evaluated is about average, but there is insufficient information to make a dominant decision.
4	Represents that the item being evaluated is above average and minor improvements may be possible.
5	Represents that the item being evaluated is an excellent response and provided solutions for all parts of the item, with no deficiencies.

Once each evaluation team member has individually scored each Proposal, their scores will be sent to the RFP Lead Contact Person. The evaluation team will meet with the RFP Lead Contact Person to determine consensus scores for each Proposal.

PART 6: PROPOSALS SUBMISSION & FORMAT

6.1 Instructions to Vendors

Proposals in response to this RFP will be accepted until **4:00 p.m. on May 25, 2022,** by email and must be submitted in PDF format:

PUC Services Inc.
500 Second Line East
Sault Ste. Marie, P6A 4K1
ATTENTION: Shelley Hambly CSCMP
Email: purchasing.dept@ssmpuc.com

Proposals received after the closing deadline whether delivered personally, or if mailed, regardless of postal markings, will not be accepted. PUC reserves the right to alter the date of the proposal or to cancel this proposal without any penalty or cost to PUC.

The Proposal should be submitted by a person, or persons, duly authorized to bind the Proponent to contracts. The covering letter described in Section 6.3 will meet this requirement.

All financial information submitted by the Proponent will be used for evaluation purposes only and will be held in the strictest confidence.

6.2 RFP Response Format

Proponent must address all information specified by this RFP. All questions must be answered completely. PUC reserves the right to verify any information contained in the Proponents' RFP response, and to request additional information after the RFP response has been received.

Marketing brochures included as part of the bid response shall be considered as general background, but not as a substitute for written responses. In case of any conflict between the content in the attachments and a Proponent's answers in the body of the proposal, the latter will prevail.

6.3 Covering Letter

The Proposal must be accompanied by a covering letter and signed by an individual authorized to bind the Proponent.

6.4 Proposal Submission

Please note that it is the Proponent's responsibility to ensure that the Proposal and all other required documents are received at the address named above by the closing date and time specified and, in the format, specified.

PUC will be the sole judge of the qualifications of all prospective Proponents and reserves the right to reject all submittals without recourse.

PUC is aware that information contained in the proposals indicates the Proponent 's current operations. Therefore, use of this information shall be confined to this request and will be treated as confidential.

Proponents shall bear all costs associated with preparing and submitting responses to this RFP, and the subsequent evaluation phase. PUC will in no case be responsible for these costs, regardless of the conduct or outcome of the prequalification process.

SPREADSHEET INSTRUCTION WORKSHEET

Please complete the required tabs within the spreadsheet in order to provide PUC with the complete cost and information for this project.

Information

1. This spreadsheet contains many tabs providing information and instructions to Proponents, as well as proposal response documents.

APPENDIX A: Sign Off

Proponent Name: ______________________________

Read the instructions tab in this spreadsheet before completing.

I/We confirm the proposed solution in this RFP meets:

* Ontario Regulation 633/21 made under the Electricity Act, 1998

* North American Energy Standards Boards (NAESB) REQ 21 Energy Services provider Interface (ESPI) version 3.3 Standard.

______________________________ *(Print)*

______________________________ *(Position)*

______________________________ *(Signature)*

On behalf of:

______________________________ *(Proponent)*

APPENDIX B : List of References

Proponent Name: ______________________________

Read the instructions tab in this spreadsheet before completing.

Reference #1:

Company Name	
Contact Person	
Contact Phone Number	
Email Address	
Address and City	
Summary of Work	

Reference #2:

Company Name	
Contact Person	
Contact Phone Number	
Email Address	
Address and City	
Summary of Work	

Reference #3:

Company Name	
Contact Person	
Contact Phone Number	
Email Address	
Address and City	
Summary of Work	

APPENDIX C: Rate Bid Form

Proponent Name: ______________________________

Read the instructions tab in this spreadsheet before completing.

Green Button Implementation	Cost	Comments
Total		

Annual On Going Support	Cost	Comments
Year 1		
Year 2		
Year 3		
Year 4		
Year 5		
Total		

APPENDIX D: Services Agreement

Proponent Name: ______________________________

Read the instructions tab in this spreadsheet before completing.

As per Section 2.6 please include a two executed copies of the Proponent's Service Agreement.

Appendix B – Appendix IR16 – PUCD – Bill C97 Accelerated CCA_20221128

Appendix C – Appendix IR16 – PUCD – Bill C97 Accelerated CCA_20221128_SEC6

Appendix D – PUC Services Inc and PUC Distribution Inc Agreement

MANAGEMENT, OPERATIONS AND MAINTENANCE AGREEMENT

THIS AGREEMENT made as of January 1st, 2001.

B E T W E E N:

PUC SERVICES INC., a corporation incorporated under the laws of the Province of Ontario (hereinafter called the **"Manager"**),

OF THE FIRST PART;

-and-

PUC DISTRIBUTION INC., a corporation continued under the laws of the Province of Ontario (hereinafter called **"Distribution"**),

OF THE SECOND PART.

RECITALS

1. Distribution and the Manager have agreed to enter into this Agreement pursuant to which the Manager will assume responsibility for all aspects of the management operation and maintenance of Distribution's Business other than marketing and sales and subject to overall responsibility for management of Distribution by its senior officers and board of directors.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT, in consideration of the covenants and agreements herein contained, the parties hereto agree as follows:

ARTICLE ONE

DEFINITIONS AND SCHEDULES

1.1 Definitions

In this Agreement, unless something in the subject matter is inconsistent therewith, all capitalized terms shall have the meanings set forth below:

"Affiliate Relationships Code" means the Affiliate Relationships Code of the Ontario Energy Board as the same may be amended from time to time.

"Agreement" means this Agreement and all amendments made hereto in accordance with the provisions hereof.

"Business" means owning a distribution system in order to distribute electricity to customers, as well as business activities incidental thereto.

"Business Day" means a day other than Saturday, Sunday or a legal holiday in the City of Sault Ste. Marie, Ontario.

"Emergency Management Powers" means the powers of the Manager described in Section 2.2 (1)(d).

"Event of Default" means any of the events described in Section 6.1.

"Force Majeure" means a cause which is unavoidable or beyond the reasonable control of a party hereto and which by the exercise of due diligence such party is unable to prevent or overcome, including, without limitation, acts of God, acts of a public enemy, war, hostilities, invasion, insurrection, riot, the order of any competent civil or military government, explosion, fire, strikes, lockouts, labour disputes, malicious acts, vandalism, failure of equipment beyond the reasonable control of a party hereto, accident to any facilities, storms, or other adverse weather conditions, or other causes of a similar nature which wholly or partially prevent the parties or either of them from carrying out the terms of this Agreement (other than for the payment of monies due hereunder); provided that either party shall have the right to determine and settle any strike, lockout and labour dispute in which that party may be involved in its sole discretion and provided further that Force Majeure shall exclude lack of funds or economic hardship.

"Insolvent" means, in relation to any Person, being insolvent, bankrupt, making a proposal under the *Bankruptcy and Insolvency Act* (Canada) or having a trustee or receiver or manager appointed in respect of its assets.

"Prudent Industry Practice" means any of the practices, methods and acts which, in the exercise of reasonable judgment in the light of the facts known to the Manager, at the time that a decision was made, could reasonably have been expected to accomplish the desired result at a reasonable cost, consistent with applicable laws, licensing and regulatory considerations, environmental considerations, reliability, safety and expedition. Prudent Industry Practice is not intended to be limited to the optimum practice, method or act, to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts employed by owners and operators of facilities similar in size, type and operational characteristics to Distribution's facilities, and having due regard for applicable electrical, safety and maintenance codes and standards, manufacturers' warranties, and applicable laws and shall, in any event, evidence the degree of care, diligence and skill that a reasonably prudent advisor and manager having responsibility for the management of a similar business would exercise in comparable circumstances.

"Term" shall mean the period from the date hereof to the tenth anniversary hereof or such earlier date as this Agreement may be terminated in accordance with its terms.

1.2 Headings

The division of this Agreement into Articles, Sections, paragraphs and subparagraphs and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "hereof", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof and include any agreement supplemental hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles and Sections are to Articles and Sections of this Agreement.

1.3 Interpretation

Words importing the singular number only shall include the plural and vice versa, words importing gender shall include all genders. Where the word "including" or "includes" is used in this Agreement it means "including without limitation" or "includes without limitation", respectively. Any reference to any Document shall include a reference to any schedule, amendment or supplement thereto or any agreement in replacement thereof, all as permitted under the Documents.

1.4 Accounting Principles

Wherever in this Agreement reference is made to generally accepted accounting principles, such reference shall be deemed to be to the generally accepted accounting principles from time to time approved by the Canadian Institute of Chartered Accountants, or any successor institute, applicable as at the date on which such calculation is made or required to be made in accordance with generally accepted accounting principles. Where the character or amount of any asset or liability or item of revenue or expense is required to be determined, or any consolidation or other accounting computation is required to be made for the purpose of this Agreement or any document, such determination or calculation shall, to the extent applicable and except as otherwise specified herein or as otherwise agreed in writing by the parties, be made in accordance with generally accepted accounting principles applied on a consistent basis.

1.5 Funds

All dollar amounts referred to in this agreement are in lawful money of Canada.

ARTICLE TWO

THE MANAGER'S FUNCTIONS AND POWERS

2.1 Appointment of the Manager

Distribution hereby appoints the Manager and the Manager hereby accepts its responsibility for all aspects of the operation, maintenance, management and management of the Business in accordance with Prudent Industry Practice and the terms of this Agreement throughout the Term including without limitation providing all necessary staff to operate the Business but excluding marketing and sales services.

2.2 General Management Services

(1) The Manager shall have authority during the Term to manage, control, administer and operate the Business in accordance with Prudent Industry Practice, subject to the overall responsibility for management of Distribution by its senior officers ("Distribution Management") and the Distribution Board of Directors (the "Distribution Directors") and subject to and limited by the provisions of this Agreement.

Without limiting the generality of the foregoing, the Manager shall be vested with the following powers which it shall exercise on behalf of Distribution:

(a) to report to Distribution Management and the Distribution Directors with respect to the business and affairs of Distribution and the Business as may be requested from time to time by Distribution Management and the Distribution Directors;

(b) to provide all administrative services for the Business and Distribution including accounting and bookkeeping services;

(c) to negotiate, execute, amend, administer, perform and carry out the terms of all agreements and commitments, the performance of which by or on behalf of Distribution in respect of the Business and the Business is necessary or advisable; and

(d) to exercise emergency management powers in respect of any aspect of the operation and management of Distribution's facilities ("Emergency Management Powers") in order to take such action as a prudent owner of such facilities would normally take in the circumstances provided that (i) the Manager reasonably believes that immediate action is necessary to safeguard life or property or to prevent or minimize an interruption in the delivery of electricity, (ii) such action does not involve expenditures exceeding $1 million per occurrence in respect of any emergency unless the Manager has first received the approval of Distribution, and (iii) upon the exercise of Emergency Management Powers, the Manager shall forthwith notify Distribution Management and Distribution Directors in writing of the nature of the Emergency Management Powers exercised by it, the reasons for exercising Emergency Management Powers and the costs incurred or to be incurred by it in the exercise of the Emergency Management Powers.

2.3 Operations and Maintenance Services

Without limiting the generality of Section 2.2, the Manager shall provide or arrange for all of the operations and maintenance services necessary to prudently and efficiently operate and maintain Distribution's facilities, including but not limited to:

(a) co-ordinate the purchase and sale of electricity under applicable contracts and pay on behalf of Distribution and collect all amounts payable and receivable thereunder;

(b) operate and maintain the Business in accordance with Prudent Industry Practice, applicable laws and all Distribution agreements, to minimize unscheduled outages and to provide maintenance for Distribution's facilities in the most cost-effective manner to prevent deterioration beyond normal wear and tear; provided that such efforts shall be necessarily limited by the operating life, capacity and maintenance requirements of Distribution's facilities and by the requirements of all applicable laws;

(c) use all reasonable care necessary to keep Distribution's facilities clean, orderly and free from debris, rubbish or waste to the extent consistent with the operation of the Business;

(d) use all reasonable care not to generate, store, transport, accumulate, dispose, discharge or release any hazardous substance on, in or from any property in connection with Distribution's facilities, except in compliance with all applicable environmental laws and regulations;

(e) assist Distribution in obtaining and maintaining all necessary regulatory approvals including those required from the Ontario Energy Board for the Business and renewals therefor including preparing and submitting all associated applications and filings;

(f) use its reasonable efforts to secure and maintain from vendors, suppliers and subcontractors the best indemnities, warranties and guarantees as may be commercially available in accordance with Prudent Industry Practice regarding supplies, equipment and services purchased for the Business and assist Distribution in preserving and enforcing such indemnities, warranties or guarantees;

(g) provide administrative services for the Business and for Distribution in respect of the Business including:

(i) arrange insurance for the Business and Distribution consistent with Prudent Industry Practice;

(ii) maintain and preserve equipment maintenance, accounting, banking and other necessary records, reports, documents, data and the like for the Business and Distribution;

(iii) perform cash management services for the Business and Distribution;

(iv) on a timely basis prepare monthly and annual financial statements and deliver them to the Distribution Directors;

(v) assist in the administration of all agreements to which Distribution is a party or by which it is bound, including negotiations and communications with third parties in connection therewith; and

(vi) make all banking and financing arrangements;

(h) employ, and ensure adequate training and testing of all qualified personnel (duly licensed where required) required for the operation and maintenance of Distribution's facilities consistent with Prudent Industry Practice;

(i) implement an inventory control system to identity, catalogue and disburse spare parts for the maintenance of Distribution's facilities and procure, as agent for Distribution, initial and replacement spare parts and refurbish, where practical or economical, spare parts to allow their reuse;

(j) perform for Distribution such other services as may from time to time be reasonably requested or are reasonably necessary or appropriate in connection with the operation and maintenance of Distribution's facilities;

(k) promptly provide Distribution with such other information relative to the Business as Distribution may reasonably request;

provided that in the conduct of its duties hereunder, the Manager shall not, without first obtaining the written approval of the Distribution Directors undertake any activity which by the terms of the Shareholders' Agreement between Distribution and PUC Inc. requires the approval of PUC Inc.

2.4 <u>Covenants of the Manager</u>

The Manager covenants and agrees that in the performance of its services under this Agreement it shall:

(a) perform all services at all times in accordance with Prudent Industry Practice and in compliance with applicable laws and the Affiliate Relationships Code;

(b) comply with all instructions of Distribution Management of the Distribution Directors in relation to the performance of its services under this Agreement;

(c) observe and perform or cause to be observed and performed on behalf of Distribution in every material respect the provisions of (i) the agreements from time to time entered into in connection with the Business, and (ii) all applicable laws including the Affiliate Relationships Code;

2.5 No Liability of Manager

The Manager shall have no liability as a result of this Agreement to make or arrange for payments on account of operating expenses of Distribution or any other expenses relating to this Agreement out of its own funds.

ARTICLE THREE

TERM

3.1 Term of Agreement

This Agreement shall become effective as of the date hereof and shall continue in full force and effect until January 1st, 2011 unless sooner terminated in accordance with the provisions of this Agreement. This Agreement shall be automatically renewed for successive periods of five years unless either party provides the other with written notice to the contrary at least one hundred and eighty (180) days prior to the end of the then incumbent term.

ARTICLE FOUR

MANAGEMENT FEES

4.1 Management Fees

The parties shall negotiate, acting reasonably, the fees to be paid by Distribution to the Manager for the services hereunder. Such fees shall be determined annually and in compliance with the Affiliate Relationships Code. Any change in fees shall not be effective unless ratified by the Distribution Directors.

ARTICLE FIVE

FINANCIAL STATEMENTS, BUDGETS AND RECORDS

5.1 Books and Records

The Manager shall keep proper books, records and accounts in which full, true and correct entries in conformity with generally accepted accounting principles and all requirements of applicable laws will be made of all dealings and transactions in relation to the Business and the performance of the Manager's services under this Agreement at the Manager's head office.

5.2 Examination of Records

The Manager shall make available to Distribution and its authorized representatives at any time during normal business hours on a Business Day all records, documents or information related to the Business, wherever maintained. The Manager shall permit Distribution and its authorized representatives at any time during normal business hours on a Business Day to examine the books, records, drawings, computer-stored data, correspondence, accounting procedures and practices, cost analyses and any other supporting financial data, including invoices, payments or claims and receipts pertaining to the Business maintained by the Manager at its head office. Distribution's examination of records at the Business or at the Manager's head office shall be conducted in a manner which will not unduly interfere with the conduct of the Business or of the Manager's business in the ordinary course. The Manager shall furnish to Distribution such financial and operating data and other information with respect to the Business as Distribution shall from time to time reasonably request.

5.3 Confidentiality

The manager shall ensure that, unless required in connection with applicable laws, the books, records and accounts of Distribution (i) shall not be made available to any other person for whom the Manager provides services, and (ii) are not used by the Manager itself for any improper purpose, in compliance with the Affiliate Relationships Code.

ARTICLE SIX

DEFAULT AND TERMINATION

6.1 Event of Default

The Manager shall be in default under this Agreement upon the happening or occurrence of any of the following events, each of which shall be deemed to be an Event of Default for the purposes of this Agreement:

(a) the Manager breaches or fails to observe or perform any of the Manager's material obligations, covenants, or responsibilities under this Agreement, and, within thirty (30) days after notice from Distribution specifying the nature of such breach or failure, to the satisfaction of Distribution Management and the Distribution Directors, the Manager fails to cure such breach or failure or to take steps to remedy such breach or failure and give reasonable assurances to Distribution that such default shall be cured within a period of time satisfactory to Distribution Management and the Distribution Directors;

(b) the Manager:

(i) becomes Insolvent;

(ii) is subject to any proceeding, voluntary or involuntary, under the provisions of the *Bankruptcy and Insolvency Act* (Canada), the *Companies Creditors Arrangement Act* (Canada), or any other Act for the benefit of creditors;

(iii) goes into liquidation;

(iv) winds up either voluntarily or under an order of a Court of competent jurisdiction;

(v) makes a general assignment for the benefit of its creditors; or

(vi) otherwise takes any corporate action that acknowledges its Insolvency; or

(c) gross negligence, wilful default or fraud by the Manager in the performance of any of its obligations, covenants, or responsibilities under this Agreement.

6.2 Termination by Distribution

Upon the occurrence of an Event of Default of the Manager but subject to section 6.3, Distribution may without recourse to legal process but without limiting any other rights or remedies which it may have at law or otherwise, terminate this Agreement by delivery of written notice of termination to the Manager.

6.3 Restriction on Termination during Force Majeure

During the occurrence of an event of Force Majeure, the obligations of the party affected by such event of Force Majeure, to the extent that such obligations cannot be performed as a result of such event of Force Majeure, shall be suspended, and such party shall not be considered to be in default hereunder, for the period of such occurrence except that the occurrence of an event of Force Majeure affecting Distribution (but not affecting the performance of the Manager's obligations hereunder) shall not relieve it of its obligation to make payments to the Manager hereunder. The non-performing party shall give the other party prompt written notice of the particulars of the event of Force Majeure and its expected duration, shall continue to furnish regular reports with respect thereto on a timely basis during the continuance of the event of Force Majeure and shall use its best efforts to remedy its inability to perform. The suspension of performance is to be of no greater scope and of no longer duration than is required by the Force Majeure condition. No obligations of either party that arose before the

Force Majeure causing the suspension of performance are excused as a result of the Force Majeure.

6.4 Post-Termination Arrangements

In the event of termination of this Agreement:

(a) the Manager shall deliver to Distribution all books, records, accounts, systems and manuals which it has developed and maintained relating to Distribution, Distribution's facilities and the Business pursuant to this Agreement;

(b) the parties shall take all steps as may be reasonably required to complete any final accounting between them and to provide, if applicable, for the orderly transfer of insurance and completion of any other matter contemplated by this Agreement; and

(c) title to all materials, equipment, supplies, consumables, spare parts and other items purchased or obtained by the Manager for the Business shall pass to and vest in Distribution upon the passage of title from the vendor or supplier thereof and payment or reimbursement of costs by Distribution.

ARTICLE SEVEN

GENERAL MATTERS

7.1 Governing Law

This Agreement shall be conclusively deemed to be a contract made under, and shall for all purposes be construed and interpreted in accordance with the laws of the Province of Ontario, and the laws of Canada applicable in such Province.

7.2 Benefit of the Agreement

This Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective successors and permitted assigns.

7.3 Severability

Any provision of this Agreement which is prohibited or unenforceable in any jurisdiction shall not invalidate the remaining provisions hereof and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. In respect of any provision so determined to be unenforceable or invalid, the parties agree to negotiate in good faith to replace the unenforceable or invalid provision with a new provision that is enforceable and valid in order to give effect to the business intent of the original provision to the extent permitted by law and in accordance with the intent of this Agreement.

7.4 Amendments and Waivers

No modification of or amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by both of the parties hereto and no waiver of any breach of any term or provision of this Agreement shall be effective or binding unless made in writing and signed by the party purporting to give the same and, unless otherwise provided, shall be limited to the specific breach waived.

7.5 Further Assurances

Each of Distribution and the Manager shall from time to time execute and deliver all such further documents and instruments and do all acts and things as the other party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement.

7.6 Time of the Essence

Time shall be of the essence of this Agreement.

7.7 No Partnership

It is understood and agreed that nothing contained in this Agreement nor any acts of the parties shall be deemed to constitute the Manager and Distribution as partners of each other.

IN WITNESS WHEREOF this Agreement has been executed by the parties hereto as of the day of February, 2001.

PUC SERVICES INC.

Per: ______________________

Per: ______________________

PUC DISTRIBUTION INC.

Per: ______________________

Per: ______________________

MANAGEMENT, OPERATIONS AND MAINTENANCE AGREEMENT

AMENDING AGREEMENT

THIS AGREEMENT made the 10th day of November, 2011.

BETWEEN:

PUC SERVICES INC.

(hereinafter called the "Manager")

OF THE FIRST PART

- and –

PUC DISTRIBUTION INC.

(hereinafter called "Distribution")

OF THE SECOND PART

NOW THEREFORE for good and valuable consideration the receipt and sufficiency of which are hereby acknowledged, the Manager and Distribution agree as set forth herein.

1.0 BACKGROUND

1.1 Manager and Distribution are parties to a Management, Operations and Maintenance Agreement dated January 1st, 2001, a copy of which is annexed hereto (the "Original Agreement").

1.2 In order to more efficiently carry out the obligations of the Manager as set forth in the Original Agreement the Manager has entered into a Lease for certain facilities being constructed on property at 500 Second Line East, Sault Ste. Marie, Ontario (the "Facilities"). The commencement date of the Lease is December 1st, 2012 (the "Effective Date")

2.0 AMENDMENTS

2.1 As of the Effective Date the determination of the Manager's fees in paragraph 4.1 shall be cancelled and commencing as of the Effective Date the following provision shall apply:

4.1 Management Fees

In consideration of the Manager undertaking the management, operation, and maintenance of Distribution's Business and the provision of the services set forth in paragraphs 2.2 and 2.3 hereof, Distribution agrees to pay to the Manager a monthly fee consisting of the direct costs specifically attributable to Distribution plus Distribution's proportionate share (as set forth herein) of the costs incurred by the Manager for the shared services (direct costs and shared costs collectively referred to as the "Costs") incurred by the Manager in the fulfilment of the Manager's obligations pursuant to all service contracts administered by the Manager. The Costs shall be determined by the Manager and payment shall be made by Distribution monthly within fifteen (15) days of the Manager submitting an invoice for payment to Distribution. For the purpose of this paragraph Distribution's proportionate share shall be 46% subject to periodic adjustment by the Manager. If Distribution disagrees with the Manager's determination of the Costs or any adjustment to Distribution's proportionate share, the dispute shall be submitted to a single qualified, experienced arbitrator pursuant to the *Arbitration Act, 1991* (Ontario) and the decision of the arbitrator shall be binding on the parties. The cost of arbitration shall be borne equally between the parties.

For greater clarity, the calculation of any rent included in the Costs for workshop and garage facilities and administrative offices presently owned or leased by the manager or to be owned or leased by the Manager (collectively the "Facilities") during the term of this agreement and used in the operation of Distribution's Business shall be based on the following formula:

> Rent = Capital cost of the Facilities divided by the estimated useful life (in years) of the Facilities plus the cost of capital. For the purposes of this formula "costs of capital" is the capital cost of the Facilities x the cost of capital as established by the Ontario Energy Board from time to time.

2.2 Manager and Distribution agree that until the Effective date the provisions contained in the Original Agreement with respect to the determination of management fees shall continue in full force and effect.

2.3 Manager and Distribution agree that the term of the Original Agreement is hereby extended to November 30th, 2012. The provisions regarding automatic renewal set forth in paragraph 3.1 of the Original Agreement shall continue to apply.

3.0 <u>GENERAL</u>

3.1 This Agreement shall be read together with the Original Agreement and the parties confirm that except as modified herein all covenants and conditions in the Original Agreement remain unchanged, unmodified and in full force and effect.

3.2 Any capitalized word or term not otherwise defined herein shall have the meaning given thereto in the Original Agreement.

3.3 The parties agree to do or cause to be done from time to time all such things and shall execute and deliver all such documents, agreements and instruments reasonably requested by the other party as may be necessary or desirable to carry out the provisions and intentions of this Agreement.

3.4 This Agreement shall ensure to the benefit of and be binding upon the parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF the parties hereto have executed this Agreement.

PUC SERVICES INC.

Per: ______________________

Per: ______________________

We have authority to bind the Corporation

PUC DISTRIBUTION INC.

Per: ______________________

Per: ______________________

We have authority to bind the Corporation

Appendix E – Exhibit 9 -Tables_20221212

Table 1-12 Deferral and Variance Accounts

Accounts Requested for Disposal	Account Number	Claim	RPP	Non RPP
Group 1 Accounts:				
Smart Metering Entity Charge Variance Account	1551	($17,194)	($16,443)	($750)
RSVA - Wholesale Market Service Charge	1580	$914,291	$602,033	$312,259
RSVA - Wholesale Market Service Charge - CBR	1580	($76,540)	($53,945)	($22,595)
RSVA - Retail Transmission Network Charge	1584	$452,702	$298,090	$154,612
RSVA - Power (excluding Global Adjustment)	1588	($1,187,959)	($782,234)	($405,724)
RSVA - Global Adjustment	1589	($73,875)	$0	($73,875)
Subtotal - Group 1 Accounts		**$11,425**	**$47,500**	**($36,075)**
Group 2 Accounts:				
Other Regulatory Assets - Sub-Account - Pole Attachment Variance	1508	$69,334	$45,654	$23,680
COVID-19 Rate Implementation Delay Variance Account (net)	1509	($1,929)	($1,270)	($659)
COVID-19 ICM Rate Implementation Delay Variance Account (net)	1509	($51,943)	($34,203)	($17,740)
COVID-19 Incremental Expense Variance Account	1509	$405,498	$267,008	$138,490
Retail Cost Variance Account - Retail	1518	($18,852)	($12,413)	($6,438)
Retail Cost Variance Account - STR	1548	$65,798	$43,326	$22,472
PILs & Taxes Variance	1592	($619,378)	($407,841)	($211,537)
Subtotal - Group 2 Accounts		**($151,471)**	**($99,739)**	**($51,732)**
Other Accounts:				
LRAM Variance Account	1568	$198,189	$130,891	$67,298
Subtotal - Other Accounts		**$198,189**	**$130,891**	**$67,298**
Subtotal - Group 2 Accounts &Other Accounts		**$46,718**	**$31,152**	**$15,566**
Total		**$58,143**	**$78,652**	**($20,509)**

Table 9-4: DVAs Requested for Disposal in 2023 Application

Account Name	Account Number	Total Principal & Interest (Dec 31, 2021)	2021 Disposal	COS Adjustments	Principal & Interest Disposed	Interest to April 30, 2023	Balances April 30, 2023 Total Claim
Group 1 Accounts:							
Smart Metering Entity Charge Variance Account	1551	($16,709)	$50	$0	($16,659)	($535)	($17,194)
RSVA - Wholesale Market Service Charge	1580	$656,641	$229,218	$0	$885,859	$28,432	$914,291
RSVA - Wholesale Market Service Charge - CBR	1580	($106,818)	$32,083	$0	($74,735)	($1,805)	($76,540)
RSVA - Retail Transmission Network Charge	1584	$687,230	($248,553)	$0	$438,677	$14,025	$452,702
RSVA - Power (excluding Global Adjustment)	1588	($980,375)	($170,617)	$0	($1,150,993)	($36,966)	($1,187,959)
RSVA - Global Adjustment	1589	$481,319	($552,595)	$0	($71,276)	($2,599)	($73,875)
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	$25,810	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	($24,486)	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	$228,535	$0	$0	$0	$0	$0
Subtotal - Group 1 Accounts		**$951,147**	**($710,414)**	**$0**	**$10,874**	**$552**	**$11,425**
Account Name	**Account Number**	**Total Principal & Interest (Dec 31, 2021)**	**2022/2023 Forecast Transactions**	**COS Adjustments**	**Principal & Interest Disposed**	**Interest to April 30, 2023**	**Total Claim**
Group 2 Accounts:							
Other Regulatory Assets - Sub-Account - Pole Attachments	1508	($26,732)	$0	$93,876	$67,144	$2,190	$69,334
Other Regulatory Assets - Sub-Account - ICM Substation 16 Capital	1508	$6,020,120	$0	($6,020,120)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Substation 16 Depreciation	1508	$75,251		$150,503	$225,754		$0
Other Regulatory Assets - Sub-Account - ICM Substation 16 Accumulated Depreciation	1508	($75,251)		($150,503)	($225,754)		$0
Other Regulatory Assets - Sub-Account - ICM Substation 16 Rate Riders	1508	($269,820)	($315,037)	$0	($584,857)	$1,389	($583,468)
Other Regulatory Assets - Sub-Account - ICM Substation 16 Rate Riders Revenue Revised	1508	$0	$632,807	$0	$632,807	$0	$632,807
Other Regulatory Assets - Sub-Account - ICM Substation 16 Delayed Rate Implementation	1508	($115,142)	$0	$0	($115,142)	$0	($115,142)
COVID-19 Foregone Revenue - ICM Substation Delayed Rate Implementation	1508	$115,142	$0	$0	$115,142	$3,690	$118,832
COVID-19 Foregone Revenue - ICM Substation 16 Rate Rider	1508	($59,155)	($42,557)	$0	($101,712)	($3,260)	($104,972)
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Capital	1508	$0	$21,357,909	($21,357,909)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Depreciation	1508	$0	$500,407	($500,407)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Accumulated Depreciation	1508	$0	($500,407)	$500,407	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Rate Rider	1508	$0	($852,614)	$852,614	$0	$0	$0
COVID-19 Delayed Implementation IRM Forgone Revenue	1509	$192,359	$0	$0	$192,359	$6,165	$198,524
COVID-19 Delayed Implementation IRM Rate Rider Recovery	1509	($101,703)	($92,525)	$0	($194,228)	($6,225)	($200,453)
COVID-19 Incremental Expense Variance Account	1509	$393,222	$0	$0	$393,222	$12,276	$405,498
Retail Cost Variance Account - Retail	1518	($6,188)	($12,107)	$0	($18,295)	($557)	($18,852)
Retail Cost Variance Account - STR	1548	$53,395	$10,433	$0	$63,828	$1,970	$65,798
PILs & Taxes Variance	1592	($410,974)	($189,219)	$0	($600,193)	($19,185)	($619,378)
Subtotal - Group 2 Accounts		**$5,784,524**	**$20,497,090**	**($26,431,539)**	**($149,925)**	**($1,547)**	**($151,472)**
Other Accounts:							
LRAM Variance Account (2018 COS)	1568	$14,263	($22,841)	$0	($8,578)	($645)	($9,223)
LRAM Variance Account (2023 COS)	1568	$0	$201,460	$0	$201,460	$5,952	$207,412
Subtotal - Other Accounts		**$14,263**	**$178,619**	**$0**	**$192,882**	**$5,307**	**$198,189**
Total Group 2 Accounts		**$5,798,787**	**$20,675,710**	**($26,431,539)**	**$42,958**	**$3,760**	**$46,718**
Total		**$6,749,934**	**$19,965,295**	**($26,431,539)**	**$53,831**	**$4,312**	**$58,143**

Table 9-5: Principal Activity included in Group 2 Disposition

Group 2 Account Description	Account Number	Principal Amounts Included in Proposed Disposition
Group 2 Accounts:		
Other Regulatory Assets - Sub-Account - Pole Attachments	1508	to April 30, 2023
COVID-19 Delayed Implementation IRM Forgone Revenue	1509	to October 31, 2022
COVID-19 Delayed Implementation IRM Rate Rider Recovery	1509	to October 31, 2022
COVID-19 Incremental Expense Variance Account	1509	to December 31, 2021
COVID-19 Delayed Implementation ICM Substation Forgone Revenue	1509	to October 31, 2022
COVID-19 Delayed Implementation ICM Substation Rate Rider	1509	to October 31, 2022
Retail Cost Variance Account - Retail	1518	to April 30, 2023
Retail Cost Variance Account - STR	1548	to April 30, 2023
PILs & Taxes Variance	1592	to December 31, 2022
LRAM Variance Account (2018 COS)	1568	to December 31, 2021
LRAM Variance Account (2023 COS)	1568	to April 30, 2022
Other Regulatory Assets - Sub-Account - ICM Substation 16	1508	to December 31, 2021
Other Regulatory Assets - Sub-Account - ICM Substation 16 Rate Rider	1508	to April 30, 2023
Other Regulatory Assets - Sub-Account - ICM Substation Forgone Revenue	1508	to October 31, 2022
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid	1508	to December 31, 2021
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Rate Rider	1508	to April 30, 2023

Table 9-6: Group 1 DVAs Requested for Disposal

Account Name	Account Number	Principal & Interest Disposed	Interest to April 30, 2023	Balances April 30, 2023 Total Claim
Group 1 Accounts:				
Smart Metering Entity Charge Variance Account	1551	($16,659)	($535)	($17,194)
RSVA - Wholesale Market Service Charge	1580	$885,859	$28,432	$914,291
RSVA - Wholesale Market Service Charge - CBR	1580	($74,735)	($1,805)	($76,540)
RSVA - Retail Transmission Network Charge	1584	$438,677	$14,025	$452,702
RSVA - Power (excluding Global Adjustment)	1588	($1,150,993)	($36,966)	($1,187,959)
RSVA - Global Adjustment	1589	($71,276)	($2,599)	($73,875)
Subtotal - Group 1 Accounts		**$10,874**	**$552**	**$11,425**

Table 9-7: Group 2 DVAs Requested for Disposal

Account Name	Account Number	Total Principal & Interest (Dec 31, 2021)	2022/2023 Forecast Transactions	COS Adjustments	Principal & Interest Disposed	Interest to April 30, 2023	Total Claim
Group 2 Accounts:							
Other Regulatory Assets - Sub-Account - Pole Attachments	1508	($26,732)	$0	$93,876	$67,144	$2,190	$69,334
Other Regulatory Assets - Sub-Account - ICM Substation 16	1508	$6,020,120	$0	($6,020,120)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Substation 16 Depreciation	1508						
Other Regulatory Assets - Sub-Account - ICM Substation 16 Accumulated Depreciati	1508						
Other Regulatory Assets - Sub-Account - ICM Substation 16 Rate Rider	1508	($269,820)	($315,037)	$0	($584,857)	$1,389	($583,468)
Other Regulatory Assets - Sub-Account - ICM Substation16 Rate Rider Revenue Revised		$0	$632,807			$0	$632,807
Other Regulatory Assets - Sub-Account - ICM Substation Forgone Revenue	1508	($115,142)	$0	$0	($115,142)	$0	($115,142)
COVID-19 Delayed Implementation ICM Substation Forgone Revenue	1508	$115,142	$0	$0	$115,142	$3,690	$118,832
COVID-19 Delayed Implementation ICM Substation Rate Rider	1508	($59,155)	($42,557)	$0	($101,712)	($3,260)	($104,972)
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid	1508	$0	$21,357,909	($21,357,909)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Depreciation	1508						
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Accumulated Depreci	1508						
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Rate Rider	1508	$0	($852,614)	$852,614	$0	$0	$0
COVID-19 Delayed Implementation IRM Forgone Revenue	1509	$192,359	$0	$0	$192,359	$6,165	$198,524
COVID-19 Delayed Implementation IRM Rate Rider Recovery	1509	($101,703)	($92,525)	$0	($194,228)	($6,225)	($200,453)
COVID-19 Incremental Expense Variance Account	0	$393,222	$0	$0	$393,222	$12,276	$405,498
Retail Cost Variance Account - Retail	0	($6,188)	($12,107)	$0	($18,295)	($557)	($18,852)
Retail Cost Variance Account - STR	0	$53,395	$10,433	$0	$63,828	$1,970	$65,798
PILs & Taxes Variance	1592	($410,974)	($189,219)	$0	($20,804)	($19,185)	($619,378)
Subtotal - Group 2 Accounts		**$5,784,524**	**$20,497,090**	**($26,431,539)**	**($203,343)**	**($1,547)**	**($151,472)**
Other Accounts:							
LRAM Variance Account (2018 COS)	1568	$14,263	($22,841)	$0	($8,578)	($645)	($9,223)
LRAM Variance Account (2023 COS)	1568	$0	$201,460	$0	$201,460	$5,952	$207,412
Subtotal - Other Accounts		**$14,263**	**$178,619**	**$0**	**$192,882**	**$5,307**	**$198,189**
Total Group 2 Accounts		**$5,798,786**	**$20,675,710**	**($26,431,539)**	**($10,461)**	**$3,760**	**$46,717**

Table 9-15 – Group 2 Accounts – Commence/Continue/Discontinue

Table 1-13 DVAs Commence/Continues/Discontinue

Group 2 and Other Accounts	Account Number	Commence Continue Discontinue	Explanation
Other Regulatory Assets - Sub Account - Incremental VVO Savings or Costs	1508	Commence	To record on-going SSG VVO impacts.
Other Regulatory Assets - Sub Account - EPC Contract Liquidated Damages	1508	Commence	To record liquidated damages due to performance or delay in EPC contract.
Other Regulatory Assets - Sub Account - SSG Foregone Revenue Requirement	1508	Commence	To record on-going SSG Foregone Revenue
Other Regulatory Assets - Sub-Account - Pole Attachment	1508	Continue	On-going in event of a decrease in expected Pole Rental charge.
PILs and Tax Variance	1592	Continue	Remain available to use for other legislative tax changes not reflected in rates.
LRAM Variance Account	1568	Continue	On-going in event of future CDM programs.
Other Regulatory Assets - Sub-Account - ICM Sub-station 16	1508	Discontinue	Rate Rider in effect until April 30, 2023
Other Regulatory Assets - Sub-Account - Sault Smart Grid	1508	Discontinue	Rate Rider in effect until April 30, 2023
COVID-19 Deferral Account	1509	Discontinue	Final disposition at rebasing; no activity expected
Retail Cost Variance Account - Retail	1518	Discontinue	Final disposition at rebasing; forecast activity to April 30, 2023
Retail Cost Variance Account - STR	1548	Discontinue	Final disposition at rebasing; forecast activity to April 30, 2023

Table 9-17: Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj. and Account 1580 WMS CBR Class B)

Rate Class	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL SERVICE CLASSIFICATION	kWh	274,738,681	$ 69,712	0.0003
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ 22,807	0.0003
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	547,687	$ 68,221	0.1259
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ 273	0.0003
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ 766	0.1064
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ 60	0.1066
Total			**$ 161,840**	

Table 9-18: Rate Rider Calculation for Account 1580 WMS, sub-account CBR Class B

Rate Class	Units	kW / kWh / # of Customers	Allocated Sub-account 1580 CBR Class B Balance	Rate Rider for Sub-account 1580 CBR Class B
RESIDENTIAL SERVICE CLASSIFICATION	kWh	274,738,681	$ (38,975)	(0.0001)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ (11,229)	(0.0001)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	458,921	$ (25,832)	(0.0570)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ (125)	(0.0001)
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ (350)	(0.0487)
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ (28)	(0.0488)
Total			**$ (76,540)**	

Table 9-19: Rate Rider Calculation for RSVA - Power - Global Adjustment

Rate Class	Units	kW / kWh / # of Customers	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL SERVICE CLASSIFICATION	kWh	3,364,092	$ (1,472)	(0.0004)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	12,067,162	$ (5,279)	(0.0004)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kWh	151,116,068	$ (66,106)	(0.0004)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	-	$ -	-
STREET LIGHTING SERVICE CLASSIFICATION	kWh	2,330,282	$ (1,019)	(0.0004)
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	-	$ -	-
Total			**$ (73,876)**	

Table 9-20: Rate Rider Calculation for Group 2 Deferral / Variance 1 Accounts Balances

Rate Class	Units	kW / kWh / # of Customers	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	30,340	$ (244,196)	(0.6707)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ (78,034)	(0.0010)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	547,687	$ (240,860)	(0.4444)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ (861)	(0.0010)
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ 6,738	0.9358
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ 244	0.4312
Total			**$ (556,969)**	

Table 9-21 - Rate Rider Calculation for Account 1568 LRAMVA

Rate Class	Units	kW / kWh / # of Customers	Allocated Account 1568 Balance	Rate Rider for Account 1568
RESIDENTIAL SERVICE CLASSIFICATION	kW	274,738,681	$ 44,507	0.0002
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ (110,221)	(0.0014)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	547,687	$ 263,903	0.4869
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ -	-
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ -	-
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ -	-
Total			**$ 198,189**	

Table 9-22 - Rate Rider Calculation for Account 1509 COVID-19 Incremental Expense

Rate Class	Units	kW / kWh / # of Customers	Allocated Account 1509 Balance	Rate Rider for Account 1509
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	30,340	$ 248,864	0.6835
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	# of Customers	3,400	$ 61,340	1.5034
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	# of Customers	344	$ 89,493	21.6794
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	# of Customers	25	$ 818	2.7272
STREET LIGHTING SERVICE CLASSIFICATION	# of Customers	8,037	$ 4,279	0.0444
SENTINEL LIGHTING SERVICE CLASSIFICATION	# of Customers	317	$ 705	0.1852
Total			**$ 405,498**	

Appendix F – 17 Trees PO

Bill To: accounts.payable@ssmpuc.com

As of Aug 1st 2021 PUC will only be accepting electronic/digital invoices.
Please ensure your PDF invoice is emailed to the above address

Address: 500 Second Line East
Post Office Box 9000
Sault Ste. Marie, ON P6A 6P2

PO Number: BP-213

PO Date: 01/01/2022
Expiration Date 12/31/2022
PO Amount: 680000

Vendor: 17 TREES INC.
02246 500 SECOND LINE EAST
SAULT STE MARIE PO BOX 9000 ON P6A 6P2

Ship To: PUC SERVICES INC.
500 SECOND LINE EAST
SAULT STE MARIE, ON P6B 4K1

Terms: NET 30
Ship Via: Bestway
PR Number: PR-19960
F.O.B. DESTINATION
PO Desc: LINE Vegetation Management - for 2022

LINE	DESCRIPTION	QTY	UNIT	UNIT PRICE	TOTAL
	SCOPE OF WORK. To provide utility arborist services in accordance with PUC's 2022 vegetation management program, in addition to ad hoc related customer demand work as required. Hourly billable crew rates will be in accordance with the approved shareholder crew rates for 2022, as attached. 17 Trees Inc. will provide all equipment, tools, and labour for the services provided and agrees to comply with all applicable PUC policies, procedures and standards for vegetation management.				
1	2022 Vegetation Management	680000	$	$1.00	$680,000.00

Subtotal:	**$680,000.00**
HST	**$88,400.00**
PO Total:	**$768,400.00**

PRICE CORRECTIONS & TERMS must be confirmed before delivery of goods or original Purchase Order Pricing will be honoured by Vendor

All equipment provided for the construction or repair of the electrical distribution system must meet the requirements of Ontario Regulation 22/04. This requirement can be met by electrical equipment that is approved in accordance with the requirements of the Ontario Electrical Safety Code Rule 2-024 (CSA Certified or equivalent). Alternative equipment approval requirements are outlined in O. Reg. 22/04.

All non-distribution type electrical equipment (ancillary equipment) must be approved in accordance with the requirements of the Ontario Electrical Safety Code Rule 2-024.

Any item not meeting the above two requirements will be returned at the supplier's expense.
Kindly quote this Purchase Order number on all invoices, packing lists, containers and correspondences Failure to comply with delivery date could be cause for cancellation of order at no cost to Purchaser. You are required to supply new or updated Material Safety Data Sheets (M.S.D.S) for all hazardous materials.

PUC Services Inc. has implemented a quality management system for safe drinking water that meets the requirements of the Ontario Ministry of the Environment's Drinking Water Quality Management Standard

01-Jan-2022

Shelley Hambly Date

PUC Purchasing Dept. 705-759-6530 purchasing.dept@ssmpuc.com

HST Number: R122198567

17 TREES INC.
500 Second Line E
PO Box 9000
Sault Ste Marie, ON
P6A 6P2

2022 RATE SHEET
Arborist Services
effective January 1, 2022

Rate Description	Shareholder Hourly Internal Regular rate	Shareholder Hourly Overtime rate
2 person crew	[redacted]	
3 person crew		

PURCHASE ORDER TERMS AND CONDITIONS

1. Definitions

In these Standard Purchase Terms, the following definitions apply:

a) **Agreement** means the agreement between Supplier and Buyer for the purchase of goods and/or services;

b) **Buyer** means PUC Services Inc.;

c) **Deliverable** means any deliverable or other product or result from services that is referred to in a Purchase Order and any related materials, data, documentation and includes any intellectual property rights developed by Supplier pursuant to such Purchase Order;

d) **Delivery Date** means the date of delivery for goods or performance of services as specified in the Purchase Order;

e) **Delivery Point** means the location identified by Buyer in the Purchase Order to which Supplier is to deliver goods and/or perform the services or such other delivery area or point which is specified in writing by Buyer;

f) **Goods** means the goods that are required to be delivered by Supplier pursuant to a Purchase Order and includes all materials, component parts, packaging and labelling of such goods;

g) **Intellectual Property Rights** means all intellectual and industrial property rights and rights of a similar nature including all rights in and to patents, including all issued patents and pending applications therefore, and patents which may be issued therefrom (including divisions, re-issues, re-examinations, continuations and continuations in part); trade-marks, copyrights, industrial design rights, rights pertaining to trade secrets and confidential information, publicity rights, personality rights, moral rights, and other intellectual property rights, whether registered or not and all applications, registrations, renewals and extensions pertaining to the foregoing;

h) **Purchase Order** means the Purchase Order between Buyer and Supplier for the purchase and sale of goods and/or services to which the standard purchase terms are attached or are incorporated by reference;

i) **Services** means any services to be provided by Supplier to Buyer pursuant to a Purchase Order;

j) **Specifications** means the requirements, attributes and specifications for the goods or services that are set out in the applicable Purchase Order. Specifications also include:

   i) Documentation published by Supplier relating to the goods and services;

ii) Operational and technical features and functionality of the goods and services;

iii) Standards or level of service, performance for services; and,

iv) Buyer business requirements that are expressly set out in a Purchase Order;

k) **Supplier** means the party indicated on the face page of the Purchase Order that is contracting with Buyer for the purchase and sale of goods and/or services;

l) **Supplier Proposal** means any acknowledgement, estimate, quote, offer to sell, invoice, or proposal of Supplier relating to the supply of goods and/or services to Buyer including any delivered in connection with a request for quotations, request for proposal or similar process initiated by Buyer;

m) **Warranty Period** means in respect of any goods or services, the longer of:

i) The express written warranty period provided by Supplier for the goods and services; and,

ii) The period commencing on the date of acceptance of such goods or services and ending on the date that is one (1) year from that date.

2. Agreement

The Agreement consists only of:

a) These standard purchase terms;

b) The applicable Purchase Order; and,

c) Any specifications or other documents expressly referenced in the Purchase Order.

Any reference in the Purchase Order to any supplier proposal is solely for the purpose of incorporating the descriptions and specifications of the goods and/or services contained in the proposal and only to the extent that the terms of Supplier proposal do not conflict with the descriptions and specifications set out in the Purchase Order. Buyer's acceptance of, or payment for goods and/or services, will not constitute Buyer's acceptance of any additional or different terms in any Supplier proposal unless otherwise accepted in writing by Buyer. If there is any conflict or inconsistency between the documents constituting the Agreement, then unless otherwise expressly provided, the documents will rank in the order of precedence in accordance with the order in which they are listed in Section 2.

3. Delivery of Goods and Services

a) Supplier agrees to supply and deliver the goods to Buyer and to perform the services as applicable, on the terms set out in this Agreement;

b) Supplier shall, at its own expense, pack, load and deliver goods to the delivery point and in accordance with the invoicing, delivery terms, shipping, packing and other instructions printed on the face of the Purchase Order or otherwise provided to Supplier by Buyer in writing. No charges will be allowed for freight, transportation, insurance, shipping, storage, handling, demurrage, cartage, packaging or similar charges unless provided for in the applicable Purchase Order or otherwise agreed to in writing by Buyer;

c) Time is of the essence with respect to delivery of the goods and performance of the services. Goods shall be delivered, and services performed by the applicable delivery date. Supplier must immediately notify Buyer if Supplier is likely to be unable to meet a delivery date. At any time prior to the delivery date, Buyer may, upon notice to Supplier, cancel or change a Purchase Order or any portion thereof for any reason including, without limitation, for the convenience of Buyer, or due to failure of Supplier to comply with this Agreement unless otherwise noted;

d) Title and risk of loss damage shall pass to Buyer upon receipt of the goods at the delivery point unless otherwise agreed to by Buyer in writing. Buyer has no obligation to obtain insurance while goods are in transit from Supplier to delivery point;

e) Supplier shall follow all instructions of Buyer and co-operate with Buyer's customs broker as directed by Buyer (including by providing requested shipping documentation) with respect to all goods that originate from sources or suppliers based outside Canada. Supplier shall comply with all the requirements of the Canada Border Service Agency (or any successor organization) with respect to the importation of goods from outside Canada.

4. Inspection, Acceptance and Rejection

a) All shipments of goods and performance of services shall be subject to Buyer's right of inspection. Buyer shall have ninety (90) days (the inspection period) following the delivery of the goods or services at the delivery point or performance of the services to undertake such inspection and upon such inspection, Buyer shall either accept the goods or services (acceptance) or reject them. Buyer shall have the right to reject any goods that are delivered in excess of the quantity ordered or are damaged or defective. In addition, Buyer shall have the right to reject any goods or services that are not in conformance with the specifications or any term of this Agreement. Transfer of title to Buyer of goods shall not constitute Buyer's acceptance of those goods. Buyer shall provide Supplier with the inspection period notice of any goods or services that are rejected together with the reasons for such rejection. If Buyer does not provide Supplier with any notice of rejection within the inspection period, then Buyer will be deemed to have provided acceptance of such goods or services. Buyer's inspection, testing or acceptance or use of the goods or services hereunder, shall not limit or otherwise affect Supplier's warranty obligations hereunder with respect to the goods or services and such warranties shall survive inspection, tests, acceptance and use of the goods or services;

b) Buyer shall be entitled to return rejected goods to Supplier at Supplier's expense and risk of loss for, at Buyer's option, either:

   i) Full credit or refund of all amounts paid by Buyer to Supplier for the rejected goods; or,

   ii) Replacement goods to be received within the time period specified by Buyer.

Title to rejected goods that are returned to Supplier shall transfer to Supplier upon such delivery and such goods shall not be replaced by Supplier except upon written instructions from Buyer. Supplier shall not deliver goods that were previously rejected on grounds of non-compliance with this Agreement unless delivery of such goods is approved in advance by Buyer and is accompanied by a written disclosure of Buyer's prior rejection(s).

5. Price Payment Terms

Prices for the goods and/or services will be set out in the Purchase Order. Prices increases or changes not expressly set out in the Purchase Order shall not be effective unless agreed to in writing in advance by Buyer. Supplier will issue all invoices on a timely basis. All invoices delivered by Supplier must meet Buyer's requirements and at a minimum, shall reference the applicable Purchase Order. Buyer will pay the undisputed portion of properly rendered invoices thirty-five (35) days from the invoice date. Buyer shall have the right to withhold payment of any invoiced amounts that are disputed in good faith until the parties reach an agreement with respect to such disputed amounts and such withholding of disputed amounts shall not be deemed a breach of this Agreement nor shall any interest be charged on such amounts. Notwithstanding the foregoing, Buyer agrees to pay the balance of the undisputed amounts on any invoice that is the subject of any dispute within the time periods specified therein.

6. Taxes

Unless otherwise stated in a Purchase Order, all prices and other payments stated in the Purchase Order are exclusive of any taxes. Supplier shall separately itemize all applicable taxes on each invoice and indicate on each invoice, its applicable tax registration number or numbers. Buyer will pay all applicable taxes to Supplier when the applicable invoice is due. Supplier will remit all applicable taxes to the applicable government authority as required by applicable laws. Notwithstanding any other provision of this Agreement, Buyer may withhold from all amounts payable to Supplier, all applicable withholding taxes and to remit those taxes to the applicable governmental authorities as required by applicable laws.

7. Hazardous Materials

Supplier agrees to provide as requested by Buyer, to satisfy any applicable laws governing the use of any hazardous substances, either of the following:

a) All reasonably necessary documentation to verify the material composition, on a substance by substance basis, including quantity, use of each substance and any goods and/or of any process used to make, assemble, use, maintain or repair any goods; or,

b) All reasonably necessary documentation to verify any goods and/or any process used to make, assemble, use, maintain or repair any goods, do not contain and the services do not require the use of, any particular hazardous substances specified by Buyer.

8. Legal Compliance

In carrying out its obligations under the Agreement, including the performance of services, Supplier shall, at all times, comply with all applicable federal, provincial and municipal laws, regulations, standards and codes.

All equipment provided for the construction or repair of the electrical distribution system must meet the requirements of Ontario Regulation 22/04. This requirement can be met by electrical equipment that is approved in accordance with the requirements of the Ontario Electrical Safety Code Rule 2-024 (CSA Certified or equivalent). Alternative equipment approval requirements are outlined in O. Reg. 22/04.

All non-distribution type electrical equipment (ancillary equipment) must be approved in accordance with the requirements of the Ontario Electrical Safety Code Rule 2-024.

Any item not meeting the above two requirements will be returned at the Supplier's expense.

9. Warranties

a) Product Warranties

Supplier warrants to Buyer that during the goods warranty period, all goods provided hereunder, shall be:

i) Of merchantable quality;

ii) Fit for the intended purposes;

iii) Unless otherwise agreed to by Buyer, new;

iv) Free from defects in design, material and workmanship;

v) In strict compliance with the specifications;

vi) Free from any liens or encumbrances on title whatsoever;

vii) In conformance with any samples provided to Buyer; and,

viii) Compliant with all applicable federal, provincial, and municipal laws, regulations, standards and codes.

b) **Service Warranties**

Supplier shall perform all services:

i) Exercising that degree of professionalism, skill, diligence, care, prudence, judgment, and integrity which would reasonably be expected from a skilled and experienced service provider, providing services under the same or similar circumstances as the services under this Agreement; and,

ii) In accordance with all specifications and all Buyer polices, guidelines, by-laws and codes of conduct applicable to Supplier; and,

iii) Using only personnel with the skills, training, expertise and qualifications necessary to carry out the services. Buyer may object to any of the Supplier’s personnel engaged in the performance of services who, in the reasonable opinion of Buyer, are lacking an appropriate skill or qualification, engage in misconduct, constitute a safety risk or hazard or are incompetent or negligent, and, Supplier shall promptly remove such personnel from the performance of any services upon receipt of such notice and shall not re-employ the removed person in connection with the services without the prior written consent of Buyer.

c) **Intellectual Property Warranty**

Supplier further warrants to Buyer that at all times, all goods and/or services including deliverables, will not be in violation of, or infringe any intellectual property rights of any person.

d) **Manufacturer Warranties**

Supplier shall assign to Buyer, all manufacturer’s warranties for goods not manufactured by or for, Supplier, and shall take all necessary steps as required by such third party manufacturers, to effect assignment of such warranties to Buyer.

10. Warranty Remedies

a) In the event of breach of the warranties in section 9 and without prejudice to any other right or remedy available to Buyer, (including Buyer’s indemnification rights hereunder), Supplier will, at Buyer’s option, and Supplier’s expense, refund the purchase price for, or correct or replace the affected goods or re-perform the affected services within ten (10) days after notice by Buyer to Supplier of breach of warranty. All associated costs, including costs of reperformance, costs to inspect the goods and/or services, transport the goods from Buyer to Supplier and return shipment to Buyer and costs resulting from supply chain interruptions, will be borne by Supplier. If goods are corrected or replaced, or services are re-performed, the warranties in section 9 will continue as to the corrected or replaced goods for a further goods warranty period commencing on the date of acceptance of the corrected or replaced goods by Buyer. If Supplier fails to repair or replace the product within the time periods set out herein, Buyer may repair or replace the goods at Supplier's expense;

b) In the event that any goods provided by Supplier to Buyer are subject to a claim or allegation of infringement of intellectual property rights of a third party, Supplier shall, at its own option and expense, without prejudice to any other right or remedy of Buyer, (including Buyer's indemnification rights hereunder) promptly provide Buyer with a commercially reasonable alternative including the procurement for Buyer of the right to continue using the goods in question, the replacement of such goods with a non-infringing alternative satisfactory to Buyer or the modification of such goods (without affecting functionality), to render them non-infringing.

11. Intellectual Property Rights

All intellectual property rights in and to each deliverable, shall vest in Buyer free and clear of all liens and encumbrances on receipt of payment by Supplier for each deliverable. To the extent that any deliverables contain any intellectual property of Supplier, Supplier hereby grants to Buyer a worldwide, royalty free, non-exclusive, perpetual license to use, copy, modify, and distribute such intellectual property as part of the deliverables. Supplier agrees to provide Buyer all assistance, reasonably requested by Buyer, to perfect the rights described herein including obtaining all assignments and waivers of moral rights necessary, or appropriate, to vest the entire right, title and interest in such materials in Buyer and its accessors and assigns.

12. Confidentiality

Supplier acknowledges that Buyer is bound by the provisions of the *Municipal Freedom of Information and Protection of Privacy Act* and regulations thereto. Supplier shall safeguard and keep confidential, any and all information relating to Buyer obtained by it or provided to it by Buyer, in connection with this Agreement and shall use such information only for the purpose of carrying out its obligations under this Agreement.

13. Insurance

Supplier represents and warrants to Buyer that it has in place, with reputable insurers, such insurance policies in coverage amounts that would be maintained by a prudent supplier of goods and services similar to the goods and services provided hereunder, including, as applicable, professional errors and omissions, liability insurance and comprehensive, commercial general liability insurance (including product liability coverage, all risk contractors, equipment insurance and automobile liability insurance). In addition, Supplier will take out and maintain at its own cost, such insurance policies and coverages as may be reasonably required by Buyer from time to time. Supplier will promptly deliver to Buyer, as and when requested, written proof of such insurance. If requested, Buyer will be named as an additional insured under any such policies. If requested by Buyer, such insurance will provide that it cannot be cancelled or materially changed so as to affect the coverage provided under this Agreement, without the insurer providing at least thirty (30) days prior written notice to Buyer.

14. Indemnities

Supplier shall indemnify, defend and hold harmless Buyer, its affiliates and their respective officers, directors, employees, consultants and agents (the Buyer indemnified parties) from and against any claims, fines, losses, actions, damages, expenses, legal fees and all other liabilities brought against, or incurred by Buyer, indemnified parties or any of them, arising out of:

a) Death, bodily injury or loss, or damage to real or tangible personal property resulting from the use of, or any actual or alleged defect in the goods or services, or from the failure of the goods or services to comply with the warranties hereunder;

b) Any claim that the goods or services infringe or violate the intellectual property rights or other rights of any person;

c) Any intentional, wrongful or negligent act or omission of Supplier or any of its affiliates or sub-contractors;

d) Supplier's breach of any of its obligations under this Agreement;

e) Any liens or encumbrance relating to any goods or services.

15. Limitation of Liability

Except for Supplier's obligation under section 14, and except for damages that are the result of the gross negligence or willful misconduct of a party, in no event will either party be liable to the other party or any other person for any direct, incidental, consequential, or punitive damages including any lost profits, data, goodwill, or business opportunity for any matter relating to this Agreement.

16. Independent Contractors

Supplier will perform its obligations under the Agreement as an independent contractor and in no way will Supplier or its employees, be considered employees, agents, partners, fiduciaries or joint venturers of Buyer. Supplier and its employees will have no authority to represent Buyer or its affiliates or bind Buyer or its affiliates in any way and neither Supplier nor its employees will hold themselves out as having authority to act for Buyer or its affiliates.

17. Further Assurances

The parties shall assign such further and other documents, cause such meetings to be held, resolutions passed, and do and perform, and cause to be done and performed, such further and other acts and things as may be necessary or desirable in order to give full effect to this

Agreement and every part thereof.

18. Severability

If any provision of this Agreement is determined to be unenforceable or invalid by any reason whatsoever in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof, and the remaining part thereof, and all other provisions shall continue in force and effect.

19. Waiver

No waiver of any provision of this Agreement shall be enforceable against that party unless it is in writing and signed by that party.

20. Assignment

Supplier may not assign or sub-contract this Agreement in whole or in part without Buyer's prior written consent. Supplier's permitted assignment or sub-contracting of this Agreement, or any part thereof, will not release Supplier of its obligations under this Agreement and it will remain jointly and severally liable with the assignee or sub-contractor for any obligations assigned or sub-contracted. The acts or omissions of any sub-contractors of Supplier will be deemed to be the acts and omissions of Supplier. Buyer may assign this Agreement in whole or in part to any affiliate or buyer without the consent of Supplier. This Agreement shall enure to the benefit of, and be binding upon, the parties and their respective representatives, heirs, executors, administrators, assigns or successors.

21. Survival

Any provision of this Agreement which expressly or the implication from its nature is intended to survive the termination or completion of the Agreement, will continue in force and full effect after any termination, expiry or completion of this Agreement.

22. Governing Law

This Agreement shall be governed by the laws of the Province of Ontario and the federal laws of Canada applicable therein. The parties irrevocably attorn to the jurisdiction of the Courts of Ontario which will have non-exclusive jurisdiction over any matter arising out of this Agreement.

Appendix G – Live Excel Models – Staff-120

Appendix H – SSG DVA Accounting Order

PUC Distribution Inc.

2023 Cost of Service Application – The Sault Smart Grid Project
Forgone Revenue Requirement

EB-2022-0059

Accounting Order

Account 1508 Other Regulatory Assets

Sub-accounts SSG Foregone Revenue Requirement

December 12, 2022

PUC Distribution Inc. - 2023 Cost of Service Application – The Sault Smart Grid Project Foregone Revenue Requirement

Accounting Order – Account 1508 Other Regulatory Assets

This account is intended to ensure PUC remains whole; therefore, PUC is proposing to record the difference in revenue requirement associated with the SSG included in base distribution rates less the revenue requirement associated with the SSG adjusted to reflect full year in-service for the years beyond 2023 to 2027.

This account shall be treated as a Group 1 DVA account and the balance in this account will be disposed of annually with PUC's IRM filings.

The following describes the sub account and sample journal entries for the new account.

1) Account 1508 Other Regulatory Assets, Sub-account SSG Forgone Revenue Requirement

This account shall be used to record the change in revenue requirement as a result of the calculating at the full-year in-service value of the Sault Smart Grid Assets.

2) Account 1508 Other Regulatory Assets, Sub-account SSG Forgone Revenue Requirement Carrying Charges

Carrying charges calculated on the year-end balance shall be recorded in this sub account. Carrying charges shall be calculated using simple interest applied to the opening balances in the account and shall be recorded monthly in a separate carrying charges sub account. The interest rate shall be the rate prescribed by the Board.

A sample of the accounting entries associated with foregone revenue requirement is presented below.

1508 – Other Regulatory Assets – SSG Foregone Revenue Requirement	$XX	
4080 Distribution Revenue		$XX
1508 – Other Regulatory Assets – SSG Foregone Revenue Requirement Carrying costs	$XX	
4405 Carrying costs		$XX

To record the associated difference in revenue requirement related to full-year in-service additions of the SSG project.

Disposition of Accounts

PUC requests to include the balance in this account in its annual IRM filing disposition request.

Appendix I – Evidence Updates

John Vellone
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Borden Ladner Gervais

File No. 14898.17

December 11, 2022

<u>BY EMAIL</u>
Without Prejudice and Confidential

Karen Wianecki
Planning Solutions Inc.
8 Buggey Lane
Ajax, ON L1Z1X4

Dear Ms. Wianecki

Re: PUC Distribution Inc. ("PUC")
Application for 2023 Electricity Distribution Rates
Ontario Energy Board ("OEB") File No. EB-2022-0059 ("Proceeding")

Please find enclosed the Pre-Settlement Clarification Responses of PUC in respect of the above noted Proceeding. We note that a new accounting order is attached to the Pre-Settlement Clarification Responses as "Appendix F". This accounting order is related to the foregone revenue for Sault Smart Grid in years 2024-2027 from the half-year accounting on asset completions that are carried over into 2023.

PUC is also revising certain portions of its filed evidence and interrogatory responses as a result of the Pre-Settlement Clarification Responses. Appendix A to this letter outlines these changes.

Please contact the undersigned with any questions.

Yours truly,

J Vellone

John Vellone

cc: Interveners in EB-2022-0059

Appendix A

Updates to Evidence and Interrogatory Responses

As a result of the responses to the Pre-Settlement Clarification Questions, PUC revised the following evidence filed on the record of the Proceeding:

1. Staff 114 – PUC has updated the Chapter 2 Appendices 2-ZA and 2-ZB to reflect the revised consumption in the final load forecast model (VECC 55). Additionally the OER was updated to 11.7%.

2. Staff 119 – The DVA continuity schedule has been updated to reflect the proper amount of depreciation and accumulated depreciation for the ICM Substation 16 sub accounts. There was $75,251 depreciation in 2021 and $150,503 in 2022 for a revised total of $225,754. The revised model filed on November 28, 2022 still had a value of $275,922.

3. Staff 120b(iv) – The DVA continuity schedule has been reflected to revised amount of rate rider revenue to be collected from customers. PUC also added row 67 which shows the revised rate rider revenue calculation from the ICM true up calculation. This results in a net refund to customer of $51,941 (includes carrying charges) for Group 2 Substation 16 ICM.

4. Staff 126 – The Chapter 2 Appendices, App-2H has been updated throughout entire sheet to show the updated building return charges and pole attachment revenue.

5. Staff 127 – PUC has revised the CCA rate for the Omicron Injection Tester to 20% since it falls under Class 8. This change has caused an update throughout all the models due to the CCA smoothing calculation and the resulting Loss Carry Forward Rate Rider amount.

6. Staff 128 – PUC has revised tabs 5 and 6 of the Tariff Schedule and Bill Impact model to reflect all updates for RPP rates, pole attachment, Smart metering entity charges and retail service charges.

7. Staff 133 – The DVA Continuity Schedule, Account 1588 and 1589 GL Activity and principal adjustments have been updated to reflect the $759,501 and $(759,501) respectively. The GA Workform has been updated to agree the 1588 principal adjustment to the Principal Adjustments tab, as well the transactions for 2021 has also been updated (previously only showed the 2021 activity and not the 2020 adjustment). The GA 2022 Net Change in Principle Balance has also been updated to agree to the DVA Continuity 2021 transactions.

8. VECC 55 – The customer count has been properly removed as an explanatory variable in the load forecast.

9. VECC 56 – the load forecast has been updated for the final CDM adjustment factor as explained in the response to VECC 56.

Further as a result of the responses to the Pre-Settlement Clarification Questions, PUC is providing the following list of revisions to correct the information filed in the Interrogatory Responses on

November 28, 2022. These revisions have been reflected in the appropriate OEB Models that have been filed with these Pre-Settlement Clarification Questions.

1. SEC 9 – Table 2-25 has been revised for the final revenue requirement reconciliation that PUC is submitting for this settlement proposal. PUC is proposing to refund customer an over collection of $53,779 based on the ICM true up calculation of $275,864 in revenue requirement in year 1 (2021) which uses the half year rule and $356,932 in year 2 (2022) which uses a full year.

	2020	2021	2022	Total
Approved Revenue Requirement ($4.73M)	$213,870	$237,816	$237,816	$689,502
Revised Revenue Requirement ($6.02M)		$275,864	$356,932	$632,796
Projected Revenue Collection to April 30, 2023	$275,744	$281,162	$129,669	$686,575
			Refund (-) or Collection	**$ (53,779)**

2. PUC has revised its 2022 and 2023 in service additions for SSG. The updated spending amounts can be viewed in the response to CCC-55.

3. SEC 19 – PUC has revised the Chapter 2 Appendices 2-AA and 2-AB 2022 YTD column to include the capital expenditures as of October 31, 2022 for SSG Assets.

4. PUC has revised the pole attachment rate used as outlined in VECC 57a. This has reduced the revenue offsets by $19,569.

5. VECC 53 – Table 1-12 Deferral and Variance Accounts, Table 1-13 DVAs Commence / Continues / Discontinue and Exhibit 9 Tables have been updated as per the updates made to the DVA Continuity Schedule.

6. STAFF 102, 108 and 109 – PUC has revised the DVA Continuity Schedule Account 1588 and 1589 and the GA Workform as outlined in Staff 133.

7. PUC has removed the effects of 2023 SSG asset additions from the CCA smoothing adjustment in the calculation of revenue requirement. All changes in revenue requirement, including the CCA smoothing adjustment, in relation to SSG asset additions will be captured in the newly proposed DVA account attached as Appendix F.

SCHEDULE B

DECISION AND ORDER

TARIFF OF RATES AND CHARGES

PUC DISTRIBUTION INC.

EB-2022-0059

APRIL 6, 2023

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	38.35
Rate Rider for Disposition of Account 1509 - COVID (2023) - effective until April 30, 2024	$	0.54
Rate Rider for Disposition of Group 2 Accounts (2023) - effective until April 30, 2024	$	(0.65)
Rate Rider for Disposition of Tax Loss Carry-forward (2023) - effective until April 30, 2024	$	(0.98)
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	2.14
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until April 30, 2024	$/kWh	0.0002
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - effective until April 30, 2024	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0092

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	22.32
Rate Rider for Disposition of Account 1509 - COVID (2023) - effective until April 30, 2024	$	1.23
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	1.25
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate	$/kWh	0.0319
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kWh	0.0018
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until April 30, 2024	$/kWh	0.0003
Rate Rider for Disposition of Tax Loss Carry-forward (2023) - effective until April 30, 2024	$/kWh	(0.0010)
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - effective until April 30, 2024	$/kWh	(0.0013)
Rate Rider for Disposition of Group 2 Accounts (2023) - effective until April 30, 2024	$/kWh	(0.0009)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

EB-2022-0059

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. Class A and Class B consumers are defined on accordance with O. Reg. 429/04. 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.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	123.27
Rate Rider for Disposition of Account 1509 - COVID (2023) - effective until April 30, 2024	$	17.87
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	6.88
Distribution Volumetric Rate	$/kW	8.3565
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kW	0.4601
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until April 30, 2024	$/kW	0.1195
Rate Rider for Disposition of Tax Loss Carry-forward (2023) - effective until April 30, 2024	$/kW	(0.2240)
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0540)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - effective until April 30, 2024	$/kW	0.4587
Rate Rider for Disposition of Group 2 Accounts (2023) - effective until April 30, 2024	$/kW	(0.4159)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kW	3.4567
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	4.3474

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

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EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	13.67
Rate Rider for Disposition of Account 1509 - COVID (2023) - effective until April 30, 2024	$	2.15
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	0.76
Distribution Volumetric Rate	$/kWh	0.0476
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kWh	0.0027
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until April 30, 2024	$/kWh	0.0003
Rate Rider for Disposition of Tax Loss Carry-forward (2023) - effective until April 30, 2024	$/kWh	(0.0013)
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of Group 2 Accounts (2023) - effective until April 30, 2024	$/kWh	(0.0009)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2023
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EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.35
Rate Rider for Disposition of Account 1509 - COVID (2023) - effective until April 30, 2024	$	0.15
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	0.24
Distribution Volumetric Rate	$/kW	40.6108
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kW	2.2678
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until April 30, 2024	$/kW	0.1012
Rate Rider for Disposition of Tax Loss Carry-forward (2023) - effective until April 30, 2024	$/kW	(1.7931)
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0462)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kW	0.4597
Retail Transmission Rate - Network Service Rate	$/kW	2.6202

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

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EB-2022-0059

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. Class B consumers are defined on accordance with O. Reg. 429/04. 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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.67
Rate Rider for Disposition of Account 1509 - COVID (2023) - effective until April 30, 2024	$	0.04
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$	0.09
Distribution Volumetric Rate	$/kW	10.9378
Rate Rider for Recovery of SSG Project Recovery (2023) - effective until April 30, 2024	$/kW	0.6108
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until April 30, 2024	$/kW	0.1010
Rate Rider for Disposition of Tax Loss Carry-forward (2023) - effective until April 30, 2024	$/kW	(0.8559)
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0461)
Rate Rider for Disposition of Group 2 Accounts (2023) - effective until April 30, 2024	$/kW	0.9718
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kW	2.6073

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment - effective until	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0007
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2023
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EB-2022-0059

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.

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.

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 Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

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EB-2022-0059

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.

No 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.

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 Global Adjustment and the HST.

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 (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection charge - at meter - during regular hours	$	65.00
Reconnection charge - at meter - after hours	$	185.00
Reconnection charge - at pole - during regular hours	$	185.00
Reconnection charge - at pole - after hours	$	415.00

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 (with the exception of wireless attachments)	$	36.05
Removal of overhead lines - during regular hours		Time & Materials
Removal of overhead lines - after hours		Time & Materials
Roadway escort - after regular hours		Time & Materials

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

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EB-2022-0059

RETAIL SERVICE CHARGES (if applicable)

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.

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 Global Adjustment and the HST.

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	$	111.66
Monthly fixed charge, per retailer	$	44.67
Monthly variable charge, per customer, per retailer	$/cust.	1.11
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.66
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.66)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.56
Processing fee, per request, applied to the requesting party	$	1.11
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)	$	4.47
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.23

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	1.0462
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0357

SCHEDULE C

DECISION AND ORDER

ACCOUNTING ORDER - SAULT SMART GRID PROJECT VVO

LINKAGE TO ROE

PUC DISTRIBUTION INC.

EB-2022-0059

APRIL 6, 2023

PUC Distribution Inc. - 2023 Cost of Service Application – Sault Smart Grid Project VVO Linkage to ROE

Accounting Order

Account 1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings

As part of the Ontario Energy Board's ("OEB") decision on the Sault Smart Grid ("SSG") project (EB-2018-0219/EB-2020-0249), PUC Distribution Inc. ("PUC") was required to file all available information on the proposed SSG performance metrics that it intends to track, along with proposed targets, in its next rebasing application. The OEB required PUC to include an appropriate metric and targets to symmetrically link the Voltage / VAR Optimization ("VVO") performance of SSG to PUC's allowable Return on Equity ("ROE") for this Project. PUC proposed and the Parties agreed to do this through the use of Account 1508 – Other Regulatory Assets, Sub Account Incremental VVO Costs or Savings. The sub-account will record incremental VVO savings or costs to customers in a given year. The following describes the calculation of the VVO % savings to ROE linkage and includes the corresponding sample journal entries for the sharing of incremental savings or costs to customers.

This sub-account will have an effective date of May 1, 2023.

<u>**VVO Link to ROE**</u>

As identified in its SSG ICM Application, PUC's target is to achieve 2.70% VVO savings. If PUC achieves VVO savings that is above or below this target, it will symmetrically collect or refund or the percentage difference on its ROE for the SSG Project in that respective year using the following formula:

$$\text{Debit/Credit} = \frac{AVS - TVS}{TVS} \times SSGROE$$

Variables:

- AVS means the actual VVO energy savings achieved (expressed as a percentage of energy consumption) from the SSG project over a given calendar year.

- TVS means the targeted VVO savings from the SSG project, which shall be fixed at 2.70%.

- SSGROE means the return on equity component of revenue requirement of the SSG project in a calendar year as set out in Table 1 below.

Table 1: SSGROE Values Between 2023 and 2027

Year	Return on Base – Equity (SSGROE)
2023	$614,958
2024	$883,842
2025	$858,097
2026	$832,352
2027	$806,606

The ROE Revenue Requirement of the SSG project will be determined using the project reconciliation amounts that PUC is required to provide as part of its next rebasing application consistent with the SSG Project Recovery Mechanism. The cost of capital parameters used to calculate ROE shall be those that are used as part of the SSG Project Recovery Mechanism model filed with PUC's Settlement Proposal for its 2023 Cost of Service Rate application (EB-2022-0059). An example of the calculation is provided in Table 1 above. The ROE values in Table 1 are for illustrative purposes only. The ROE values used in the calculation will be based on the lower i) actual SSG Project capital costs and in-service dates, and ii) and the settled amount used to calculated the SSG Recovery Mechanism Rate Rider.

Table 2 VVO Over/Under Target Scenarios[1]

	Over VVO Target	Under VVO Target
ROE	$750,000	$750,000
VVO %Target	2.70%	2.70%
VVO %Result	3.00%	2.40%
delta	11.11%	-11.11%
Refund/Collection	$83,333	($83,333)

1 – These numbers are for illustration purposes only. The actual amount will vary given the VVO kWh savings and ROE amount from year to year.

The scenarios in Table 2 result in either a debit (collection) from customer or a credit (refund) to customers. A sample of corresponding journal entries is provided in Table 3 below.

Table 3 – Accounting Entries for VVO Over/Under Target Scenarios[1]

VVO Result 2.40%		
4080 Distribution Revenue	$83,333	
1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings		$83,333
to record the increase in savings to PUC customers		

VVO Result 3.00%		
1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings	$83,333	
4080 Distribution Revenue		$83,333
to record the reduction in savings to PUC Customers		

1 – These numbers are for illustration purposes only. The actual amount will vary given the VVO kWh savings and ROE amount from year to year.

Additionally, PUC will apply a symmetrical maximum upside (5.4% VVO kWh savings) and downside (0% VVO kWh savings) equal to the ROE of the SSG Project.

Disposition of the Account Balance

The Parties agree that at the next rebasing application where PUC shall bring forward the sub-account for disposition, the OEB panel hearing the matter will have discretion regarding how much, if any amount, should ultimately be recorded in the account and disposed to the benefit of either PUC or customers. The parties' agreement on this matter is based on the following expected treatment of the account:

- the maximum amount that can be credited or debited for any year shall not exceed the level of the symmetrical maximum upside (5.4% VVO kWh savings) and downside (0% VVO kWh savings) for the calculated ROE for the SSG Project in accordance with the formula above. Any calculated amounts are solely related to VVO consumptions savings and all other factors (e.g., distribution automation) are excluded from this account;
- the principle of symmetrical risk/reward of this account around a targeted VVO savings of 2.70% shall be maintained to the maximum extent possible; and
- the OEB panel deciding the disposition of the account will be guided by the results of the report(s) set out in Issue 5.4 of the Settlement Proposal, and any information that arises from review of those reports.

As referenced by PUC in Clarification Question CCC-55, substantial completion of the project requires optimization and testing by Black and Veatch: (a) on a station by station basis to finalize voltage reduction settings and control systems; and (b) on full system wide basis to confirm coordinated station performance, which includes items such as integrated measurement, verification and reporting. As set out in the response to Staff-29, the testing and optimization phase of the SSG Project PUC anticipates to be in a position to start measuring VVO savings at the time of Substantial Completion. Substantial Completion is currently expected to occur November 1, 2023. On that basis, Parties have not agreed how to apply the VVO Link to ROE formula for the 2023 year (or if necessary, into 2024).

The Parties do agree that the OEB at the time of disposition of the account will address, what if any, amount for 2023 should be disposed to the benefit of ratepayers or the utility. At that time, and subject to the operation of this account, some Parties may take the position that PUC should receive no ROE for the period in which the project is not substantially complete or for any period in which the project fails to operate as expected after it becomes substantially complete.

The Parties expect that the OEB will take into account the Parties' agreement on the above noted treatment of the account when the OEB considers disposition of the account.

The continuation or discontinuation of this account shall be addressed at the time of PUC's 2028 rebasing application.

1) Account 1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings

This account shall be used to record incremental VVO costs or savings to customers when the VVO percentage is above or below the targeted 2.70% VVO savings. The savings or costs have upper and lower maximums of 5.40% and 0% respectively equalling the ROE of the SSG Project for a given year as detailed above.

2) Account 1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings Carrying Charges

Carrying charges shall be recorded monthly in this sub-account, calculated using simple interest applied to the opening balances in the Incremental VVO Costs of Savings sub-account. The interest rate shall be at the OEB's prescribed rate. The following are sample journal entries is an example for carrying charges.

6035 – Other Interest Expense

    1508 – Sub-account Incremental VVO Costs or Savings Carrying Charges

To record the carrying charges if there is a credit balance owing to customers at year end.

1508 – Sub-account Incremental VVO Costs or Savings Carrying Charges

    4405 – Interest and Dividend Income

To record the carrying charges if there is a debit balance owing from customers at year end.

SCHEDULE D

DECISION AND ORDER

ACCOUNTING ORDER - SAULT SMART GRID PROJECT

LIQUIDATED DAMAGES

PUC DISTRIBUTION INC.

EB-2022-0059

APRIL 6, 2023

PUC Distribution Inc. - 2023 Cost of Service Application – Sault Smart Grid Project Liquidated Damages

Accounting Order
Account 1508 Other Regulatory Assets,
Sub-account SSG EPC Contract Liquidated Damages

As part of the Ontario Energy Board's ("OEB") decision on the Sault Smart Grid project (EB-2018-0219/EB-2020-0249) ("SSG"), the OEB found that in order to manage the risks associated with SSG and appropriately monitor its progress, the OEB approval was subject to the following condition:

> *"Any EPC Contract liquidated damages resulting from "performance" or "delay" shall be used to reduce the project capital cost and would be settled at the time of the next rebasing."*

No liquidated damages were calculated as of the time of the 2023 Cost of Service application. This sub-account is to record the revenue requirement impact of any liquidated damages received by PUC for the SSG Project, so that the reduction to the settled upon SSG revenue requirement resulting from liquidated damages is returned to ratepayers. This sub-account will have an effective date of May 1, 2023 and will record the revenue requirement impact of any liquidated damages received related to the SSG Project even if they were received or became due before the effective date.

1) Account 1508 Other Regulatory Assets, Sub-account SSG EPC Contract Liquidated Damages

This account shall be used to record the revenue requirement impact of any liquidated damages received.

2) Account 1508 Other Regulatory Assets, Sub-account SSG EPC Contract Liquidated Damages Carrying Charges

Carrying charges shall be recorded monthly in this sub-account, calculated using simple interest applied to the opening balances in the SSG EPC Contract Liquidated Damages sub-account. The interest rate shall be at the OEB's prescribed rate.

A sample of the journal entries associated with liquidated damages is presented below.

4080 - Distribution Revenue	$XX
1508 – Sub-account SSG EPC Contract Liquidated Damages	$XX

SSG EPC Contract Liquidated Damages
To record the revenue requirement impact from liquidated damages received.

The following are sample journal entries is an example for carrying charges.

6035 – Other Interest Expense

1508 – Sub-account SSG EPC Contract Liquidated Damages

To record the carrying charges if there is a credit balance owing to customers at year end.

SCHEDULE E

DECISION AND ORDER

ACCOUNTING ORDER - SAULT SMART GRID PROJECT RECOVERY MECHANISM VARIANCE ACCOUNT

PUC DISTRIBUTION INC.

EB-2022-0059

APRIL 6, 2023

PUC Distribution Inc. - 2023 Cost of Service Application

Accounting Order

Account 1508 Other Regulatory Assets, Sub-account SSG Project Recovery Mechanism Variance Account

PUC shall establish Account 1508 – Other Regulatory Assets, Sub-account Sault Smart Grid ("SSG") Project Recovery Mechanism Variance Account and a corresponding carrying charge sub-account effective May 1, 2023.

This purpose of the sub-account is to record an asymmetrical true-up for the recovery of the SSG Project to the benefit of ratepayers for the period of May 1, 2023 to April 30, 2028. The mechanics are of this true-up are described under #1 below. PUC's net recovery for the SSG Project for this period, after considering this sub-account, will be the lower of

a) total rate riders collected from May 1, 2023 to April 30, 2028; and
b) the sum of 2023 to 2027 revenue requirements, where the annual revenue requirement is the lower of i) the recalculated revenue requirement based on actual SSG Project capital costs and in-service dates ("Actual Revenue Requirement"), and ii) the settled forecasted revenue requirement used to calculate the SSG Recovery Mechanism Rate Rider ("Settled Revenue Requirement").

This sub-account will be a Group 2 account and the balance will be requested for disposition at PUC's next Cost of Service application with carrying charges applied at the OEB's prescribed rate. The sub-account will be closed upon disposition of the balance, if any.

1) Account 1508 Other Regulatory Assets, Sub-account SSG Project Recovery Mechanism Variance Account

Annually, the lower of the Actual Revenue Requirement and the Settled Revenue Requirement will be identified ("Lower Revenue Requirement"). Once the annual Lower Revenue Requirement is identified, the Lower Revenue Requirement will be recorded in the sub-account. The rate riders collected for that year will also be recorded in the sub-account as an offset. This net effect in the sub-account will be:

- If the annual Lower Revenue Requirement is less than rate riders collected for that year, a credit amount equalling the difference between the two will be recorded in the sub-account.

- If the annual Lower Revenue Requirement is greater than rate riders collected for that year, a debit amount equalling the difference between the two will be recorded in the sub-account.

If the cumulative amount recorded in the sub-account is a credit amount on April 30, 2028, the credit amount will be returned to ratepayers. Conversely, if the cumulative amount recorded in the sub-account is a debit amount, the debit amount will not be disposed and the balance in the sub-account will not be recoverable from ratepayers and will be written off.

2) Account 1508 Other Regulatory Assets, Sub-account SSG Project Recovery Mechanism Carrying Charges

Carrying charges shall be recorded monthly in this sub-account, calculated using simple interest applied to the opening balances in the SSG Project Recovery Mechanism Variance Account sub-account. The interest rate shall be at the OEB's prescribed rate. This sub-account will be disposed of if there is a credit balance. Otherwise, the balance in the sub-account will not be disposed and the balance in the sub-account will be written off.

EXAMPLE WITH JOURNAL ENTRIES

An illustrative example with journal entries associated with the SSG Project and SSG Project Recovery Mechanism Variance Account.

1) Cost Assessment (no entry)	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**
	Actual Cost Higher Than Settlement Cost					
Settled Revenue Requirement	1,000	1,000	1,000	1,000	1,000	5,000
Actual Revenue Requirement	700	700	700	700	700	3,500
Lower of Settled or Actual Rev Requirement	700	700	700	700	700	3,500

2) Over collection True-Up Asymmetrical on Aggregate Basis entry	**2023**	**2024**	**2025**	**2026**	**2027**	**Total 2023 to 2027**
	Collected More Than Settled Rev Requirement in Total					
Rate Riders Collected	800	500	1200	600	1300	4,400
Lower of Settled and Actual Rev Requirement	700	700	700	700	700	3,500
Account 1508	- 100	200	- 500	100	- 600	- 900 Refund

PUC Actual Total Recovery	3,500

Sample cumulative journal entries that will be recorded annually:

1180 – Accounts Receivable/1005 – Cash	$4,400	
1508 – Other Regulatory Assets – SSG Project Recovery Mechanism Variance Account		$4,400

To record the SSG Recovery Mechanism Rate Rider received, for SSG Revenue Requirement

1508 – Other Regulatory Assets – SSG Project Recovery Mechanism Variance Account	$3,500	
4080 – Distribution Revenue		$3,500

To record the annual “Lower Revenue Requirement” for SSG Revenue Requirement

6035 – Other Interest Expense	$xx	
1508 Other Regulatory Assets, SSG Project Recovery Mechanism Carrying Charges		$xx

To record carrying charges on a credit balance in the DVA.

1508 – Other Regulatory Assets, SSG Project Recovery Mechanism Carrying Charges	$xx	
4405 – Interest and Dividend Income		$xx

To record carrying charges on a debit balance in the DVA.