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

PARTIAL DECISION AND ORDER

EB-2024-0007

ALGOMA POWER INC.

Application for electricity distribution rates and other charges beginning January 1, 2025

BEFORE: Allison Duff
Presiding Commissioner

Fred Cass
Commissioner

November 19, 2024

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1 OVERVIEW

On June 3, 2024, Algoma Power Inc. (Algoma Power) filed a cost-of-service application seeking approval for changes to the rates that Algoma Power charges for electricity distribution, beginning January 1, 2025.

As part of its application, Algoma Power requested an order requiring the Independent Electricity System Operator (IESO) to resettle prior period Class A consumption adjustments for May 2021 and January 2022. The OEB decided to exclude the issue pertaining to this request as well as the disposition of the commodity Accounts 1588 and 1589 (Issue 6.2) from the set of issues eligible for a settlement.[1]

A settlement conference was held as part of this proceeding to address the remainder of the application. This is a Partial Decision and Order regarding the Settlement Proposal, which was filed by Algoma Power on October 25, 2024. The Settlement Proposal reflects a settlement between Algoma Power, School Energy Coalition (SEC), Vulnerable Energy Consumers Coalition (VECC) and the Independent Electricity System Operator (IESO) (collectively, the Parties) on all issues included on the approved Issues List except Issue 6.2.[2] A decision on Issue 6.2 will be issued in due course.

For the reasons set out in this Partial Decision and Order, the OEB approves the Settlement Proposal as filed (attached as Schedule A). The OEB concludes that the Settlement Proposal will result in just and reasonable rates for customers of Algoma Power.

[1] Decision on Issues List, August 2, 2024
[2] *Ibid*, p. 2

2 PROCESS

The OEB's *Renewed Regulatory Framework for Electricity*[3] and *Handbook for Utility Rate Applications*[4] 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.

On June 3, 2024, Algoma Power filed a cost of service application with the OEB under section 78 of the *Ontario Energy Board Act, 1998*. The application requested OEB approval of Algoma Power's proposed electricity distribution rates for five years, using the Price Cap Incentive Rate-setting (Price Cap IR) option described in the *Renewed Regulatory Framework for Electricity*. Under the Price Cap IR option, with an approved 2025 Test Year, Algoma Power would be eligible to apply to have its 2026-2029 rates adjusted mechanistically, based on inflation and the OEB's assessment of Algoma Powers' efficiency.

The application was accepted by the OEB as complete on June 17, 2024. The OEB issued a Notice of Hearing on June 27, 2024, inviting parties to apply for intervenor status. SEC, VECC and the IESO were granted intervenor status. SEC and VECC applied for and were granted eligibility for cost awards.

The OEB issued Procedural Order No. 1 on July 22, 2024. This order established, among other things, the timetable for a written interrogatory discovery process and a settlement conference.

OEB staff filed a proposed Issues List that had been agreed to by all Parties for the OEB's consideration on July 29, 2024. The OEB approved a revised Issues List on August 2, 2024. The OEB determined that Issue 6.2 was ineligible for settlement and would be heard via a written hearing process.

During the discovery process, Algoma Power responded to interrogatories and follow-up questions submitted by OEB staff and intervenors.

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[3] Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012
[4] Handbook for Utility Rate Applications, October 13, 2016

A settlement conference was held September 18, 19, 20, 23, 24 and 25, 2024. Algoma Power, SEC, VECC and the IESO participated in the settlement conference. OEB staff attended the conference but was not a party to the settlement. Algoma Power filed a Settlement Proposal on all eligible issues on October 25, 2024. The IESO was a party to the settlement, however the IESO neither supported nor opposed any elements of this Settlement Proposal and took no position on the issues addressed in the Settlement Proposal.

OEB staff filed a submission supporting the Settlement Proposal on November 5, 2024.[5]

[5] OEB staff submission on the Settlement Proposal

3 DECISION ON THE SETTLEMENT PROPOSAL

The Settlement Proposal represents a settlement on all the issues except for the excluded Issue 6.2.[6]

Key elements of the Settlement Proposal, compared to the application, are as follows:

- A net increase of $600k to the 2024 capital in-service additions resulting in a revised budget of $14.3M,[7] and a net increase of $2.2M to the 2025 capital in-service additions resulting in a revised budget of $12.4M
- Net in-service additions to the 2025 opening rate base of $15.9M for the Sault St. Marie Facility advance capital module (ACM) and $10.7M for the Echo River TS ACM
- Reduction to 2025 OM&A expenses of $970k
- ACM True-up amount of $1.3M (excluding CCA changes) for 2025 rates
- Base revenue requirement of $33.7M for 2025, a reduction of $451k (4%)
- Disposition of the Group 1 DVAs credit balance (excluding Account 1588 and 1589) of $224,727
- Disposition of the Group 2 DVAs credit balance of $1,885,219
- Establishment of the three new DVA sub accounts entitled: Defined Benefit Pension Plan Variance Account, Circuit Section C-E Sale Deferral Account and Land Use Revenue Requirement Variance Account

Findings

The OEB approves the Settlement Proposal (attached as Schedule A). The OEB has considered the provisions of the Settlement Proposal and, in particular, the key elements of the Settlement Proposal set out above. In the exercise of its statutory authority to fix or approve just and reasonable rates under section 78 of the OEB Act, and in the context of the statutory objectives set out in section 1 of the OEB Act, the OEB finds that the provisions of the Settlement Proposal will result in reasonable outcomes for Algoma Power and its customers.

[6] Issues 6.2 is being heard by a written hearing.
[7] The budget is inclusive of work completed in 2024 for two Advanced Capital Module (ACM) projects.

On the evidence in this proceeding, the OEB finds that the provisions of the settlement on all eligible issues will enable Algoma Power to operate its distribution system safely and reliably.

In approving the Settlement Proposal, the OEB acknowledges the following filing commitments made by Algoma Power for inclusion in its next rebasing application:

- an updated Asset Condition Assessment and a report on the steps it has taken to address the data gaps identified by METSCO in its previous Asset Condition Assessments.
- project cost variance reports for any capital project with an estimate of $1.5M or over during the rate term that has a cost variance of 10% or greater.
- a description and explanation of its Project Management process in its Distribution System Plan and any modification or improvements made over the rate term.
- a description of its project estimating process and any modification or improvements made over the rate term.

The OEB approves the creation of the three new DVAs and accounting orders as filed (attached as Schedules B, C and D). The OEB finds that eligibility criteria of materiality, causation and need have been met. The prudence of costs recorded in these three DVAs will be assessed at the time of disposition of any balances in these accounts.

- Account 1508 – Sub-account Defined Benefit Pension Plan Variance Account
- Account 1508 – Sub-account #4 Circuit Section C-E Sale Deferral Account
- Account 1508 – Sub-account Land Use Revenue Requirement Variance Account

A decision on Issue 6.2 pertaining to Group 1 DVAs 1588 and 1589 will be issued separately.

4 IMPLEMENTATION

The approved effective date for new rates is January 1, 2025 as agreed by the Parties.

In the Settlement Proposal, the Parties agreed that Algoma Power would provide updates upon the OEB's issuance of the following:

- 2025 Cost of Capital parameters (return on equity and deemed short-term debt rate)[8]
- Retail Service Transmission rates to reflect updated final or preliminary Uniform Transmission Rates.[9]

These two items have been issued by the OEB and, accordingly, Algoma Power shall file a draft rate order, updating the placeholder values for the components noted, with detailed supporting material showing the impact of any required adjustments.

The OEB will make provision for cost-eligible intervenors to file their cost claims in its final rate order.

[8] Settlement Proposal, p. 22 and OEB letter, 2025 Cost of Capital Parameters, October 31, 2024
[9] Settlement Proposal, p. 33 and OEB letter, 2025 Preliminary Uniform Transmission Rates and Hydro One Sub-transmission Rates, November 1, 2024

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The Settlement Proposal attached as Schedule A is approved.

2. Algoma Power shall file with the OEB and forward to intervenors a draft rate order with a proposed Tariff of Rates and Charges no later than **November 26, 2024**. Algoma Power shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order.

3. The Accounting Orders set out in Schedule B, C and D of this Partial Decision and Order are approved.

4. Intervenors and OEB staff may file any comments on the draft rate order with the OEB no later than **November 29, 2024**.

5. Algoma Power may file with the OEB and forward to intervenors, responses to any comments on its draft rate order no later than **December 4, 2023**.

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-2024-0007** 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, Birgit Armstrong at birgit.armstrong@oeb.ca and OEB Counsel, Ian Richler at ian.richler@oeb.ca.

DATED at Toronto November 19, 2024

ONTARIO ENERGY BOARD

Nancy Marconi
Digitally signed by Nancy Marconi
Date: 2024.11.19 16:07:32 -05'00'

Nancy Marconi
Registrar

SCHEDULE A

PARTIAL DECISION AND ORDER

SETTLEMENT PROPOSAL ON ELEGIBLE ISSUES

ALGOMA POWER INC.

EB-2024-0007

NOVEMBER 19, 2024

EB-2024-0007

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
Algoma Power Inc.
For an order approving just and reasonable rates and
Other charges for electricity distribution beginning
January 1, 2025.

Algoma Power Inc.

Settlement Proposal- Settlement on All Eligible Issues

Filed: October 25, 2024

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LIST OF ATTACHMENTS

API has filed revised models as evidence to support this Settlement Proposal. The models have been filed through the OEB's e-filing service and include:

1. OEB Chapter 2 Appendices
2. Revenue Requirement Workform
3. Income Tax PILs Model
4. Load Forecast Model
5. Cost Allocation Model
6. DVA Continuity Schedule
7. RTSR Model
8. Tariff Schedule and Bill Impact Model
9. Load Profile Scaling Model

SETTLEMENT PROPOSAL

Algoma Power Inc. (the Applicant or API) filed a Cost-of-Service application with the Ontario Energy Board (the OEB) on June 1, 2024, 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 API charges for electricity distribution, to be effective January 1, 2025 (OEB file number EB-2024-0007) (the Application).

The OEB issued a Letter of Direction and Notice of Application on June 27, 2024. In Procedural Order No. 1, dated July 22, 2024, the OEB approved the Vulnerable Energy Consumers Coalition (VECC) and the School Energy Coalition (SEC) as intervenors.

The Procedural Order indicated the prescribed dates for the filing of a proposed Issues List, the submission of interrogatories, API's responses to interrogatories, a Settlement Conference, and various other elements in the proceeding.

On July 29, 2024, OEB Staff, on behalf of the parties, submitted a proposed issues list (the Issues List) to the OEB for approval. The OEB approved the Issues List on August 2, 2024. As part of the Issues List approval the OEB excluded issue 6.2 from the settlement process; accordingly, there is no settlement of issue 6.2, and any reference to settled issues or a complete settlement of issues herein does not purport to include a settlement of issue 6.2. By way of reference, issue 6.2 is as follows:

> *6.2 Is the proposal for the disposition of balances in Accounts 1588 and 1589, including the request for an order as per Section 36.1.1 of the Electricity Act, 1998 requiring the IESO to settle past Class A submissions, appropriate?*

On August 8, 2024, the OEB approved the Independent Electricity System Operator (the "IESO") as an intervenor in the proceeding.

API filed its interrogatory responses with the OEB on September 4, 2024.

The Settlement Conference was convened on September 18, 19, 20, 23, 24 and 25, 2024, in accordance with the OEB's Rules of Practice and Procedure (the Rules) and the OEB's Practice Direction on Settlement Conferences. VECC, SEC, the IESO and OEB Staff participated in the Settlement Conference.

Sarah Daitch acted as the facilitator for the Settlement Conference.

API, VECC, SEC and the IESO (collectively referred to as the Parties), reached a full, comprehensive settlement regarding API's 2025 Cost of Service Application (outside of issue 6.2). The details and specific components of the settlement are detailed in this Settlement Proposal.

Notwithstanding any other wording in this Settlement Proposal, the IESO neither supports nor opposes any elements of this Settlement Proposal, and takes no position on the issues addressed in this Settlement Proposal

This document is called a Settlement Proposal because it is a proposal by the Parties presented 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. In entering into this Settlement Proposal, 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 was confidential in accordance with the OEB's Practice Direction on Settlement Conferences. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's Practice Direction on Confidential Filings, and the rules of that latter document do not apply. Instead, in this Settlement Conference, and in this Settlement Proposal, the specific rules with respect to confidentiality and privilege are as set out in the Practice Direction on Settlement Conferences, as amended on February 17, 2021. The Parties have interpreted the revised Practice Direction on Settlement Conferences to mean that the documents and other information provided during the Settlement Conference itself, the discussion of each issue, the offers and counteroffers, 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 are deemed to include, in this context, persons who were not in attendance at the Settlement Conference but were a) any persons or entities that the Parties engaged to assist them with the Settlement Conference, and b) any persons or entities from whom the attendees' sought instructions with respect to the negotiations, in each case provided those persons are subject to the same obligations of confidentiality and privilege as those persons actually in attendance.

OEB staff also participated in the Settlement Conference. The role adopted by OEB staff is set out in page 5 of the Practice Direction on Settlement Conferences. Although OEB staff is not a party to this Settlement Proposal, as noted in the Practice Direction on Settlement Conferences, 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 Settlement Proposal provides a brief description of each of the 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, in addition to the Application, the responses to interrogatories, all other components of the record up to and including the date hereof, and the additional information included by the Parties in this Settlement Proposal and the attachments and appendices to this document.

Included with the Settlement Proposal are attachments that provide further support for the proposed settlement, including responses to Pre-Settlement Clarification questions (Clarification Responses). The Parties acknowledge that the attachments were prepared by API. The Parties have reviewed the attachments and are relying on the accuracy of the attachments and the underlying evidence in entering into this Settlement Proposal.
For ease of reference, this Settlement Proposal follows the format of the final approved Issues List.

According to section 6 of the Practice Direction on Settlement Conferences, 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. Any such 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 accepts may continue as a valid settlement without inclusion of any part(s) that the OEB does not accept).

If 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 the Parties must agree with any revised Settlement Proposal as it relates to that issue, or take no position, 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 the Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not API is a party to such proceeding, provided that no Party shall take a position that would result in the Settlement Proposal not applying in accordance with the terms contained herein.

Where, in this Settlement Proposal, the Parties accept the evidence of API, or agree to any issue, 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.

SUMMARY

The Parties were able to reach agreement on all aspects of the Application with respect to capital costs, operations, maintenance & administration (OM&A) costs, revenue requirement-related issues, including the accuracy of the revenue requirement determination and the application of OEB policies and practices (excluding the settlement of issue 6.2 per the OEB's direction).

In reaching this Settlement Proposal, the Parties have been guided by the Filing Requirements for 2024 rates and the approved Issues List.

The Parties have described below, in detail, areas where they have settled an issue by agreeing to adjustments to the Application as updated.

This Settlement Proposal will, if accepted, result in a total bill decrease of $(3.28) per month for the typical residential customer consuming 750 kWh per month.

The financial impact of the Settlement Proposal is to reduce the total revenue requirement requested of $35,768,551 by $(1,249,550) to $34,519,000.

A Revenue Requirement Work Form (RRWF) incorporating all terms that have been agreed to is filed with the Settlement Proposal. Through the settlement process, API has agreed to certain adjustments to its original Application. The changes are described in the following sections.

API has provided the following tables summarizing the Application and highlighting the changes to its Rate Base and Capital, Operating Expenses, and Revenue Requirement as between API's Application as filed, the interrogatory process and this Settlement Proposal.

Table 1 – Summary of 2025 Revenue Requirement

Particular	Original Application June 1, 2024	Response to IRs September 4, 2024	Variance over Original Application	Settlement Proposal October 25, 2024	Variance over IRs
Long Term Debt	5.59%	5.12%	0%	5.12%	0%
Short Term Debt	6.23%	6.23%	0%	6.23%	0%
Return on Equity	9.21%	9.21%	0%	9.21%	0%
Regulated Rate of Return	**7.06%**	**6.80%**	0%	**6.80%**	0%
Controllable Expenses	$ 16,579,014	$ 16,579,014	$ -	$ 15,608,227	-$ 970,787
Power Supply Expense	$ 32,534,015	$ 33,446,726	$ 912,711	$ 32,698,009	-$ 748,717
Total Eligible Distribution Expenses	$ 49,113,029	$ 50,025,740	$ 912,711	$ 48,306,236	-$ 1,719,504
Working Capital Allowance Rate	7.50%	7.50%	0%	7.50%	0%
Total Working Capital Allowance ("W	**$ 3,683,477**	**$ 3,751,931**	$ 68,453	**$ 3,622,968**	-$ 128,963
Fixed Asset Opening Bal Test Year	$ 172,167,954	$ 172,167,954	$ -	$ 172,759,898	$ 591,944
Fixed Asset Closing Bal Test Year	$ 176,058,022	$ 176,058,022	$ -	$ 178,834,637	$ 2,776,615
Average Fixed Asset	$ 174,112,988	$ 174,112,988	$ -	$ 175,797,268	$ 1,684,280
Working Capital Allowance	$ 3,683,477	$ 3,751,931	$ 68,453	$ 3,622,968	-$ 128,963
Rate Base	**$ 177,796,465**	**$ 177,864,919**	$ 68,453	**$ 179,420,236**	$ 1,555,317
Regulated Rate of Return	7.06%	6.80%	0%	6.80%	0%
Regulated Return on Capital	**$ 12,555,753**	**$ 12,094,636**	-$ 461,117	**$ 12,200,396**	$ 105,760
Deemed Interest Expense	$ 6,005,731	$ 5,542,092	-$ 463,639	$ 5,590,554	$ 48,462
Deemed Return on Equity	$ 6,550,022	$ 6,552,544	$ 2,522	$ 6,609,841	$ 57,297
OM&A	$ 16,319,014	$ 16,319,014	$ -	$ 15,348,227	-$ 970,787
Depreciation Expense	$ 5,675,782	$ 5,675,782	$ -	$ 5,748,111	$ 72,329
Property Taxes	$ 260,000	$ 260,000	$ -	$ 260,000	$ -
PILs	$ 958,002	$ 958,912	$ 910	$ 962,267	$ 3,355
Service Revenue Requirement	**$ 35,768,551**	**$ 35,308,344**	-$ 460,207	**$ 34,519,000**	-$ 789,344
Revenue Offset	$ 656,000	$ 646,454	-$ 9,546	$ 786,454	$ 140,000
Base Revenue Requirement	**$ 35,112,551**	**$ 34,661,890**	-$ 450,661	**$ 33,732,546**	-$ 929,344

Based on the foregoing, and the evidence and rationale provided below, the Parties accept this Settlement Proposal as appropriate and recommend its acceptance by the OEB. Table 2 below illustrates the updated bill impacts that would result from the acceptance of this Settlement Proposal.

Table 2 - Bill Impact Summary

	Sub-Total A		Sub-Total B		Sub-Total C		Total Bill	
Classification	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Residential R1(i)	$ (1.35)	-3.25%	$ (3.91)	-7.75%	$ (3.30)	-5.01%	$ (3.27)	-2.25%
Residential R1(ii)	$ 3.82	3.47%	$ (3.02)	-2.26%	$ (1.38)	-0.79%	$ (1.33)	-0.34%
Residential R2	$ (442.72)	-16.74%	$ (1,397.41)	-40.15%	$ (1,268.24)	-17.92%	$ (1,314.91)	-3.55%
Seasonal	$ 8.58	8.96%	$ 8.26	8.41%	$ 8.43	8.23%	$ 8.42	6.80%
Seasonal-10th percentile	$ 7.43	8.39%	$ 7.41	8.31%	$ 7.42	8.29%	$ 7.42	8.12%
Street Lighting	$ (67.21)	-5.27%	$ (84.72)	-6.59%	$ (82.85)	-6.19%	$ (81.37)	-4.79%

The chart below outlines the rates that comprise the Sub-Totals 'A', 'B', 'C', and Total Bill in Table 2 above:

Subtotal A	Sub-Total B - Distribution (includes Sub-Total A)	Sub-Total C - Delivery (including Sub-Total B)	Total Bill - Sub-Total C and Items below
Monthly Service Charge	Line Losses on Cost of Power	RTSR - Network	Wholesale Market Service Charge (WMSC)
Distribution Volumetric Rate	Total Deferral/Variance Account Rate Riders	RTSR - Connection and/or Line and Transformation Connection	Rural and Remote Rate Protection (RRRP)
Fixed Rate Riders	CBR Class B Rate Riders		Standard Supply Service Charge
Volumetric Rate Riders	GA Rate Riders		Ontario Electricity Support Program (OESP) if applicable
Distribution Rate Protection (DRP)	Low Voltage Service Charge		Commodity
	Smart Meter Entity Charge (if applicable)		HST
	Additional Fixed Rate Riders		OER (if applicable)
	Additional Volumetric Rate Riders		

SETTEMENT PROPOSAL BY ISSUE NUMBER

1. Capital Spending and Rate Base

1.1 Are the proposed capital expenditures and in-service additions appropriate?

Full Settlement

The Parties agree to API's proposed 2024 capital expenditures and 2024 net capital additions of $14,625,600 inclusive of 2024 ACM additions[1], or $14,270,698 before ACM additions[2]. The Parties agree to API's proposed 2025 capital expenditures and 2025 net capital additions for the purpose of setting rates of $12,437,489.

These 2024 and 2025 amounts reflect a net increase of $600,000 in 2024, and $2,227,000 in 2025 from the original Application, based on the following adjustments:

a) Relative to the forecast 2025 net in service additions of $10,210,489 as originally requested in the Application, API agrees to a reduction of $1.5M;

b) In connection with the settlement of issue 1.2, and separately from the adjustment described in a) above, API agrees to move $400,000 of forecast 2024 in service additions to 2024 CWIP to reflect timing differences and instead recognize the $400,000 capital spending as in service additions in 2025;

c) In connection with the proposed settlement of issue 6.1 as it relates to the approval of the new Land Use Revenue Requirement Variance Account (the "LURR" VA) and API's agreement to remove $643,787 in revenue requirement from its forecast 2025 Land Use Rights OM&A budget as described under issue 2.1, API agrees to reflect forecast in service additions of $3.327M in 2025 and (as noted under issue 1.2) $1.0M in 2024 in relation to Land Use agreements, in order to establish a baseline Land Use rights related revenue requirement for the new variance account. Further details about the proposed LURR VA are provided under issue 6.1.

As a result of the adjustments described above, the Parties agree that the settled net in service additions in 2025 will be $12,437,489 for the purposes of setting 2025 rates.

In furtherance on the settlement of the 2024 and 2025 capital expenditures and 2024 and 2025 net capital additions, API has made notional changes to its forecast spending to set the test year rates. The notional changes have been reflected to the categories of capital spending, as summarized in Table 3 below, and further detail can be found in the attached Appendix 2-AA.

[1] Consistent with the treatment in Appendix 2-AA.

[2] Consistent with the treatment in Appendix 2-BA

As part of this settlement the Parties recognize that API retains the discretion to adjust its capital spending as it sees fit in order to effectively manage its distribution system, notwithstanding the notional changes made in the context of the Settlement Proposal.

In addition to the above noted changes to the net service additions for 2025, API has agreed to the following obligations:

a) At its next rebasing application, API shall file an updated Asset Condition Assessment and report back on the steps it has taken to address the data gaps identified by METSCO in its previous Asset Condition Assessments.

b) At its next rebasing application, API shall provide project cost variance reports for any capital project with an estimate of $1.5M or over during the rate term that has a cost variance of 10% or greater.

c) In its next Distribution System Plan, API shall provide a description and explanation of its Project Management process and any modification or improvements made over the rate term.

d) At its next rebasing application, API shall provide a description of its project estimating process and any modifications or improvements made over the rate term.

Table 3 – 2024 and 2025 Capital Expenditures

2024 Bridge Year* In-Service Additions ($000s)							
	Original Application 01-Jun-24	**Response to IRs September 4, 2024**	**Variance over Original Application**	**Settlement Proposal October 25, 2024**	***Increases Over IRs***	***Decreases Over IRs***	**Net Variance over IRs**
System Access	$3,295	$3,295	$0	$3,295	*$0*	*$0*	$0
System Renewal	$12,397	$12,397	$0	$11,997	*$0*	*-$400*	-$400
System Service	$1,684	$1,684	$0	$1,684	*$0*	*$0*	$0
General Plant	$1,901	$1,901	$0	$2,901	*$1,000*	*$0*	$1,000
Capital Contribution	-$5,252	-$5,252	$0	-$5,252	*$0*	*$0*	$0
Total Expenditures	**$14,026**	**$14,026**	$0	**$14,626**	*$1,000*	*-$400*	$600

** Additions correspond with Appendix 2-AA/2-AB and include ACM in-service additions. For fixed asset continuity (App 2-BA), a different treatment applies to ACM additions.*

2025 Test Year In-Service Additions ($000s)							
	Original Application 01-Jun-24	**Response to IRs September 4, 2024**	**Variance over Original Applicatio**	**Settlement Proposal October 25, 2024**	***Increases Over IRs***	***Decreases Over IRs***	**Net Variance over IRs**
System Access	$1,465	$1,465	$0	$1,355	*$0*	*-$110*	-$110
System Renewal	$5,752	$5,752	$0	$5,362	*$120*	*-$510*	-$390
System Service	$1,054	$1,054	$0	$1,054	*$0*	*$0*	$0
General Plant	$2,039	$2,039	$0	$4,766	*$3,327*	*-$600*	$2,727
Capital Contribution	-$100	-$100	$0	-$100	*$0*	*$0*	$0
Total Expenditures	**$10,210**	**$10,210**	$0	**$12,437**	*$3,447*	*-$1,220*	$2,227

The Parties accept the evidence of API that the level of planned capital expenditures over the course of its Distribution System Plan and the rationale for planning and pacing choices are appropriate to maintain system reliability, service quality objectives and the reliable and safe operation of the distribution system.

The Parties note that this Settlement Proposal and the underpinning capital budgets were developed prior to the publication of the OEB's *Report Back to the Minister on System Expansion for Housing Developments.* Accordingly, the budgets for capital contributions were developed based on a standard maximum 25-year expansion horizon.

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 2 – Rate Base
- EXHIBIT 2 – Distribution System Plan

IR Responses

2-Staff-26a-c; 2-Staff-13; 2-Staff-6; 2-Staff-5; 2-Staff-15; 2-Staff-16; 2-Staff-17; 2-Staff-18; 2-Staff-20; 2-Staff-22; 2-Staff-23; 2-Staff-24; 2-Staff-25; 2-Staff-26; 2-Staff-27; 2-Staff-28; 1-SEC-6; 2-SEC-8; 2-SEC-9; 2-Sec-12; 2-Sec-14; 2-Sec-15; 2-Sec-17; 2-Sec-18; 2-Sec-19; 1-VECC-1; 1-VECC-2; 2-VECC-7; 2-VECC-10; 2-VECC-11; 2-VECC-12; 2-VECC-13; 2-VECC-14; 2-VECC-17; 9-Staff-67.

Clarification Questions

PSC-SEC-42; PSC-VECC-49; PSC-Staff-1; PSC-VECC-50; PSC-Staff-2; PSC-Staff-3; PSC-Staff-4; PSC-Staff-5; PSC-Staff-6; PSC-Staff-14

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

1.2 Are the proposed rate base and depreciation amounts appropriate?

Full Settlement

The Parties agree that API's proposed 2025 rate base and depreciation amounts, including the methodology used to calculate depreciation and the methodology to calculate the Working Capital Allowance, are appropriate subject to the following adjustments:

a) API agrees to move $400,000 of its proposed in-service additions for 2024 into 2024 CWIP and place that spending into service in 2025 to reflect timing differences.

b) In connection with the proposed settlement of issue 6.1 as it relates to the approval of the new Land Use Revenue Requirement Variance Account (LURRVA) and API's agreement to remove $643,787 in revenue requirement from its forecast 2025 Land Use Rights OM&A budget as described under issue 2.1, API agrees to reflect $1.0M in forecast in-service additions in 2024 in relation to Land Use agreements, with a corresponding impact on API's forecast opening 2025 rate base. API also agrees to reflect $3.327M in forecasted in-service additions in 2025 as noted under issue 1.1. Further details about the proposed LURR VA are provided at issue 6.1.

The Parties note in particular their agreement that the advancement credit (also referred to as replacement credit) proposed in relation to the #4 Circuit (*representing the discounted value of work which API would have completed in the future to reduce the project costs allocated to the customer)* in Exhibit 2 section 2.1.1 is appropriate.

Further, and separate from the advancement credit, the Parties agree under section 6.1(d) to establish a variance account in the event that the C-E portion of the #4 Circuit be sold by API[3].

Table 4 – 2025 Working Capital

Particulars	**Original Application** **01-Jun-24**	**Response to IRs September 4, 2024**	**Variance over Original Application**	**Settlement Proposal October 25, 2024**	**Variance over IRs**
Controllable Expenses	$ 16,579,014	$ 16,579,014	$0	$ 15,608,227	-$970,787
Cost of Power	$ 32,534,015	$ 33,446,726	$912,711	$ 32,698,009	-$748,717
Working Capital Base	$ 49,113,029	$ 50,025,740	$912,711	$ 48,306,236	-$1,719,504
Working Capital Rate %	7.5%	7.5%	0.0%	7.5%	0.0%
Working Capital Allowance	$ 3,683,477	$ 3,751,931	$68,453	$ 3,622,968	-$128,963

[3] With the Interrogatory responses submitted September 4, 2024, API identified the potential for a future sale of a portion (section C-E) of its #4 Circuit line. Please also see the responses to Clarification Questions SEC-38 and OEB Question 1.

Table 5 – 2025 Rate Base

Particulars	Original Application 01-Jun-24	Response to IRs September 4, 2024	Variance over Original Application	Settlement Proposal October 25, 2024	Variance over IRs
Gross Fixed Assess (Average)	$ 272,738,705	$ 272,738,705	$0	$ 274,452,205	$1,713,500
Accumulated Depreciation (Average)	-$ 98,625,717	-$ 98,625,717	$0	-$ 98,654,937	-$29,220
Net Fixed Assets (Average)	$ 174,112,988	$ 174,112,988	$0	$ 175,797,268	$1,684,280
Allowance for Working Capital	$ 3,683,477	$ 3,751,931	$68,453	$ 3,622,968	-$128,963
Total Rate Base	$ 177,796,465	$ 177,864,919	$68,453	$ 179,420,236	$1,555,317

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 2 – Rate Base
- EXHIBIT 2 – Distribution System Plan

IR Responses

(Generally the same as Issue 1.1); 2-Staff-16-E,F

Clarification Questions

(Generally the same as Issue 1.1)

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

1.3 Is the in-service addition of the Sault St. Marie Facility ACM project appropriate?

Full Settlement

The Parties agree that while concerns were raised and explored with respect to the escalation of costs in relation to the Sault St. Marie Facility relative to the maximum project cost of $12.69M approved in settlement (EB-2019-0009) during the course of the proceeding, the Parties have agreed, as part of the overall Settlement Proposal and, in particular, the settlement proposals under issues 1.1 and 1.2 including API's agreement to several reporting requirements under issue 1.1 in connection with its capital planning and spending in the years until its next COS, to accept the proposed in-service additions related to the Sault St. Marie Facility as proposed by API. Specifically, $16,654,663 related to in-service additions in 2024 and years prior, less accumulated depreciation of $735,302 to be added to the Test Year opening Rate Base.

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 2 – Rate Base (Note Explanation on Page 92).
- EXHIBIT 2 – Distribution System Plan

IR Responses

9-Staff-67; 9-Staff-68;2-Staff-30; 2-Staff-31;6-Staff-53; 2-SEC-10; 2-VECC-9;

Clarification Questions

PSC-SEC-42a

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

1.4 Is the in-service addition of the Echo River TS ACM project appropriate?

Full Settlement

The Parties accept the in-service additions as proposed by API relative to the Echo River TS approved in settlement (EB-2019-0009). Specifically, $11,006,211 less accumulated depreciation of $343,349 related to in-service additions in 2024 and years prior will be added to the 2025 opening rate base.

In agreeing to the proposed additions, the Parties wish to express their concern at Hydro One Sault Ste. Marie (HOSSM)'s apparent reluctance to respond to information requests related to cost overruns compared to the original $7.766 M estimate, and schedule delays, both from API during the course of project construction[4], and from the Parties throughout this proceeding[5].

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 2 – Rate Base
- EXHIBIT 2 – Distribution System Plan

IR Responses

2-Staff-29; 6-Staff-53; 2-SEC-11; 2-VECC-8; 9-Staff-67.

Clarification Questions

PSC-SEC-39; PSC-SEC-42a

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

[4] Please refer to Interrogatory Response 2-Staff-29 and Attachment 2-Staff-29.
[5] Clarification Question SEC-39

2. OM&A

2.1 Are the proposed OM&A expenditures appropriate?

Full Settlement

The Parties have agreed that API's proposed 2025 OM&A budget is appropriate, subject to the following adjustments:

a) In connection with the proposed settlement of issue 6.1 as it relates to the approval of the new the LURR VA, API agrees to remove $643,787 in revenue requirement from its forecast 2025 Land Use Rights OM&A budget.

   In its Application, API had proposed to include $645,787 in OM&A as the placeholder revenue requirement value for incremental future land rights, whether expensed or capitalized. As a result of the adjustments to Capital outlined in issue 1.1, instead $643,787 of the adjustment has been removed and reflected as a capital placeholder, and $2,000 in incremental funding has been kept as the OM&A placeholder (which in addition to the $122,122 budget for existing agreements, results in the Land Use RR VA OM&A baseline of $124,122) .

b) API agrees to, incremental to the reduction described in a) above, reduce its overall 2025 forecast OM&A budget by $327,000.

With these two adjustments the Parties agree that the new 2025 forecast OM&A budget for the purposes of setting rates is $15,348,227. In agreeing to the proposed budget, the Parties note that it represents an annual increase in OM&A expense from API's 2020 Board Approved OM&A Budget to 2025 of 2.3%, which the Parties submit compares favourably to an expected 3.3%% annualized increase when considering the combined impact of the OEB's annual PCI, the forecast 4.5%% increase in API's customer base between 2020 and 2025, and the unique cost pressures faced by API given the nature of its service territory, particularly the pressures faced by API in connection with its vegetation management requirements.

In settling the 2025 Test Year OM&A budget the Parties acknowledge that API retains the discretion to manage its OM&A budget as it sees fit in order to responsibly manage its distribution system, notwithstanding the notional adjustments it has made to the forecast budget in order to reflect the settlement related adjustments.

Table 6 - 2025 Test Year OM&A Expenses

	Original Application 01-Jun-24	Response to IRs September 4, 2024	Variance over Original Application	Settlement Proposal October 25, 2024	Variance over IRs
Operations	$2,563,055	$2,563,055	$0	$1,919,268	-$643,787
Maintenance	$6,711,543	$6,711,543	$0	$6,711,543	$0
Billing and Collecting	$1,085,080	$1,085,080	$0	$1,085,080	$0
Community Relations	$75,220	$75,220	$0	$75,220	$0
Administration & General +LEAP	$5,884,116	$5,884,116	$0	$5,557,116	-$327,000
Total	**$16,319,014**	**$16,319,014**	**$0**	**$15,348,227**	-$970,787

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 4 – OM&A

IR Responses

1-Staff-2; 1-Staff-3; 2-Staff-21; 4-Staff-37; 4-SEC-22; 4-Staff-42; 4-Staff-43; 4-Staff-44; 4-Staff-45; 4-Staff-46; 4-Staff-47; 4-Staff-48; 4-Staff-49; 2-SEC-16; 4-SEC-22; 4-SEC-24; 4-SEC-25; 4-SEC-27; 4-SEC-28; 4-SEC-29; 2-VEC-4; 4-VECC-24; 4-VECC-25; 4-VECC-27; 4-VECC-28; 4-VECC-28; 4-VECC-30; 4-VECC-31; 4-VECC-32

Clarification Questions

PSC-SEC-43; PSC-SEC-44; PSC-VECC-51; PSC-Staff-7.

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

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

Full Settlement

The Parties accept, for the purpose of the 2025 Test Year, API's proposed shared services cost allocation methodology.

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 4 – Operating Expenses

IR Responses

4-Staff-39; 4-Staff-40; 4-Staff-41; 4-SEC-30

Clarification Questions

N/A

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

3. Cost of Capital, PILs, and Revenue Requirement

3.1 Is the proposed cost of capital (interest on debt, return on equity) and capital structure appropriate?

Full Settlement

The Parties agree to API's proposed cost of capital parameters as reflected below, which are based on, where appropriate, the OEB's cost of capital parameters for 2024 Cost of Service applications as a placeholder.

The Parties agree that API will update the calculations when the OEB's deemed ROE and Short Term Debt rates for 2025 Cost of Service applications are issued; the Parties note that the weighted average cost of Long-Term Debt does not require updating as it is based entirely on existing 3rd party fixed rate instruments.

Table 7 - 2025 Cost of Capital Calculation

Particulars	Original Application 01-Jun-24	Response to IRs September 4, 2024	Variance over Original Application	Settlement Proposal October 25, 2024	Variance over IRs
Debt					
Long-term Debt (weighted)	5.59%	5.12%	-0.47%	5.12%	0.00%
Short-term Debt	6.23%	6.23%	0.00%	6.23%	0.00%
Total Debt (weighted)	5.63%	5.19%	-0.44%	5.19%	0.00%
Equity	9.21%	9.21%	0.00%	9.21%	0.00%
Total Equity	9.21%	9.21%	0.00%	9.21%	0.00%
Total	**7.06%**	**6.80%**	-0.26%	**6.80%**	0.00%

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 5 – Cost of Capital and Capital Structure

IR Responses

1-Staff-1; 5-Staff-52

Clarification Questions

PSC-SEC-40

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

3.2 Is the proposed PILs (or Tax) amount appropriate?

Full Settlement

The Parties accept API's updated calculations of forecast PILs in this Settlement Proposal, including API's proposal to smooth the impacts of the phase out of accelerate CCA rules during API's next IRM period.

The smoothing amount of $212,000 included in 2025 Test Year PILS model, Schedule 1 Taxable Income Test, is calculated using a 5-year smoothing method, as outlined in Exhibit 6. Table 13 of Exhibit 6 shows how the $212,000 was derived and has been re-produced below.

Table 8 - Smoothing Adjustment to 2025 Test Year for Enhanced CCA

	2028	2029	Cumulative Total
	Forecast	Forecast	Forecast
Planned Capital	$9,965,000	$10,631,000	$20,596,000
CCA Using 2025 Test Year Rates	$1,230,040	$2,123,716	$3,353,756
CCA Using Rates per Bill C-97	$615,020	$1,676,878	$2,291,898
CCA Difference	$615,020	$446,838	$1,061,858
Take 1/5 of Difference			**$212,000**

A summary of the updated PILs calculation is presented in Table 8 below.

Table 9 - 2025 Income Taxes

	Original Application 01-Jun-24	Response to IRs September 4, 2024	Variance over Original Application	Settlement Proposal October 25, 2024	Variance over IRs
Income Taxes (Grossed up)	$958,002	$958,912	$910	$962,267	$3,355

An updated Income Tax/PILs Model has been submitted in Live Excel format as part of this Settlement Proposal.

The Parties acknowledge that further adjustments to PILS calculation may be necessary when updates are made for the Cost of Capital.

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 6 – Revenue Requirement and Revenue Deficiency or Sufficiency

IR Responses

1-Staff-1; 6-Staff-55; 6-Staff-56; 6-Staff-57; 6-Staff-58; 6-SEC-32

Clarification Questions
PSC-Staff-10; PSC-Staff-11

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

3.3 Is the proposed Other Revenue forecast appropriate?

Full Settlement

The Parties agree that API's other revenue forecast is appropriate, subject to a total increase of $140,000. This increase has been reflected across the categories of other revenue, as summarized in Table 9 below.

The Parties note that the $140,000 adjustment is not tied to a particular issue with the Other Revenue forecast per se. Rather, the adjustment is being made in the context of the Settlement Proposal as a whole. While the Parties recognize that the Settlement Proposal addresses individual issues, it is also intended to address the overall revenue requirement used to set rates. In order to achieve consensus on the overall package of settled issues within the Settlement Proposal, the Parties agreed to the adjustment in order to achieve an overall revenue requirement for the purposes of settlement. Because this adjustment is not, in the first instance, being attributed to any particular issue by the Parties to the Settlement Proposal, but rather is employed as a mechanism to reduce the overall revenue requirement used for rate setting purposes, the Parties agreed that is was appropriate to reflect such an adjustment as a change to the Other Revenue forecast, subject to avoiding adjustments to line items within the Over Revenue Forecast that act as base line spending amounts for the purpose of certain Variance Accounts as outlined under issue 6.1.

A summary of the updated Revenue Offsets is presented in Table 9 below.

Table 10 - 2025 Revenue Offsets

	Original Application 01-Jun-24	Response to IRs September 4, 2024	Variance over Original Application	Settlement Proposal October 25, 2024	Variance over IRs
Specific Service Charges	$90,000	$90,000	$0	$90,000	-$0
Late Payment Charges	$40,000	$40,000	$0	$40,000	$0
Other Distribution Revenues	$499,000	$489,454	-$9,546	$629,454	$140,000
Other Income and Deductions	$27,000	$27,000	$0	$27,000	$0
Total	**$656,000**	**$646,454**	-$9,546	**$786,454**	$140,000

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 6 – Revenue Requirement and Revenue Deficiency or Sufficiency

IR Responses

6-Staff-53; 6-Staff-54

Clarification Questions

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

3.4 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?

Full Settlement

The Parties accept the evidence of API that all impacts of any changes to accounting standards, policies, estimates, and adjustments have been properly identified in the Application and the interrogatories and have been recorded and treated appropriately in the ratemaking process.

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 4 – Operating Expenses
- EXHIBIT 6 – Revenue Requirement and Revenue Deficiency or Sufficiency

IR Responses

5-Staff-50; 5-Staff-51

Clarification Questions

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

3.5 Is the proposed calculation of the Revenue Requirement appropriate?

Full Settlement

The Parties agree that the methodology used by API to calculate the Revenue Requirement is appropriate.

A summary of the adjusted Base Revenue Requirement of $33,732,547 reflecting adjustments and settled issues is presented in Table 11 - 2025 Revenue Requirement Summary below.

Table 8 - 2025 Revenue Requirement Summary

	Original Application 01-Jun-24	Response to IRs September 4, 2024	Variance over Original Application	Settlement Proposal October 25, 2024	Variance over IRs
OM&A Expenses	$16,319,014	$16,319,014	$0	$15,348,227	-$970,787
Amortization/Depreciation	$5,675,782	$5,675,782	$0	$5,748,111	$72,329
Property Taxes	$260,000	$260,000	$0	$260,000	$0
Income Taxes (Grossed up)	$958,002	$958,912	$910	$962,267	$3,355
Return					
Deemed Interest Expense	$6,005,731	$5,542,092	-$463,639	$5,590,554	$48,462
Return on Deemed Equity	$6,550,022	$6,552,544	$2,522	$6,609,841	$57,297
Service Revenue Requirement (before Other Revenue Offsets)	**$35,768,551**	**$35,308,344**	**-$460,207**	**$34,519,000**	-$789,344
Revenue Offsets	$656,000	$646,454	-$9,546	$786,454	$140,000
Base Revenue Requirement	**$35,112,551**	**$34,661,890**	-$450,661	**$33,732,546**	-$929,344
Gross Revenue Deficiency/Sufficiency	$3,193,707	$2,743,045	-$450,662	$2,443,031	-$300,014

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 4 – Operating Expenses
- EXHIBIT 6 – Revenue Requirement and Revenue Deficiency or Sufficiency

IR Responses

1-Staff-1; 1-Staff-4; 6-SEC-33.

Clarification Questions

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

4. Load Forecast

4.1 Is the proposed load forecast methodologies and the resulting load forecasts appropriate?

Full Settlement

The Parties agree that the updated load forecast filed with this Settlement Proposal is appropriate for the purpose of setting rates. The Parties note that the new load forecast that is being used to underpin the rates in the Settlement Proposal, incorporates customer count data up to June 2024 and a revised approach to account for new load associated with the #4 Circuit Line

Table 9 – 2025 Test Year Billing Determinants

Tariff Classification	Particulars	Original Application 01-Jun-24	Response to IRs September 4, 2024	Variance over Original Application	Settlement Proposal October 25, 2024	Variance over IRs
	kWh					
Residential R1 (i)	Residential	102,025,758	102,025,758	0	99,118,975	-2,906,784
Residential R1 (ii)	General Service < 50 kW	29,627,607	29,627,607	0	29,217,510	-410,097
Residential R1 Subtotal	**Residential R1 Subtotal**	**131,653,365**	**131,653,365**	**0**	**128,336,485**	**-3,316,880**
Residential R2	General Service > 50 kW	179,389,418	179,389,418	0	172,482,673	-6,906,745
Seasonal	Seasonal	5,958,052	5,958,052	0	5,961,327	3,275
Street Lighting	Street Lighting (Connections)	548,977	548,977	0	536,180	-12,797
	Total	**317,549,812**	**317,549,812**	**0**	**307,316,665**	**-10,233,147**
	kW					
Residential R2	General Service > 50 kW	372,457	372,457	0	345,623	-26,834
Street Lighting	Street Lighting	1,533	1,533	0	1,497	-36
	Total	**373,990**	**373,990**	**0**	**347,120**	**-26,870**

Table 13 below details the number of customers and connections for the test year.

Table 13 – Number of Customers & Connections

Tariff Classification	Particulars	Original Application 01-Jun-24	Response to IRs September 4, 2024	Variance over Original Application	Settlement Proposal October 25, 2024	Variance over IRs
Residential R1 (i)	Residential	8,621	8,621	0	8,635	14
Residential R1 (ii)	General Service < 50 kW	1,053	1,053	0	1,071	18
Residential R1 Subtotal	Residential R1 Subtotal	**9,674**	**9,674**	0	**9,705**	31
Residential R2	General Service > 50 kW	45	45	0	46	1
Seasonal	Seasonal	2,717	2,717	0	2,719	2
Street Lighting	Street Lighting (Connections)	1,156	1,156	0	1,129	-27
	Total	**13,592**	**13,592**	0	**13,599**	7

Evidence References

- EXHIBIT 3 – Load and Customer Forecast

IR Responses

3-Staff-33; 3-Staff-34; 3-Staff-35; 3-Staff-36; 8-Staff-56; 3-SEC-20; 3-SEC-21; 3-VECC-18; 3-VECC-19; 3-VECC-20; 3-VECC-22; 3-VECC-23

Clarification Questions

PSC-VECC-46; PSC-VECC-47; PSC-VECC-48

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

5. Cost Allocation, Rate Design, and Other Charges

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

Full Settlement

The Parties accept the results of API's cost allocation methodology and its proposed revenue-to-cost ratios, as updated through the interrogatory process and to reflect changes resulting from this Settlement Proposal. As outlined in issue 5.6, this Settlement Proposal no longer considers any revenue-to-cost ratio changes beyond the test year due to rate mitigation (or any other reason).

Table 10 – Summary of 2025 Revenue-to-Cost Ratios

	Original Application June 1, 2024			Response to IRs September 4, 2024			Settlement Proposal October 25, 2024		
Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Var	Calculated R/C Ratio	Proposed R/C Ratio	Var	Calculated R/C Ratio	Proposed R/C Ratio	Var
Residential R1	102.31%	102.31%	0.00%	107.87%	106.84%	-1.03%	107.92%	106.30%	-1.62%
Residential R2	112.25%	108.56%	-3.69%	93.15%	93.15%	0.00%	91.37%	91.37%	0.00%
Seasonal	74.63%	79.81%	5.18%	74.70%	79.85%	5.15%	76.77%	85.00%	8.23%
Street Lighting	44.00%	51.20%	7.20%	94.29%	94.29%	0.00%	97.20%	97.20%	0.00%

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 7 – Cost Allocation

IR Responses

1-Staff-1; 7-Staff-59; 7-Staff-60; 7-SEC-34; 7-VECC-34; 7-VECC-35; 7-VECC-36; 7-VECC-37; 7-VECC-38

Clarification Questions

PSC-VECC-48

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

5.2 Is the proposed rate design, including fixed/variable splits, appropriate?

Full Settlement

The Parties accept API's approach to rate design including the proposed fixed/variable splits. The proposed fixed/variable splits below reflect the Seasonal Class proposed rate mitigation under issue 5.6.

Table 11 – Summary of 2025 Fixed to Variable Split

Particulars	Original Application June 1, 2024	Original Application June 1, 2024	Original Application June 1, 2024	Response to IRs September 4, 2024	Response to IRs September 4, 2024	Response to IRs September 4, 2024	Settlement Proposal October 25, 2024	Settlement Proposal October 25, 2024	Settlement Proposal October 25, 2024
Customer Class	Fixed Rate	Variable Rate	TOTAL	Fixed Rate	Variable Rate	TOTAL	Fixed Rate	Variable Rate	TOTAL
Residential	100.00%	0.00%	100.00%	100.00%	0.00%	100.00%	100.00%	0.00%	100.00%
General Service < 50	23.25%	76.75%	100.00%	23.25%	76.75%	100.00%	23.80%	76.20%	100.00%
General Service > 50	24.53%	75.47%	100.00%	24.53%	75.47%	100.00%	26.27%	73.73%	100.00%
Seasonal	92.19%	7.81%	100.00%	92.19%	7.81%	100.00%	92.19%	7.81%	100.00%
Street Lighting	13.52%	86.48%	100.00%	13.52%	86.48%	100.00%	13.52%	86.48%	100.00%

Evidence References

- EXHIBIT 8 - Rate Design

IR Responses

1-Staff-1; 8-Staff-63; 8-VECC-39; 8-VECC-40

Clarification Questions

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

5.3 Are the proposed Retail Transmission Service Rates and Low Voltage rates appropriate?

Full Settlement

The Parties accept that the RTSR rates as updated and presented in Table 16 below are appropriate.

The Parties agree that should updated final or preliminary UTRs be issued prior to the issuance of a Decision in this matter, API will recalculate the RTSRs.

Table 12 - 2025 RTSR Network and Connection Rates Charges

		Original Application June 1, 2024	Response to IRs September 4, 2024	Settlement Proposal October 25, 2024
Transmission - Network				
Class Name	**Per**	**Rate $**	**Rate $**	**Rate $**
Residential	kWh	0.0092	0.0115	0.0115
General Service < 50 kW	kWh	0.0092	0.0115	0.0115
General Service > 50 kW	kW	3.5192	4.3825	4.3825
Seasonal	kWh	0.0092	0.0115	0.0115
Street Lighting	kW	2.5483	3.1734	3.1734
Transmission - Connection				
Class Name	**Per**			
Residential	kWh	0.0069	0.0081	0.0081
General Service < 50 kW	kWh	0.0069	0.0081	0.0081
General Service > 50 kW	kW	2.6105	3.0699	3.0699
Seasonal	kWh	0.0069	0.0081	0.0081
Street Lighting	kW	1.8832	2.2146	2.2146

Evidence References

- EXHIBIT 8 - Rate Design

IR Responses

1-Staff-1; 8-Staff-64; 8-VECC-43

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

5.4 Are the Proposed Loss Factors Appropriate?

Full Settlement

The Parties accept the proposed 2025 forecast loss factors as appropriate for the purpose of setting rates.

Table 13 - 2025 Loss Factors

	Original Application April 30, 2025	Response to IRs September 4, 2024	Variance over Original Application	Settlement Proposal October 25, 2024	Variance over IRs
Supply Facilities Loss Factor	1.0067	1.0067	0.0000	1.0067	0.0000
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0801	1.0801	0.0000	1.0801	0.0000
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0694	1.0694	0.0000	1.0694	0.0000
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0873	1.0873	0.0000	1.0873	0.0000
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0764	1.0764	0.0000	1.0765	0.0001

Evidence References

- EXHIBIT 8 – Rate Design

IR Responses

1-Staff-1; 8-Staff-66

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

5.5 Are the Specific Service Charges and Retail Service Charges appropriate?

Full Settlement

The Parties accept that API's proposed Specific Service Charges and Retail Service Charges are appropriate.

Evidence References

- EXHIBIT 8 - Rate Design

IR Responses

8-Staff-61; 8-VECC-44

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

5.6 Are rate mitigation proposals required and appropriate?

Full Settlement

The Parties agree to the rate mitigation proposal for the Seasonal rate class, specifically the delay in phasing in fixed monthly distribution. Specifically, API will maintain the existing fixed-variable split for the Seasonal class, despite the Board's policy to transition to fully fixed distribution rates, as a rate mitigation measure for customers at the 10th percentile of Seasonal consumption. In 2026 and beyond, API would propose to resume the transition to fully fixed rate, subject to the rate mitigation considerations in those future Applications.

With the changes made as a result of this Settlement Proposal, a phased-in adjustment of the Revenue to Cost ratio is no longer required, subject to further updates prior to the Board's Decision.

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 8 - Rate Design

IR Responses

1-Staff-1

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

5.7 Is the proposed request for Rural and Remote Rate Protection (RRRP) funding appropriate?

Full Settlement

The Parties agree that, within the context of the Settlement Proposal, API's request for RRRP funding of $19,749,782 (to be updated with any cost of capital parameter or cost of power changes) is appropriate, subject to the adjustment in 2025 only discussed in section 6.1, bringing the net RRRP requirement to $18,586,653.

Table 18 - 2025 Adjusted RRRP Requirement

RRRP Funding Requirement	$19,749,782
Adjustment for ACM True Up Disposition	-$1,163,128
Adjusted 2025 RRRP Funding	$18,586,653

The one-time adjustment for ACM True-Up will apply only in 2025, and has been calculated by allocating the ACM true up account among the classes based on Revenue Requirement. Only the RRRP-eligible class allocations [R1 (i), R1 (ii), and R2] of $1,163,128 have been included as RRRP offsets, with the remaining ACM true up allocation to be disposed of through Group 2 rate riders for the respective classes.

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 8 - Rate Design

IR Responses

1-Staff-1; 8-Staff-62; 8-VECC-39; 8-VECC-40; 8-VECC-42

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

5.8. Is Algoma's proposal to change the billing determinant for Street Lights from "connections" to "devices" appropriate?

Full Settlement

The Parties agree that API's proposal to change the billing determinant for Street Lights from "connections" to "devices" is appropriate, as outlined in Exhibit 8, Section 8.2.6.

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 8 - Rate Design, particularly section 8.2.6.

IR Responses

N/A

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

6. Deferral and Variance Accounts

6.1 Are the proposals for deferral and variance accounts other then Account 1588 and Account 1589, 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?

Full Settlement

The Parties agree that API's proposals for deferral and variance accounts, including the balances (as presented in Table 18 below) are appropriate, including the proposed disposition of those accounts on a final basis, subject to the following adjustments and comments:

a) The Parties agree to the proposed Pension Variance Account as proposed;

b) The Parties agree that the 2025 budget amounts for cloud computing related costs as set out in 4-STAFF-41 provide an appropriate baseline amount for cloud computing costs in relation to any future use of the Cloud Computing Implementation Cost Deferral Account;

c) The Parties agree that the 2025 budget amount for locates as set out in 9-Staff-74 provide an appropriate baseline amount of locate costs in relation to any future use of the Getting Ontario Connected Act Variance Account. API did not include any amounts in its budget (the baseline amount) to reflect the impact from Bill 93;

d) The Parties agree that API will establish a 1508 Sub-Account, #4 Circuit Section C-E Sale Deferral account to track the revenue requirement impact of the sale of any part of the #4 Circuit to a 3rd party, should such a sale occur. Please also see Section 1.2(b) for further background;

e) The Parties agree that $(1,163,051), which is the amount proposed to be credited to API's R1 and R2 customers in relation to the ACM rider revenue collected for the Sault St. Marie Facility and the Echo River TS will instead be credited to the RRRP program as an offset to the funding that API receives from the RRRP program in 2025. The amounts are further described under Issue 5.7. The derivation of the ACM true-up amount total of $1,307,910 (for RRRP and non-RRRP classes) is provided in the Application, section 9.3.12 ;

f) The Parties agree that a 1-year disposition period for all disposed of accounts is appropriate;

g) The Parties agree to the proposed Land Use Revenue Requirement Variance Account, subject to the account operating in the following fashion:

    i) The account will track variance in the revenue requirement related to API's land use rights costs in two separate sub-accounts, one for OM&A costs and one for capital related revenue requirement amounts,

    ii) the 2025 baseline OM&A amount will be $124,122,

iii) the baseline capital related revenue requirement amount will be 2,067,985[6], which includes the revenue requirement impact associated with the forecast $1M in 2024 in-service additions and $3.327M in 2025 in-service additions described under issues 1.1 and 1.2 respectively,

Table 19 – Calculation of Land Use RR VA Baseline

Land Use 2025 Test Year Revenue Requirement - Baseline				
OEB 1612				**2025T**
Fixed Asset Balances				
2024	40 Year	10 Year	Total	
Gross Fixed Assets - Opening	22,127,385	-	22,127,385	
Additions (Note 1)	1,400,424	-	1,400,424	
Gross Fixed Assets - Closing	23,527,809	-	23,527,809	
2025				
Gross Fixed Assets - Opening	23,527,809	-	23,527,809	23,527,809
Additions (Note 2)	3,009,755	542,000	3,551,755	
Gross Fixed Assets - Closing	26,537,564	542,000	27,079,564	27,079,564
2024				
Accumulated Amortization - Opening	(8,394,420)	-	(8,394,420)	
Amortization Expense (Note 3)	(583,394)	-	(583,394)	
Accumulated Amortization - Closing	(8,977,814)	-	(8,977,814)	
2025				
Accumulated Amortization - Opening	(8,977,814)	-	(8,977,814)	(8,977,814)
Amortization Expense (Note 4)	(639,996)	(27,100)	(667,096)	
Accumulated Amortization - Closing	(9,617,810)	(27,100)	(9,644,910)	(9,644,910)
2025 Average Fixed Asset Balances				
Net Book Value - Opening				14,549,995
Net Book Value - Closing				17,434,654
Net Book Value - Average				15,992,325

[6] Amount includes the $1.0M and $3.327M, as well as the originally proposed additions, per Application Appendix 2-BA, in USOA 1612 for 2024 (of $399,711) and 2025 (of $224,755). Capital Baseline Amount will be subject to update when the OEB issues its Cost of Capital parameters.

Land Use 2025 Test Year Revenue Requirement - Baseline					
OEB 1612					**2025T**
		Deemed %	Rate		
Short Term Debt (Note 5)		4.00%	6.23%		39,853
Long Term Debt		56.00%	5.12%		458,532
					498,385
Return on Equity (ROE) (Note 5)		40.00%	9.21%		589,157
Return on Rate Base		100.00%	6.80%		1,087,542
Grossed-up Taxes/PILS					
Regulatory Taxable Income (ROE)					589,157
Add: Amortization Expense					667,096
Less: CCA (Note 6)					(387,159)
Incremental Taxable Income					869,094
			Rate		
Taxes/PILs Before Gross-Up			26.50%		230,310
Grossed-Up Taxes/PILs					313,347
Baseline Revenue Requirement					
Return on Rate Base					1,087,542
Amortization Expense					667,096
Grossed-Up Taxes/PILs					313,347
IRR Total					2,067,985
Total 2025 Baseline Revenue Requirement					**2,067,985**
	Note 1	Sum of 2024 OEB 1612 $399,711 plus $713 ACM additions per 2-BA original application plus $1,000,000 per settlement.			
	Note 2	Sum of 2025 OEB 1612 $224,755 additions per 2-BA original application plus $3,327,000 per settlement.			
	Note 3	Sum of 2024 OEB 1612 ($570,856) plus ($430) ACM additions per 2-BA original application plus depreciation on additions per settlement.			
	Note 4	Sum of 2025 OEB 1612 ($580,183) additions per 2-BA original application plus depreciation on additions per settlement.			
	Note 5	Subject to change pending OEB update on cost of capital parameters			
	Note 6	2024 opening UCC specifically on OEB 1612 balances is not determinable, and would also have a $Nil impact on the future true-up of this account. Therefore, for simplicity, API set 2024 opening UCC value to Nil. See below for CCA calculation:			
		Class 47 CCA Rate		8%	
		2024			
		UCC - Opening		-	
		Additions (Note 1 exclude ACM)		1,399,711	
		CCA Deduction		(111,977)	
		UCC - Closing		1,287,734	
		2025			
		UCC - Opening		1,287,734	
		Additions (Note 2)		3,551,755	
		CCA Deduction		(387,159)	
		UCC - Closing		4,452,330	

iv) both accounts will track the cumulative annual variance between the noted base line amounts beginning in the 2025 test year through to and including API's next bridge year;

v) the actual OM&A amounts tracked in the OM&A sub-account will be API's actual Land Use Rights costs that are expensed by API in each year compared to the OM&A baseline amount from subsection ii) above;

vi) the actual capital related revenue requirement amounts tracked in the capital related revenue requirement sub-account will be the difference between the capital revenue requirement baseline and the total annual actual revenue requirement associated with API's capitalized Land Use Rights expenditures, including the related amortization expense (reflecting half year rule for new additions), weighted average cost of debt, return on equity, and related PILs expense, and including the recognition of the full year impact of Land Use Rights related in service additions in the second and subsequent years;

Please see the sample true-up calculation below for illustrative purposes only

Table 20 – Sample Entries- Land Use RR VA Capital Account

Land Use Revenue Requirement - Scenario Example True-up Calculation								
OEB 1612				**2025**	**2026**	**2027**	**2028**	**2029**
2024								
Accumulated Amortization - Opening	(8,394,420)	-	(8,394,420)					
Amortization Expense (Note 1)	(585,000)	-	(585,000)					
Accumulated Amortization - Closing	(8,979,420)	-	(8,979,420)					
2025								
Accumulated Amortization - Opening	(8,979,420)	-	(8,979,420)	(8,979,420)				
Amortization Expense (Note 1)	(628,000)	(25,000)	(653,000)					
Accumulated Amortization - Closing	(9,607,420)	(25,000)	(9,632,420)	(9,632,420)				
2026								
Accumulated Amortization - Opening	(9,607,420)	(25,000)	(9,632,420)		(9,632,420)			
Amortization Expense (Note 1)	(656,000)	(50,000)	(706,000)					
Accumulated Amortization - Closing	(10,263,420)	(75,000)	(10,338,420)		(10,338,420)			
2027								
Accumulated Amortization - Opening	(10,263,420)	(75,000)	(10,338,420)			(10,338,420)		
Amortization Expense (Note 1)	(659,000)	(50,000)	(709,000)					
Accumulated Amortization - Closing	(10,922,420)	(125,000)	(11,047,420)			(11,047,420)		
2028								
Accumulated Amortization - Opening	(10,922,420)	(125,000)	(11,047,420)				(11,047,420)	
Amortization Expense (Note 1)	(662,000)	(50,000)	(712,000)					
Accumulated Amortization - Closing	(11,584,420)	(175,000)	(11,759,420)				(11,759,420)	
2029								
Accumulated Amortization - Opening	(11,584,420)	(175,000)	(11,759,420)					(11,759,420)
Amortization Expense (Note 1)	(665,000)	(50,000)	(715,000)					
Accumulated Amortization - Closing	(12,249,420)	(225,000)	(12,474,420)					(12,474,420)
Average Fixed Asset Balances								
Net Book Value - Opening				14,647,965	16,494,965	15,988,965	15,479,965	14,967,965
Net Book Value - Closing				16,494,965	15,988,965	15,479,965	14,967,965	14,452,965
Net Book Value - Average				15,571,465	16,241,965	15,734,465	15,223,965	14,710,465

Land Use Revenue Requirement – Scenario Example True-up Calculation OEB 1612			2025	2026	2027	2028	2029
Scenario Example Land Use Revenue Requirement True-up Calculation							
Return on Rate Base							
	Deemed %	Rate					
Short Term Debt (Note 2)	4.00%	6.23%	38,804	40,475	39,210	37,938	36,658
Long Term Debt	56.00%	5.12%	446,465	465,690	451,139	436,502	421,778
			485,269	506,165	490,349	474,440	458,436
Return on Equity (ROE) (Note 2)	40.00%	9.21%	573,653	598,354	579,658	560,851	541,934
Return on Rate Base	100.00%	6.80%	1,058,922	1,104,519	1,070,007	1,035,291	1,000,370
Grossed-up Taxes/PILS							
Regulatory Taxable Income (ROE)			573,653	598,354	579,658	560,851	541,934
Add: Amortization Expense			653,000	706,000	709,000	712,000	715,000
Less: CCA (Note 3)			(310,400)	(301,568)	(293,443)	(261,967)	(257,010)
Incremental Taxable Income			916,253	1,002,786	995,215	1,010,884	999,924
		Rate					
Taxes/PILs Before Gross-Up		26.50%	242,807	265,738	263,732	267,884	264,980
Grossed-Up Taxes/PILs			330,350	361,548	358,819	364,468	360,517
Incremental Revenue Requirement							
Return on Rate Base			1,058,922	1,104,519	1,070,007	1,035,291	1,000,370
Amortization Expense			653,000	706,000	709,000	712,000	715,000
Grossed-Up Taxes/PILs			330,350	361,548	358,819	364,468	360,517
IRR Total			2,042,272	2,172,067	2,137,826	2,111,759	2,075,887
Total Scenario Revenue Requirement by Year			**2,042,272**	**2,172,067**	**2,137,826**	**2,111,759**	**2,075,887**
2025 Baseline Revenue Requirement			**2,067,985**	**2,067,985**	**2,067,985**	**2,067,985**	**2,067,985**
Difference (To be booked to DVA account)			**(25,713)**	**104,082**	**69,841**	**43,774**	**7,902**
			Cr to DVA	**Dr to DVA**	**Dr to DVA**	**Dr to DVA**	**Dr to DVA**

Note 1 Hypothetical scenario of OEB 1612 additions and amortization by year for demonstration purposes.

Note 2 Subject to change pending OEB update on cost of capital parameters

Note 3 2024 opening UCC specifically on OEB 1612 balances is not determinable, and would also have a $Nil impact on the future true-up of this account. Therefore, for simplicity, API set 2024 opening UCC value to Nil. See below for CCA calculation:

Class 47 CCA Rate	8%		
2024		**2027**	
UCC - Opening	-	UCC - Opening	3,468,032
Additions	1,500,000	Additions (Note 2)	200,000
CCA Deduction	(120,000)	CCA Deduction	(293,443)
UCC - Closing	1,380,000	UCC - Closing	3,374,589
2025		**2028**	
UCC - Opening	1,380,000	UCC - Opening	3,374,589
Additions (Note 2)	2,500,000	Additions (Note 2)	200,000
CCA Deduction	(310,400)	CCA Deduction	(261,967)
UCC - Closing	3,569,600	UCC - Closing	3,312,622
2026		**2029**	
UCC - Opening	3,569,600	UCC - Opening	3,312,622
Additions (Note 2)	200,000	Additions (Note 2)	200,000
CCA Deduction	(301,568)	CCA Deduction	(257,010)
UCC - Closing	3,468,032	UCC - Closing	3,255,613

vii) On clearing the OM&A sub account, API will clear 100% of the net cumulative OM&A account, whether it is a credit to be paid to customers or a debit to be collected from customers, subject to a prudence review;

viii) On clearing the capital related revenue requirement sub account, API will dispose of 100% of the net cumulative capital related revenue requirement if that net cumulative amount is a credit to customers, and 70% of the net cumulative capital related revenue requirement if that net cumulative amount is a debit to be recovered from customers, subject to a prudence review;

Table 21 - DVA Balances for Disposition

	Original Application April 30, 2025	Response to IRs September 4, 2024	Variance over Original Application	Settlement Proposal 25-Oct-24		Variance over IRs
Group 1						
Group 1 (excluding Account 1589)	$157,731	$157,731	$0	-$224,727	**	-$382,458
Account 1589 RSVA - Global Adjustment	-$292,802	-$292,802	$0	$0		$292,802
Total Group 1	**-$135,071**	**-$135,071**	$0	-$224,727	**	-$89,656
						$0
Group 2						$0
Pole Attachment Revenue Variance	$296,246	$296,246	$0	$295,304		-$942
Other Regulatory Assets - Sub-Account - Retail Service Charges	-$3,133	-$3,133	$0	-$3,123		$10
Other Regulatory Assets - Sub-Account - Amortized Pension Actuarial Gains/Losses	$226,148	$226,148	$0	$225,459		-$689
Other Regulatory Assets - Sub-Account - Amortized OPEB Actuarial Gains/Losses	-$258,334	-$258,334	$0	-$257,513		$821
Other Regulatory Assets, Sub-account ACM True-up	-$1,307,910.05	-$1,307,910.05	$0	-$1,307,910	*	-$0
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	-$313,498	-$313,498	$0	-$307,143		$6,355
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	-$286,716	-$286,716	$0	-$286,716		$0
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes12	-$310,790	-$302,140	$8,650	-$301,237		$903
Accounting Changes Under CGAAP Balance + Return Component	$84,971	$84,971	$0	$84,971		$0
DLI Account	-$27,311	-$27,311	$0	-$27,311	***	$0
Total Group 2 (incl. 1576)	**-$1,900,327**	**-$1,891,677**	$8,650	-$1,885,219		$6,458
Net Deferral Account Recovery	**-$2,035,397**	**-$2,026,747**	$8,650	**-$2,109,946**		-$83,198
* Balance of $(1.3M) will be partially disposed via RRRP rather than rate riders						
**Balances of $383,065 and $(292,802) for 1588 and 1589, respectively, have been excluded from proposed disposition pending OEB's Decision on Issue 6.2, which was excluded from Settlement in PO#1						
*** DLI Refunds being Disposed of outside DVA Model- to customers of in Township of Dubreuilville only.						

Table 22 - DVAs to Continue/Discontinue

Account Descriptions	Account Number	Continued or Discontinued
Group 2 Accounts		
Pole Attachment Revenue Variance	1508	Continued
Other Regulatory Assets - Sub-Account - Pension Deferral	1508	Continued
Other Regulatory Assets - Sub-Account - Pension Expense Variance	1508	Continued
Other Regulatory Assets - Sub-Account - Other Post Employment Benefits Deferral	1508	Continued
Other Regulatory Assets - Sub-Account - Other Post Employment Benefits Expense	1508	Continued
Other Regulatory Assets - Sub-Account - Dubreuilville Costs & Revenues	1508	Discontinued
Other Regulatory Assets - Sub-Account - Retail Service Charges	1508	Discontinued
Other Regulatory Assets - Sub-Account - Amortized Pension Actuarial Gains/Losses	1508	Continued
Other Regulatory Assets - Sub-Account - Amortized OPEB Actuarial Gains/Losses	1508	Continued
Other Regulatory Assets - Sub-Account - Defined Benefit Pension Variance Account	1508	New
Other Regulatory Assets - Sub-Account - #4 Circuit Section C-E Sale Deferral	1508	New
Other Regulatory Assets - Sub-Account - Land Use Revenue Requirement Variance Account	1508	New
Other Regulatory Assets, Sub-account Incremental Capital Expenditures - Sault Building	1508	Discontinued
Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues - Sault Building	1508	Discontinued
Other Regulatory Assets, Sub-account Incremental Capital Expenditures - Echo River	1508	Discontinued
Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues - Echo River	1508	Discontinued
Other Regulatory Assets, Sub-account ACM True-up	1508	Discontinued
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	1522	Continued
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	Continued
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes	1592	Continued
LRAM Variance Account	1568	Continued
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential	1522	Continued
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account	1522	Continued
Accounting Changes Under CGAAP Balance + Return Component	1576	Discontinued
Total Group 2 Accounts		

The eligibility criteria for the #4 Circuit Section C-E Sale Deferral Account is outlined below:

Causation:
The net value of the #4 Circuit Project, inclusive of Section C-E, has been added to rate base and included as part of the Test Year rate-setting calculations. Should a sale of this portion of the assets occur, this would create a variance outside the base upon which the rates were derived.

Materiality:
As outlined in the Clarification questions[7], the impact to rate base of the asset sale is estimated above $900,000, corresponding to the net book value of the assets in question at the time of sale.

Prudence:
The proposed variance account ensures that should an asset sale occur, a mechanism is in place to address the revenue requirement impact of the rate base reduction on customers' bills.

Evidence References

- EXHIBIT 1 – Administrative Documents
- EXHIBIT 9 – Deferral and Variance Accounts

IR Responses

Preamble, 9-Staff-69; 9-Staff-70; 9-Staff-72; 9-Staff-73; 9-Staff-74; 9-Staff-75; 9-Staff-76; 9-Staff-77; 9-SEC-35; 9-SEC-36; 9-SEC-37

Clarification Questions

PSC-SEC-38; PSC-SEC-41; PSC-SEC-43; PSC-VECC-49; PSC-Staff-1; PSC-Staff-8; PSC-Staff-9; PSC-Staff-12; PSC-Staff-13; PSC-Staff-14.

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

[7] Please see PSC-SEC-38.

6.2 Is the proposal for the disposition of Accounts 1588 and 1589, including the request for an order as per Section 36.1.1 of the Electricity Act, 1998 requiring the IESO to settle past Class A submissions appropriate?

Full Settlement

The Parties acknowledge that per the OEB's decision dated August 2, 2024 this issue is excluded from settlement.

Evidence References

9-Staff-71

IR Responses

Supporting Parties

- N/A for Settlement

7. Other

7.1 Is the proposed effective date appropriate?

Full Settlement

The Parties agree that API's new rates should be effective January 1, 2025. With respect to implementation, API's new rates can be implemented and effective as of January 1, 2025 were it to receive approval of the settlement proposal on or before January 17, 2025.

The Parties note that issue 6.2, which relates to the clearance of accounts 1588 and 1589, will be subject to a separate OEB approval process outside this Settlement Proposal. It is the Parties expectation that in the event the resolution of 6.2 is not concluded in time to implement a rider to clear accounts 1588 and 1589 for January 1, 2025, the OEB will provide directions on the clearance of any approved amounts as a result of the decision related to issue 6.2.

Evidence References

- EXHIBIT 1 – Administrative Documents

IR Responses

N/A

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

7.2 Has the applicant responded appropriately to all relevant OEB directions from previous proceedings?

Full Settlement

The Parties accept that API has responded appropriately to all outstanding OEB directions.

Evidence References

- EXHIBIT 1 – Administrative Documents

IR Responses

N/A

Supporting Parties

- VECC, SEC

Parties Taking No Position

- IESO

Settlement Proposal – Draft Accounting Orders

Algoma Power Inc.
EB-2024-0007

DRAFT ACCOUNTING ORDER - Defined Benefit Pension Plan Variance Account

Account 1508 - Other Regulatory Assets, Sub-Account API Defined Benefit Pension Plan Variance Account (ADBVA)

This account includes the variance between the Defined Benefit Pension Plan included in 2025 OM&A portion of the revenue requirement base rates ($25,579) and actuals during the subsequent IRM years. API will track costs at a sufficiently detailed level to assist in a prudence review of the costs incurred.

The following accounts are established to record the amounts described above incurred on or after January 1, 2025.

- Account 1508 - Other Regulatory Assets, API Defined Benefit Pension Plan (ADBVA)
- Account 1508 - Other Regulatory Assets, API Defined Benefit Pension Plan (ADBVA), Sub-Account Carrying Charges

Sample Journal Entries:

Revenue Requirement Variance

Entry below, to be booked by Dec 31st of each year starting in 2025 until next rebase, assumes proposed defined benefit amount attributed to OM&A in base rates is less than actual, entry flipped if proposed amount is greater than actual, entries expected to vary year-to-year.

Dr. Account 1508 - Other Regulatory Assets, API Defined Benefit Pension Plan (ADBVA)

Cr. 5645 Employee Pension and Benefits

To record pension OM&A expense variance between amount included in base rates and actual.

Carrying Charges (2025 Test Year to Next Rebase)

Entry below assumes net debit balance in Account 1508 - Other Regulatory Assets, ADBVA per above, entry flipped if net credit balance.

Dr. Account 1508 - Other Regulatory Assets, API Defined Benefit Pension Plan (ADBVA), Sub-Account Carrying Charges

Cr. 4405 Interest and Dividend Income

To record the carrying charges on the net monthly opening balance in Account 1508 - Other Regulatory Assets, API Defined Benefit Pension Plan (ADBVA), Sub-Account Carrying Charges.

Disposition – Future Proceeding

In a future Cost of Service proceeding, balances accumulated in the ADBVA 1508 accounts above will be requested for disposition, after which the approved balances will then be moved from the Sub-Accounts into a Group 2 1595 Sub-Account. Rate riders will be then applied against the accumulated balances to reduce the outstanding balance towards $Nil. Carrying charges will be recorded monthly on the outstanding principal balance using the prescribed interest rates set by the OEB until the balance is fully disposed.

DRAFT ACCOUNTING ORDER - #4 Circuit Section C-E Sale Deferral

Account 1508 - Other Regulatory Assets, Sub-Account API #4 Circuit Section C-E Sale Variance Account (ADBVA)

This account is to track the revenue requirement impact of the sale of any part of the #4 Circuit to a 3rd party, should such a sale occur. API will track costs at a sufficiently detailed level to assist in a prudence review of the costs incurred.

The following accounts are established to record the amounts described above incurred on or after January 1, 2025.

- Account 1508 - Other Regulatory Assets, API #4 Circuit Section C-E Sale Deferral (4CircuitC-E)
- Account 1508 - Other Regulatory Assets, API #4 Circuit Section C-E Sale Deferral (4CircuitC-E), Sub-Account Carrying Charges

Sample Journal Entries:

Revenue Requirement Variance

Entry below, to be booked by Dec 31st of each year starting in 2025 until next rebasing, assumes proposed sale resulted in an overcollection of revenue requirement due to overstatement of rate base in base rates following the sale of the assets.

Dr. Account 4080 Distribution Services Revenue

Cr. Account 1508 - Other Regulatory Assets, API #4 Circuit Section C-E Sale Deferral (4CircuitC-E)

To record revenue requirement impact of the sale of a part of the #4 Circuit Section C-E.

Carrying Charges (2025 Test Year to Next Rebasing)

Entry below assumes net debit balance in Account 1508 - Other Regulatory Assets, #4 Circuit Section C-E per above, entry flipped if net credit balance.

Dr. Account 6035 Other Interest Expense

Cr. Account 1508 - Other Regulatory Assets, API #4 Circuit Section C-E Sale Deferral (4CircuitC-E), Sub-Account Carrying Charges

To record the carrying charges on the net monthly opening balance in Account 1508 - Other Regulatory Assets, API #4 Circuit Section C-E Sale Deferral (4CircuitC-E), Sub-Account Carrying Charges.

Disposition – Future Proceeding

In a future Cost of Service proceeding, balances accumulated in the #4 Circuit Section C-E 1508 accounts above will be requested for disposition, after which the approved balances will then be moved from the Sub-Accounts into a Group 2 1595 Sub-Account. Rate riders will be then applied against the accumulated balances to reduce the outstanding balance towards $Nil. Carrying charges will be recorded monthly on the outstanding principal balance using the prescribed interest rates set by the OEB until the balance is fully disposed.

DRAFT ACCOUNTING ORDER - Land Use Revenue Requirement Variance Account

Account 1508 - Other Regulatory Assets, Sub-Account API Land Use Variance Account (ALUVA)

This account includes the variance between land use baseline related revenue requirement included in 2025 base rates (revenue requirement related to OEB 1612 capital component is $2,067,985, and OMA component in OEB 5095 is $124,122 in 2025 Test Year) and actual during the subsequent IRM years. API will track costs at a sufficiently detailed level to assist in a prudence review of the costs incurred.

The following accounts are established to record the amounts described above incurred on or after January 1, 2025 (including the 2025 revenue requirement impacts of capitalized agreements established in 2024).

- Account 1508 - Other Regulatory Assets, API Land Use Variance Account (ALUVA) OMA
- Account 1508 - Other Regulatory Assets, API Land Use Variance Account (ALUVA) Capital
- Account 1508 - Other Regulatory Assets, API Land Use Variance Account (ALUVA), Sub-Account Carrying Charges

Sample Journal Entries:

Revenue Requirement Variance (2025 Test Year to Next Rebase)

Entries below, to be booked by Dec 31st of each year starting in 2025 until next rebase, assumes proposed land use amount in base rates is less than actual, entry flipped if proposed amount is greater than actual, entries expected to vary year-to-year.

OMA

Dr. 1508 Other Regulatory Assets, API Land Use Variance Account (ALUVA) OMA

Cr. 4080 Distribution Services Revenue

To record variance between amount included in revenue requirement and actual for OMA.

Capital

Dr. 1508 Other Regulatory Assets, API Land Use Variance Account (ALUVA) Capital

Cr. 4080 Distribution Services Revenue

To record revenue requirement variance between amount included in base rates and actual for capital.

Note: The capital component would be calculated in accordance with revenue requirement calculation methodology and would include consideration for amortization expense, PILs, ROE and interest expense.

Carrying Charges (2025 Test Year Until Approved Disposition)

Entry below assumes net debit balance in Account 1508 - Other Regulatory Assets, ALUVA per above, entry flipped if net credit balance.

Dr. 1508 Other Regulatory Assets, API Land Use Variance Account (ALUVA) OMA, Sub-Account Carrying Charges

Dr. 1508 Other Regulatory Assets, API Land Use Variance Account (ALUVA) Capital, Sub-Account Carrying Charges

Cr. 4405 Interest and Dividend Income

To record the carrying charges on the net monthly opening balance in Account 1508 - Other Regulatory Assets, API Land Use Variance Accounts (ALUVA).

Disposition – Future Proceeding

In a future Cost of Service proceeding, balances accumulated in the ALUVA 1508 accounts above will be requested for disposition, after which the approved balances will then be moved from the Sub-Accounts into a Group 2 1595 Sub-Account. On the clearing of these 1508 Sub-Accounts to 1595 Sub-Account, API will dispose of 100% of the net cumulative capital related revenue requirement if that net cumulative amount is a credit pay-back to customers, and 70% of the net cumulative capital related revenue requirement if that net cumulative amount is a debit to be recovered from customers. Rate riders will be then applied against the accumulated balances to reduce the outstanding balance towards $Nil.
Carrying charges will be recorded monthly on the outstanding principal balance using the prescribed interest rates set by the OEB until the balance is fully disposed

Settlement Proposal – Revenue Requirement Work Form Excerpts

Algoma Power Inc.
EB-2024-0007

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Version 1.10

Utility Name	Algoma Power Inc.
Service Territory	*Algoma Area except SSM*
Assigned EB Number	EB-2024-0007
Name and Title	Oana Stefan, Manager, Regulatory Affairs
Phone Number	905-871-0330 x 3271
Email Address	regulatoryaffairs@fortisontario.com
Test Year	2025
Bridge Year	2024
Last Rebasing Year	2020

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.

Commencing with 2023 rate applications, the RRWF has been enhanced with an additional column, so that two stages of processing of an application (e.g. interrogatory responses and settlement agreement) between the initial application filing and the OEB decision and draft rate order ("Per Board Decision") can be used. Functionality of the RRWF is the same as in previous versions of the RRWF. (May 2022)

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 2025 Filers

Table of Contents

Notes:

(1) Pale green cells represent inputs

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

(3) Pale blue 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 2025 Filers

Data Input Sheet [1]

		Initial Application	[2]	Adjustments	Interrogatory Responses	[6]	Adjustments	Settlement Agreement	[6]	Adjustments	Per Board Decision
1	**Rate Base**										
	Gross Fixed Assets (average)	$ 272,738,705		$ -	$ 272,738,705		$1,713,500	$ 274,452,205			$ 274,452,205
	Accumulated Depreciation (average)	($98,625,717)	[5]	$ -	$ (98,625,717)		($29,220)	$ (98,654,937)			$ (98,654,937)
	Allowance for Working Capital:										
	Controllable Expenses	$16,579,014		$ -	$ 16,579,014		($970,787)	$ 15,608,227			$ 15,608,227
	Cost of Power	$32,534,015		$912,711	$ 33,446,726		($748,717)	$ 32,698,009			$ 32,698,009
	Working Capital Rate (%)	7.50%	[9]	0.00%	7.50%	[9]	0.00%	7.50%	[9]		[9]
2	**Utility Income**										
	Operating Revenues:										
	Distribution Revenue at Current Rates	$31,918,843		$0	$31,918,843		($629,328)	$31,289,516			
	Distribution Revenue at Proposed Rates	$35,112,551		($450,662)	$34,661,889		($929,342)	$33,732,547			
	Other Revenue:										
	Specific Service Charges	$90,000		$0	$90,000		$0	$90,000			
	Late Payment Charges	$40,000		$0	$40,000		$0	$40,000			
	Other Distribution Revenue	$499,000		($9,546)	$489,454		$140,000	$629,454			
	Other Income and Deductions	$27,000		$0	$27,000		$0	$27,000			
	Total Revenue Offsets	$656,000	[7]	($9,546)	$646,454		$140,000	$786,454			
	Operating Expenses:										
	OM+A Expenses	$16,319,014		$ -	$ 16,319,014		($970,787)	$15,348,227			$ 15,348,227
	Depreciation/Amortization	$5,675,782		$ -	$ 5,675,782		$72,329	$5,748,111			$ 5,748,111
	Property taxes	$260,000		$ -	$ 260,000		$ -	$260,000			$ 260,000
	Other expenses			$ -							
3	**Taxes/PILs**										
	Taxable Income:										
	Adjustments required to arrive at taxable income	($3,892,922)	[3]	$0	($3,892,922)		($47,991)	($3,940,913)			
	Utility Income Taxes and Rates:										
	Income taxes (not grossed up)	$704,131		$669	$704,800		$2,466	$707,266			
	Income taxes (grossed up)	$958,002			$958,912			$962,267			
	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										
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]		[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 (%)	5.59%		(0.47%)	5.12%		0.00%	5.12%			
	Short-term debt Cost Rate (%)	6.23%		0.00%	6.23%		0.00%	6.23%			
	Common Equity Cost Rate (%)	9.21%		0.00%	9.21%		0.00%	9.21%			
	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) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(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 or U12. 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. Beginning for 2023,two intermediate stages can be shown (e.g., Interrogatory Responses and Settlement Agreement).

(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 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 2025 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$272,738,705	$ -	$272,738,705	$1,713,500	$274,452,205	$ -	$274,452,205
2	Accumulated Depreciation (average)	(2)	($98,625,717)	$ -	($98,625,717)	($29,220)	($98,654,937)	$ -	($98,654,937)
3	Net Fixed Assets (average)	(2)	$174,112,988	$ -	$174,112,988	$1,684,280	$175,797,268	$ -	$175,797,268
4	Allowance for Working Capital	(1)	$3,683,477	$68,453	$3,751,931	($128,963)	$3,622,968	($3,622,968)	$ -
5	**Total Rate Base**		$177,796,465	$68,453	$177,864,919	$1,555,317	$179,420,236	($3,622,968)	$175,797,268

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$16,579,014	$ -	$16,579,014	($970,787)	$15,608,227	$ -	$15,608,227
7	Cost of Power		$32,534,015	$912,711	$33,446,726	($748,717)	$32,698,009	$ -	$32,698,009
8	Working Capital Base		$49,113,029	$912,711	$50,025,740	($1,719,504)	$48,306,236	$ -	$48,306,236
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%	-7.50%	0.00%
10	Working Capital Allowance		$3,683,477	$68,453	$3,751,931	($128,963)	$3,622,968	($3,622,968)	$ -

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 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 2025 Filers

Utility Income

Line No.	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:							
1	Distribution Revenue (at Proposed Rates)	$35,112,551	($450,662)	$34,661,889	($929,342)	$33,732,547	$ -	$33,732,547
2	Other Revenue (1)	$656,000	($9,546)	$646,454	$140,000	$786,454	$ -	$786,454
3	Total Operating Revenues	$35,768,551	($460,208)	$35,308,343	($789,342)	$34,519,000	$ -	$34,519,000
	Operating Expenses:							
4	OM+A Expenses	$16,319,014	$ -	$16,319,014	($970,787)	$15,348,227	$ -	$15,348,227
5	Depreciation/Amortization	$5,675,782	$ -	$5,675,782	$72,329	$5,748,111	$ -	$5,748,111
6	Property taxes	$260,000	$ -	$260,000	$ -	$260,000	$ -	$260,000
7	Capital taxes	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -		$ -	
9	Subtotal (lines 4 to 8)	$22,254,796	$ -	$22,254,796	($898,458)	$21,356,338	$ -	$21,356,338
10	Deemed Interest Expense	$6,005,731	($463,639)	$5,542,092	$48,462	$5,590,554	($112,888)	$5,477,666
11	Total Expenses (lines 9 to 10)	$28,260,527	($463,639)	$27,796,888	($849,996)	$26,946,892	($112,888)	$26,834,004
12	**Utility income before income taxes**	$7,508,024	$3,431	$7,511,455	$60,653	$7,572,108	$112,888	$7,684,996
13	Income taxes (grossed-up)	$958,002	$910	$958,912	$3,355	$962,267	$ -	$962,267
14	**Utility net income**	$6,550,022	$2,522	$6,552,543	$57,298	$6,609,842	$112,888	$6,722,730

Notes

		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$90,000	$ -	$90,000	$ -	$90,000		$90,000
	Late Payment Charges	$40,000	$ -	$40,000	$ -	$40,000		$40,000
	Other Distribution Revenue	$499,000	($9,546)	$489,454	$140,000	$629,454		$629,454
	Other Income and Deductions	$27,000	$ -	$27,000	$ -	$27,000		$27,000
	Total Revenue Offsets	$656,000	($9,546)	$646,454	$140,000	$786,454	$ -	$786,454

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Settlement Agreement	Per Board Decision
	Determination of Taxable Income				
1	Utility net income before taxes	$6,550,022	$6,552,544	$6,609,841	$6,476,371
2	Adjustments required to arrive at taxable utility income	($3,892,922)	($3,892,922)	($3,940,913)	($3,940,913)
3	Taxable income	$2,657,100	$2,659,622	$2,668,928	$2,535,458
	Calculation of Utility income Taxes				
4	Income taxes	$704,131	$704,800	$707,266	$707,266
6	Total taxes	$704,131	$704,800	$707,266	$707,266
7	Gross-up of Income Taxes	$253,871	$254,112	$255,001	$255,001
8	Grossed-up Income Taxes	$958,002	$958,912	$962,267	$962,267
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$958,002	$958,912	$962,267	$962,267
10	Other tax Credits	- $	- $	- $	$
	Tax Rates				
11	Federal tax (%)	15.00%	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 Filers

Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$99,566,021	5.59%	$5,562,662
2	Short-term Debt	4.00%	$7,111,859	6.23%	$443,069
3	**Total Debt**	60.00%	$106,677,879	5.63%	$6,005,731
	Equity				
4	Common Equity	40.00%	$71,118,586	9.21%	$6,550,022
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$71,118,586	9.21%	$6,550,022
7	**Total**	100.00%	$177,796,465	7.06%	$12,555,753

Interrogatory Responses

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$99,604,354	5.12%	$5,098,853
2	Short-term Debt	4.00%	$7,114,597	6.23%	$443,239
3	**Total Debt**	60.00%	$106,718,951	5.19%	$5,542,092
	Equity				
4	Common Equity	40.00%	$71,145,967	9.21%	$6,552,544
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$71,145,967	9.21%	$6,552,544
7	**Total**	100.00%	$177,864,919	6.80%	$12,094,636

Settlement Agreement

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
8	Long-term Debt	56.00%	$100,475,332	5.12%	$5,143,439
9	Short-term Debt	4.00%	$7,176,809	6.23%	$447,115
10	**Total Debt**	60.00%	$107,652,141	5.19%	$5,590,554
	Equity				
11	Common Equity	40.00%	$71,768,094	9.21%	$6,609,841
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$71,768,094	9.21%	$6,609,841
14	**Total**	100.00%	$179,420,236	6.80%	$12,200,396

Per Board Decision

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
8	Long-term Debt	56.00%	$98,446,470	5.12%	$5,039,580
9	Short-term Debt	4.00%	$7,031,891	6.23%	$438,087
10	**Total Debt**	60.00%	$105,478,361	5.19%	$5,477,666
	Equity				
11	Common Equity	40.00%	$70,318,907	9.21%	$6,476,371
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$70,318,907	9.21%	$6,476,371
14	**Total**	100.00%	$175,797,268	6.80%	$11,954,038

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2025 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	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$3,193,707		$2,743,045		$2,443,031		$3,569,424
2	Distribution Revenue	$31,918,843	$31,918,843	$31,918,843	$31,918,844	$31,289,516	$31,289,516	$31,289,516	$30,163,122
3	Other Operating Revenue Offsets - net	$656,000	$656,000	$646,454	$646,454	$786,454	$786,454	$786,454	$786,454
4	**Total Revenue**	$32,574,843	$35,768,551	$32,565,297	$35,308,343	$32,075,969	$34,519,000	$32,075,969	$34,519,000
5	Operating Expenses	$22,254,796	$22,254,796	$22,254,796	$22,254,796	$21,356,338	$21,356,338	$21,356,338	$21,356,338
6	Deemed Interest Expense	$6,005,731	$6,005,731	$5,542,092	$5,542,092	$5,590,554	$5,590,554	$5,477,666	$5,477,666
8	**Total Cost and Expenses**	$28,260,527	$28,260,527	$27,796,888	$27,796,888	$26,946,892	$26,946,892	$26,834,004	$26,834,004
9	**Utility Income Before Income Taxes**	$4,314,316	$7,508,024	$4,768,409	$7,511,455	$5,129,077	$7,572,108	$5,241,965	$7,684,996
10	Tax Adjustments to Accounting Income per 2013 PILs model	($3,892,922)	($3,892,922)	($3,892,922)	($3,892,922)	($3,940,913)	($3,940,913)	$ -	($3,940,913)
11	**Taxable Income**	$421,394	$3,615,102	$875,487	$3,618,533	$1,188,164	$3,631,195	$5,241,965	$3,744,083
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$111,670	$958,002	$232,004	$958,911	$314,864	$962,267	$1,389,121	$992,182
14	**Income Tax Credits**	- $	- $	- $	- $	- $	$		
15	**Utility Net Income**	$4,202,647	$6,550,022	$4,536,405	$6,552,543	$4,814,214	$6,609,842	$3,852,845	$6,722,730
16	**Utility Rate Base**	$177,796,465	$177,796,465	$177,864,919	$177,864,919	$179,420,236	$179,420,236	$175,797,268	$175,797,268
17	Deemed Equity Portion of Rate Base	$71,118,586	$71,118,586	$71,145,967	$71,145,967	$71,768,094	$71,768,094	$70,318,907	$70,318,907
18	Income/(Equity Portion of Rate Base)	5.91%	9.21%	6.38%	9.21%	6.71%	9.21%	5.48%	9.56%
19	Target Return - Equity on Rate Base	9.21%	9.21%	9.21%	9.21%	9.21%	9.21%	9.21%	9.21%
20	Deficiency/Sufficiency in Return on Equity	-3.30%	0.00%	-2.83%	0.00%	-2.50%	0.00%	-3.73%	0.35%
21	Indicated Rate of Return	5.74%	7.06%	5.67%	6.80%	5.80%	6.80%	5.31%	6.94%
22	Requested Rate of Return on Rate Base	7.06%	7.06%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%
23	Deficiency/Sufficiency in Rate of Return	-1.32%	0.00%	-1.13%	0.00%	-1.00%	0.00%	-1.49%	0.14%
24	Target Return on Equity	$6,550,022	$6,550,022	$6,552,544	$6,552,544	$6,609,841	$6,609,841	$6,476,371	$6,476,371
25	Revenue Deficiency/(Sufficiency)	$2,347,375	$ -	$2,016,138	($0)	$1,795,628	$0	$2,623,527	$246,358
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,193,707 [1]		$2,743,045 [1]		$2,443,031 [1]		$3,569,424 [1]	

Notes:

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

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Revenue Requirement Workform (RRWF) for 2025 Filers

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Settlement Agreement		Per Board Decision
1	OM&A Expenses	$16,319,014		$16,319,014		$15,348,227		$15,348,227
2	Amortization/Depreciation	$5,675,782		$5,675,782		$5,748,111		$5,748,111
3	Property Taxes	$260,000		$260,000		$260,000		$260,000
5	Income Taxes (Grossed up)	$958,002		$958,912		$962,267		$962,267
6	Other Expenses	$ -						
7	Return							
	Deemed Interest Expense	$6,005,731		$5,542,092		$5,590,554		$5,477,666
	Return on Deemed Equity	$6,550,022		$6,552,544		$6,609,841		$6,476,371
8	**Service Revenue Requirement (before Revenues)**	$35,768,551		$35,308,343		$34,519,000		$34,272,642
9	Revenue Offsets	$656,000		$646,454		$786,454		$ -
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$35,112,551		$34,661,889		$33,732,546		$34,272,642
11	Distribution revenue	$35,112,551		$34,661,889		$33,732,547		$33,732,547
12	Other revenue	$656,000		$646,454		$786,454		$786,454
13	**Total revenue**	$35,768,551		$35,308,343		$34,519,000		$34,519,000
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	($0)	(1)	$0	(1)	$246,358 (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Interrogatory Responses	Δ% (2)	Settlement Agreement	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$35,768,551	$35,308,343	###	$34,519,000	(3.49%)	$34,272,642	(4.18%)
Grossed-Up Revenue Deficiency/(Sufficiency)	$3,193,707	$2,743,045	###	$2,443,031	(23.50%)	$3,569,424	11.76%
Base Revenue Requirement (to be recovered from Distribution Rates)	$35,112,551	$34,661,889	###	$33,732,546	(3.93%)	$34,272,642	(2.39%)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$3,193,707	$2,743,046	###	$2,443,031	(23.50%)	$ -	(100.00%)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

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Revenue Requirement Workform (RRWF) for 2025 Filers

Load Forecast Summary

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

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

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

Stage in Process: Settlement Agreement

	Customer Class	Initial Application			Interrogatory Responses			Settlement Agreement			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual
1	Residential	9,674	131,653,365		9,674	131,653,365		9,705	128,336,485				
2	Residential R2	45	179,389,418	372,457	45	179,389,418	372,457	46	172,482,673	345,623			
3	Seasonal	2,717	5,958,052		2,717	5,958,052	-	2,719	5,961,327				
4	Street Light	1,156	548,977	1,533	1,156	548,977	1,533	1,129	536,180	1,497			
5													
6													
7													
8													
9													
10													
11													
12													
13													
14													
15													
16													
17													
18													
19													
20													
	Total	**13592.26904**	**317,549,813**	**373,990**		**317,549,813**	**373,990**		**307,316,665**	**347,120**			

Notes:

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

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Revenue Requirement Workform (RRWF) for 2025 Filers

Cost Allocation and Rate Design

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

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

A) Allocated Costs

	Name of Customer Class (3) From Sheet 10. Load Forecast	Costs Allocated from Previous Study (1)	%	Allocated Class Revenue Requirement (1) (7A)	%
1	Residential	$ 16,904,988	66.27%	$ 21,667,340	62.77%
2	Residential R2	$ 5,043,434	19.77%	$ 8,354,838	24.20%
3	Seasonal	$ 3,391,922	13.30%	$ 4,258,849	12.34%
4	Street Light	$ 169,968	0.67%	$ 237,974	0.69%
	Total	$ 25,510,312	100.00%	**$ 34,519,000**	100.00%
		Service Revenue Requirement (from Sheet 9)		**$ 34,519,000.32**	

(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	$ 21,208,219	$ 22,864,120	$ 22,513,464	$ 519,971
2	Residential R2	$ 6,942,904	$ 7,484,994	$ 7,484,994	$ 149,230
3	Seasonal	$ 2,930,003	$ 3,158,772	$ 3,509,428	$ 110,593
4	Street Light	$ 208,390	$ 224,661	$ 224,661	$ 6,660
	Total	$ 31,289,516	$ 33,732,547	$ 33,732,547	$ 786,454

(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.
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.
(6)
(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: 2020	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential	104.65%	107.92%	106.30%	85 - 115
2	Residential R2	93.54%	91.37%	91.37%	80 - 120
3	Seasonal	85.44%	76.77%	85.00%	85 - 115
4	Street Light	120.00%	97.20%	97.20%	80 - 120

(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 2020 with further adjustments to move within the range over two years, the Most Recent Year would be 2023. However, the ratios in 2023 would be equal to those after the adjustment in 2022.

(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		
		2025	2026	2027	
1	Residential	106.30%	106.30%	106.30%	85 - 115
2	Residential R2	91.37%	91.37%	91.37%	80 - 120
3	Seasonal	85.00%	85.00%	85.00%	85 - 115
4	Street Light	97.20%	97.20%	97.20%	80 - 120

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2025 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 2026 and 2027 Price Cap IR models, as necessary. For 2026 and 2027, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2026 (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'.

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Revenue Requirement Workform (RRWF) for 2025 Filers

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Seasonal Class	
Customers	2,719
kWh	5,961,327

Proposed seasonal Class Specific Revenue Requirement[1]	$ 3,509,428.03

Seasonal Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 82.79
Distribution Volumetric Rate ($/kWh)	$ 0.0384

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	82.79	2,719	$ 2,701,087.84	92.19%
Variable	0.0384	5,961,327	$ 228,914.97	7.81%
TOTAL	-	-	$ 2,930,002.81	-

C Calculating Test Year Base Rates

Maximum Increase per Year Due to Residential Rate Design Policy	$ -

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 3,235,243.78	99.16	$ 3,235,171.76
Variable	$ 274,184.25	0.046	$ 274,221.06
TOTAL	$ 3,509,428.03	-	$ 3,509,392.82

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	92.19%	$ 3,235,171.76	$ 99.16	$ 3,235,171.76
Variable	7.81%	$ 274,256.27	$ 0.0460	$ 274,221.06
TOTAL	-	$ 3,509,428.03	-	$ 3,509,392.82

Checks[3]	
Change in Fixed Rate	$ -
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	($35.21) 0.00%

Notes:

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

[2] The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. The change in residential rate design is almost complete and distributors should have either 0 or 1 year remaining. If the distributor has fully transitioned to fixed rates put "0" in cell D40. If the distributor has proposed an additional transition year because the change in the residential rate design will result in the fixed charge increasing by more than $4/year, put "1" in cell D40.

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

RRRP Adjustments Factor for Test Year 4.75%

	Current Approved 2024 Rates		
	Vol. Billing Unit	Monthly	Volumetric
Residential R1(i)	kWh	$ 64.31	$ -
Residential R1(ii)	kWh	$ 28.84	$ 0.0406
Residential R2	kW	$ 742.06	$ 3.8450

	RRRP Adjusted 2025 Rates		
	Vol. Billing Unit	Monthly	Volumetric
Residential R1(i)	kWh	$ 67.36	$ -
Residential R1(ii)	kWh	$ 30.21	$ 0.0425
Residential R2	kW	$ 777.31	$ 4.0276

	2025 Forecasted Billing Units		
	Vol. Billing Unit	Customers	Volume
Residential R1(i)	kWh	8,635	99,118,975
Residential R1(ii)	kWh	1,071	29,217,510
Residential R2	kW	46	345,623
Total		9,752	

	2025 Forecasted Revenue from Rates				
	Vol. Billing Unit	Fixed	Volumetric	Transformer Allowance	Total Revenues
Residential R1(i)	kWh	$ 6,980,240	$ -	$ -	**$ 6,980,240**
Residential R1(ii)	kWh	$ 388,098	$ 1,242,577	$ -	**$ 1,630,674**
Residential R2	kW	$ 430,190	$ 1,392,042	-$ 184,470	**$ 1,637,762**
Total		$ 7,798,527	$ 2,634,619	-$ 184,470	**$ 10,248,676**

	Allocated Base Revenue
Residential R1(i) Residential R1(ii)	$ 22,513,464
Residential R2	$ 7,484,994
Total	$ 29,998,458
Total Revenue Requirement from RRRP Classes	$ 29,998,458
Less: Revenue From RRRP Reduced Rates	$ 10,248,676
Proposed 2025 Annual RRRP Funding- 2025 Test Year	**$ 19,749,782**
2025 ACM True Up Disposition to RRRP (One time ajdustment)	-$ 1,163,128
Adjusted 2025 RRRP Funding	**$ 18,586,653**

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Revenue Requirement Workform (RRWF) for 2025 Filers

Rate Design and Revenue Reconciliation

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

Stage in Process: *Settlement Agreement*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2,3] (Percentage to be entered as a fraction between 0 and 1)			Distribution Rates: Monthly Service Charge [2]		Distribution Rates: Volumetric Rate [3]			Revenue Reconciliation		
	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] ($)	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential R1(i)	kWh	8,635	99,118,975	-	$ 6,980,240	$ 6,980,240	$ -	100.00%	0.00%		$67.36	2	$0.0000	/kWh	4	$ 6,979,750.19	$ -	$ 6,979,750.19
	Residential R1(ii)	kWh	1,071	29,217,510	-	$ 1,630,674	$ 388,098	$ 1,242,577	23.80%	76.20%		$30.21	2	$0.0425	/kWh	4	$ 388,098.82	$ 1,241,744.1802	$ 1,629,843.00
2	Residential R2	kW	46	172,482,673	345,623	$ 1,637,762	$ 430,190	$ 1,207,572	26.27%	73.73%	$ 184,470	$777.31		$4.0276	/kW		$ 430,191.16	$ 1,392,029.1975	$ 1,637,749.98
3	Seasonal	kWh	2,719	5,961,327	-	$ 3,509,428	$ 3,235,172	$ 274,256	92.19%	7.81%		$99.16		$0.0460	/kWh		$ 3,235,171.76	$ 274,221.0603	$ 3,509,392.82
4	Street Light	kWh	1,129	536,180	1,497	$ 224,661	$ 30,374	$ 194,287	13.52%	86.48%		$2.24		$0.3624	/kWh		$ 30,347.60	$ 194,311.7035	$ 224,659.31
5	RRRP	kWh	0	0	-	$ 19,749,782	$ 19,749,782	$ -	100.00%	0.00%		$19,749,781.71		$0.0000	/kWh		$ 19,749,781.71	$ -	$ 19,749,781.71
6			-	-	-												$ -	$ -	$ -
7			-	-	-												$ -	$ -	$ -
8			-	-	-												$ -	$ -	$ -
9			-	-	-												$ -	$ -	$ -
10			-	-	-												$ -	$ -	$ -
11			-	-	-												$ -	$ -	$ -
12			-	-	-												$ -	$ -	$ -
13			-	-	-												$ -	$ -	$ -
14			-	-	-												$ -	$ -	$ -
15			-	-	-												$ -	$ -	$ -
16			-	-	-												$ -	$ -	$ -
17			-	-	-												$ -	$ -	$ -
18			-	-	-												$ -	$ -	$ -
19			-	-	-												$ -	$ -	$ -
20			-	-	-												$ -	$ -	$ -
			13,599	307,316,665	347,120	$ 33,732,547													

Total Transformer Ownership Allowance $ 184,470

Total Distribution Revenues	$ 33,731,177.01
Base Revenue Requirement	$ 33,732,546.36
Difference	-$ 1,369.35
% Difference	-0.004%

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).

3 The Volumetric rate is calculated as [(allocated volumetric revenue requirement for the class + transformer allowance credit for the class)/(annual estimate of the charge determinant for the test year (either kW or kVA for demand-billed customer classes, or kWh for non-demand-billed classes)]

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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	$ 12,555,753	7.06%	$ 177,796,465	$ 49,113,029	$ 3,683,477	$ 5,675,782	$ 958,002	$ 16,319,014	$ 35,768,551	$ 656,000	$ 35,112,551	$ 3,193,707
1	8-Staff-64 & 8-VECC-43	Interrogatories- Update COP/WCA/Rate Base for RTSR	$ 12,560,587	7.06%	$ 177,864,919	$ 50,025,740	$ 3,751,931	$ 5,675,782	$ 958,002	$ 16,319,014	$ 35,773,385	$ 656,000	$ 35,117,385	$ 3,199,451
		Change	$ 4,834	0.00%	$ 68,454	$ 912,711	$ 68,453	$ -	$ -	$ -	$ 4,834	$ -	$ 4,834	$ 5,743
2	8-Staff-61/8-VECC-45	Update Revenue Offsets for Pole Att. Fee (inflation)	$ 12,560,587	7.06%	$ 177,864,919	$ 50,025,740	$ 3,751,931	$ 5,675,782	$ 958,002	$ 16,319,014	$ 35,773,385	$ 646,454	$ 35,126,931	$ 3,208,997
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 9,546	$ 9,546	$ 9,546
3	5-Staff-52	Update Cost of Capital for Updated LTD	$ 12,094,636	6.80%	$ 177,864,919	$ 50,025,740	$ 3,751,931	$ 5,675,782	$ 958,912	$ 16,319,014	$ 35,308,343	$ 646,454	$ 34,661,889	$ 2,743,045
		Change	-$ 465,951	-0.26%	$ -	$ -	$ -	$ -	$ 910	$ -	-$ 465,042	$ -	-$ 465,042	-$ 465,951
4	Settlement X	Reduce OMA $327,000	$ 12,092,968	6.80%	$ 177,840,394	$ 49,698,740	$ 3,727,406	$ 5,675,782	$ 958,585	$ 15,992,014	$ 34,979,349	$ 646,454	$ 34,332,895	$ 2,414,052
		Change	-$ 1,668	0.00%	-$ 24,525	-$ 327,000	-$ 24,525	$ -	-$ 327	-$ 327,000	-$ 328,994	$ 0	-$ 328,994	-$ 328,993
5	Settlement X.1	Reduce OMA $643,787 land use	$ 12,089,685	6.80%	$ 177,792,110	$ 49,054,953	$ 3,679,121	$ 5,675,782	$ 957,944	$ 15,348,227	$ 34,331,638	$ 646,454	$ 33,685,184	$ 1,766,340
		Change	-$ 3,283	0.00%	-$ 48,284	-$ 643,787	-$ 48,285	$ -	-$ 641	-$ 643,787	-$ 647,711	$ -	-$ 647,711	-$ 647,712
6	Settlement X.2	Increase Oth Rev $140,000	$ 12,089,685	6.80%	$ 177,792,110	$ 49,054,953	$ 3,679,121	$ 5,675,782	$ 957,944	$ 15,348,227	$ 34,331,638	$ 786,454	$ 33,545,184	$ 1,626,340
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 140,000	-$ 140,000	-$ 140,000
7	Settlement X.3	Land use $1,000,000 capital addition 2024, $3,327,000 capital additional 2025	$ 12,266,995	6.80%	$ 180,399,654	$ 49,054,953	$ 3,679,121	$ 5,762,694	$ 901,416	$ 15,348,227	$ 34,539,332	$ 786,454	$ 33,752,878	$ 1,834,035
		Change	$ 177,310	0.00%	$ 2,607,544	$ -	$ -	$ 86,912	-$ 56,528	$ -	$ 207,694	$ -	$ 207,694	$ 207,695
8	Settlement X.4	Shift $400,000 from 2024 capital additions to 2025, then reduce 2025 capital additions by $1,500,000.	$ 12,204,214	6.80%	$ 179,476,390	$ 49,054,953	$ 3,679,121	$ 5,748,111	$ 963,012	$ 15,348,227	$ 34,523,564	$ 786,454	$ 33,737,110	$ 1,818,267
		Change	-$ 62,781	0.00%	-$ 923,264	$ -	$ -	-$ 14,583	$ 61,596	$ -	-$ 15,768	$ -	-$ 15,768	-$ 15,768
9	Settlement X.4	load forecast change & Nov 1'24 RPP/OER Update	$ 12,200,396	6.80%	$ 179,420,236	$ 179,420,236	$ 3,622,968	$ 5,748,111	$ 962,267	$ 15,348,227	$ 34,519,000	$ 786,454	$ 33,732,547	$ 2,443,031
		Change	-$ 3,818	0.00%	-$ 56,154	$ 130,365,283	-$ 56,153	-$ 0	-$ 745	$ 0	-$ 4,564	-$ 0	-$ 4,563	$ 624,764

Settlement Proposal – Chapter 2 Appendix Excerpts

Algoma Power Inc.
EB-2024-0007

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Net Capital/Gross Capital	

Appendix 2-AA
Capital Projects Table

Projects	2020	2021	2022	2023	2024 Bridge Year	2025 Test Year	2026	2027	2028	2029
Reporting Basis	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE
System Access										
Meters	$ 302,112	$ 83,982	$ 137,956	$ 110,307	$ 132,952	$ 129,294	$ 131,246	$ 133,214	$ 135,213	$ 137,241
Service Connections	$ 981,859	$ 1,506,238	$ 1,284,929	$ 12,463,740	$ 2,998,014	$ 1,090,988	$ 1,167,403	$ 1,184,913	$ 1,202,686	$ 1,220,728
Transformers - SA	$ 51,982	$ 248,886	$ 278,992	$ 317,632	$ 154,000	$ 110,000	$ 162,400	$ 164,836	$ 167,309	$ 169,818
Relocation/Joint-Use	$ 182,808	$ 648,395	$ 380,336	$ 97,786	$ 10,000	$ 25,000	$ 28,114	$ 28,536	$ 28,964	$ 29,398
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
System Access Gross Expenditures	1,518,760	2,487,501	2,082,212	12,989,466	3,294,967	1,355,281	1,489,163	1,511,499	1,534,172	1,557,185
System Access Capital Contributions	144,984	472,311	33,820	141,704	5,252,085	100,000	102,000	104,040	106,121	108,243
Sub-Total	1,373,776	2,015,190	2,048,392	12,847,762	-1,957,118	1,255,281	1,387,163	1,407,459	1,428,051	1,448,942
System Renewal										
Storm Capital	$ 78,102	$ 100,323	$ 37,690	$ 16,323	$ -	$ -	$ -	$ -	$ -	$ -
Small Lines/Station Capital	$ 484,152	$ 317,612	$ 381,283	$ 385,481	$ 423,625	$ 430,224	$ 435,523	$ 441,854	$ 448,277	$ 454,793
Recloser, Regulator Replacements	$ 65,673	$ -	$ 16,219	$ 48,785	$ 62,100	$ 50,000	$ 91,350	$ 92,720	$ 94,111	$ 95,523
Distribution Line Rebuilds	$ 3,198,061	$ 4,364,427	$ 4,234,143	$ 3,153,365	$ 5,454,691	$ 3,300,947	$ 3,765,636	$ 3,822,121	$ 3,879,452	$ 3,937,644
Subtransmission Line Rebuilds	$ 57,830	$ 206,603	$ 11	$ 249,775	$ 1,594,380	$ 1,084,493	$ 977,272	$ 991,932	$ 1,006,811	$ 1,021,913
Transformers - SR	$ 157,891	$ 150,133	$ 74,390	$ 225,373	$ 116,800	$ 90,000	$ 142,100	$ 144,232	$ 146,395	$ 148,591
Dubreuilville DS Rebuild	10,088	$ -	$ 2,823,393	$ 22,757	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Replacements	$ -	$ -	$ -	$ -	$ -	$ 406,509	$ 410,468	$ 416,625	$ 422,875	$ 429,218
Bruce Mines DS Rebuild	$ -	$ -	$ -	-$ 0	$ 4,345,863	$ -	$ -	$ -	$ -	$ -
Wawa #2 DS Rebuild	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,584,465	$ -	$ -
System Renewal Gross Expenditures	4,051,798	5,139,098	7,567,129	4,101,859	11,997,459	5,362,173	5,822,349	10,493,949	5,997,921	6,087,682
System Renewal Capital Contributions	$ 23,480	$ -	$ 2,024	$ 31,153	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total	4,028,318	5,139,098	7,565,105	4,070,705	11,997,459	5,362,173	5,822,349	10,493,949	5,997,921	6,087,682
System Service										
Transformers - SS	$ -	$ 115,963	$ 30,979	$ 179,697	$ 55,000	$ -	$ -	$ -	$ -	$ -
Hawk Junction DS	$ -	$ 856,045	$ 699	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Goulais Voltage Conversion	$ -	$ -	$ -	$ -	$ -	$ 296,560	$ 302,370	$ 308,417	$ 314,586	$ 320,877
Protection, Automation, Reliability	$ 255,092	$ 8,118	$ -	$ 11,213,244	$ 1,484,971	$ 757,301	$ 807,144	$ 343,918	$ 437,971	$ 309,491
Desbarats DS Upgrades	$ 3,487	$ -	$ -	-$ 0	$ 143,911	$ -	$ -	$ -	$ -	$ -
Goulais TS Refurbishment	$ -	$ -	$ -	-$ 0	$ 0	$ -	$ -	$ -	$ -	$ 680,000
System Service Gross Expenditures	258,579	980,125	31,678	11,392,940	1,683,882	1,053,861	1,109,514	652,335	752,557	1,310,368
System Service Capital Contributions	0	0	227,852	98,993	0	0	0	0	0	0
Sub-Total	258,579	980,125	-196,174	11,293,947	1,683,882	1,053,861	1,109,514	652,335	752,557	1,310,368
General Plant										
ROW Expansion	$ 105,630	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tools & Equipment	$ 29,186	$ 83,318	$ 59,546	$ 164,421	$ 90,000	$ 91,800	$ 93,177	$ 94,575	$ 95,993	$ 97,433
Business Systems	$ -	$ 15,575	$ 9,179	$ 66,409	$ 485,448	$ 82,437	$ 83,479	$ 84,731	$ 86,002	$ 87,292
Land Rights	$ 29,425	$ 62,085	$ 63,601	$ 76,710	$ 1,039,336	$ 3,360,420	$ 33,783	$ 34,290	$ 34,804	$ 35,326
Communication & SCADA	$ -	$ -	$ -	$ -	$ -	$ 125,564	$ 146,127	$ 138,210	$ 70,487	$ -
Transportation & Work Equipment	$ 784,824	$ 499,513	$ 138,882	$ 1,145,318	$ 584,674	$ 607,470	$ 957,509	$ 1,139,721	$ 1,129,936	$ 1,189,752
IT Hardware/Software	$ 61,070	$ 124,961	$ 240,475	$ 106,934	$ 58,933	$ 59,067	$ 59,824	$ 60,722	$ 61,632	$ 62,556
Buildings, Facilities & Yards	$ 135,485	$ 53,185	$ 165,728	$ 25,498	$ 154,147	$ 213,866	$ 216,898	$ 173,934	$ 176,542	$ 179,191
Sault Facility	$ -	$ -	$ 15,708,824	$ 640,323	$ 200,622	$ -	$ -	$ -	$ -	$ -
ROW Access Program	$ 279,359	-$ 19,969	$ -	$ 15,000	$ 288,217	$ 225,549	$ 127,295	$ 129,204	$ 131,142	$ 133,109
General Plant Gross Expenditures	1,424,978	818,668	16,386,235	2,240,612	2,901,377	4,766,174	1,718,092	1,855,387	1,786,538	1,784,659
General Plant Capital Contributions	0	0	0	0	0	0	0	0	0	0
Sub-Total	1,424,978	818,668	16,386,235	2,240,612	2,901,377	4,766,174	1,718,092	1,855,387	1,786,538	1,784,659
Miscellaneous										
Total	**7,085,650**	**8,953,081**	**25,803,557**	**30,453,026**	**14,625,599**	**12,437,489**	**10,037,118**	**14,409,130**	**9,965,067**	**10,631,651**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***										
Total	**7,085,650**	**8,953,081**	**25,803,557**	**30,453,026**	**14,625,599**	**12,437,489**	**10,037,118**	**14,409,130**	**9,965,067**	**10,631,651**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

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Capital Expnditures = In Service Additions	

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:

2025

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2020			2021			2022			2023			2024			2025	2026	2027	2028	2029
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access			68.1%			158.2%			123.8%	906		1333.1%			263.5%					1,557
System Renewal			-32.7%			9.3%			56.9%			-36.8%		3,295	159.9%	1,355	1,489	1,511		
System Service	903 6,023	1,519	-54.0%	963 4,700	2,488	-87.7%		2,082	-93.3%	6,494	12,989	2371.9%	906 4,616	11,997	265.3%	5,362	5,822	10,494	1,534	6,088 8,310
General Plant		4,052	5.0%	7,978	5,139	-33.9%	930 4,822	7,567	17.2%	461	4,102	90.2%		1,684	164.3%	1,054	1,110		5,998	
TOTAL EXPENDITURE	562 1,357		-18.0%	1,238		-36.7%			29.0%	1,178	11,393	239.9%	461 1,098	2,901	180.7%	4,766	1,718	652 1,855	753	1,785
Capital Contributions	-8,846 102	259 1,425 168	65.4%	-14,879 100	980 - 472	372.3%	-472 13,980 100	16,386 32 264	163.7%	-9,039	- 2,241 30,725 272	171.8%	-7,081 100	-19,878 5,252	5152.1%	-12,537 100	-10,139 102	-14,513 104	1,787 -10,071 106	-10,740
NET CAPITAL EXPENDITURES		7,254	-19.0%	14,779	819 9,425	-39.4%	20,205	26,067	28.3%	100		240.7%			109.5%					108
System O&M	8,744 $ 7,015	$ 7,086 7,078	0.9%	$ 7,186	$ 8,950 7,171	-0.2%	$ 7,294 20,105	$ 25,804 7,388	1.3%	8,939 $ 7,404	$ 30,453 7,605	2.7%	6,981 $ 7,515	14,626 $ 7,883	4.9%	12,437 $ 9,275	10,037 $ 9,530	14,409 $ 9,792	9,965 10,061	10,632 $ 10,338

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,

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

Fixed Asset Continuity Schedule

Year **2020** **MIFRS**

			Cost				Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**	
	1608	Franchises & Consents	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
	1609	Capital Contributions Paid	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
1	1610	Miscellaneous Intangible Plant	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
12	1611	Computer Software (Formally known as Account 1925) - 5 yr	$ 977,931	$ -	$ -	977,931	-$ 933,020	-$ 10,724	$ -	-943,744	34,187	$ 44,911
12	1611A	Computer Software (Formally known as Account 1925) - 10 yr	$ 2,122,933	$ -	$ -	2,122,933	-$ 1,305,292	-$ 212,658	$ -	-1,517,950	604,983	$ 817,641
47	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 21,220,182	$ 107,272	$ -	21,327,454	-$ 6,205,496	-$ 541,657	$ -	-6,747,152	14,580,302	$ 15,014,687
N/A	1805	Land	$ 710,903	$ -	$ -	710,903	$ -	$ -	$ -	0	710,903	$ 710,903
47	1808	Buildings - Fixtures	$ 2,143,803	$ -	$ -	2,143,803	-$ 280,895	-$ 42,124	$ -	-323,019	1,820,784	$ 1,862,908
47	1808A	Buildings - Components	$ 623,263	$ 129,184	$ -	752,447	-$ 85,345	-$ 29,393	$ -	-114,738	637,709	$ 537,918
13	1810	Leasehold Improvements	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
47	1820	Distribution Station Equipment <50 kV - Stations	$ 13,231,270	$ 68,058	-$ 846,310	12,453,018	-$ 5,500,729	-$ 212,413	$ 793,088	-4,920,054	7,532,964	$ 7,730,541
47	1820A	Distribution Station Equipment <50 kV - Switches/Breakers	$ 2,278,832	$ 0	-$ 13,148	2,265,684	-$ 743,756	-$ 52,505	$ 13,148	-783,113	1,482,571	$ 1,535,076
47	1825	Storage Battery Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
47	1830	Poles, Towers & Fixtures	$ 66,804,923	$ 2,424,094	-$ 78,309	69,150,708	-$ 27,149,566	-$ 929,953	$ 77,495	-28,002,024	41,148,684	$ 39,655,358
47	1835	Overhead Conductors & Devices	$ 43,573,523	$ 2,698,680	$ -	46,272,203	-$ 13,275,900	-$ 881,039	$ -	-14,156,938	32,115,265	$ 30,297,624
47	1840	Underground Conduit	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
47	1845	Underground Conductors & Devices	$ 1,929,529	$ 31,856	$ -	1,961,385	-$ 587,709	-$ 43,921	$ -	-631,630	1,329,755	$ 1,341,820
47	1850	Line Transformers	$ 13,180,779	$ 608,135	-$ 57,934	13,730,980	-$ 6,882,191	-$ 342,179	$ 33,493	-7,190,878	6,540,102	$ 6,298,588
47	1855	Services (Overhead & Underground)	$ 3,361,906	$ -	$ -	3,361,906	-$ 2,379,080	-$ 41,000	$ -	-2,420,080	941,826	$ 982,826
47	1860	Meters	$ 908,352	-$ 0	-$ 34,061	874,291	-$ 610,097	-$ 20,108	$ 19,647	-610,558	263,733	$ 298,255
47	1860A	Meters (Smart Meters)	$ 3,968,716	$ 218,370	-$ 15,673	4,171,413	-$ 2,299,671	-$ 273,722	$ 10,028	-2,563,365	1,608,048	$ 1,669,045
47	1860B	Meters - PT's and CT's	$ 252,375	$ 83,742	$ -	336,116	-$ 106,451	-$ 47,707	$ -	-154,157	181,959	$ 145,924
47	1865	Other Installations on Customer's Premises	$ 194,063	$ -	$ -	194,063	-$ 188,275	-$ 4,653	$ -	-192,928	1,135	$ 5,788
47	1875	Street Lighting and Signal Systems	$ 16,523	$ -	$ -	16,523	-$ 16,523	$ -	$ -	-16,523	0	$ -
N/A	1905	Land	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
1	1908	Buildings & Fixtures	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
1	1908A	Buildings & Fixtures	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
12	1910	Leasehold Improvements	$ 80,040	$ 3,344	$ -	83,384	-$ 75,906	-$ 1,493	$ -	-77,399	5,985	$ 4,134
8	1915	Office Furniture & Equipment (10 years)	$ 366,233	$ 3,000	$ -	369,233	-$ 292,597	-$ 14,344	$ -	-306,941	62,292	$ 73,636
8	1915A	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
50	1920	Computer Equipment - Hardware	$ 925,572	$ 61,070	$ -	986,641	-$ 653,205	-$ 97,108	$ -	-750,313	236,328	$ 272,367
45	1920A	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
50	1920B	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
10	1930	Transportation Equipment - 5 Yr	$ 1,401,279	$ 200,057	-$ 354,718	1,246,618	-$ 1,161,483	-$ 100,069	$ 354,718	-906,834	339,784	$ 239,796
10	1930A	Transportation Equipment - 10 Yr	$ 4,726,983	$ 584,767	-$ 1,193,337	4,118,413	-$ 3,038,897	-$ 322,241	$ 1,161,414	-2,199,725	1,918,689	$ 1,688,086
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,958,082	$ 26,539	-$ 10,114	1,974,507	-$ 1,634,528	-$ 67,792	$ 2,715	-1,699,605	274,902	$ 323,554
10	1945	Measurement & Testing Equipment	$ 242,447	$ -	$ -	242,447	-$ 184,694	-$ 13,303	$ -	-197,997	44,450	$ 57,753
10	1950	Power Operated Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
10	1955	Communications Equipment - 10 yr	$ 483,650	$ -	$ -	483,650	-$ 317,168	-$ 48,365	$ -	-365,533	118,117	$ 166,482
10	1955A	Communications Equipment - 5 yr	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
8	1955B	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
8	1960	Miscellaneous Equipment - 10 yr	$ 92,536	$ 5,946	$ -	98,482	-$ 62,451	-$ 4,114	$ -	-66,565	31,917	$ 30,085
8	1960A	Miscellaneous Equipment - 5 yr	$ 492,118	$ -	$ -	492,118	-$ 479,842	-$ 5,275	$ -	-485,117	7,001	$ 12,276
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
8	1980	System Supervisor Equipment	$ 146,422	$ -	$ -	146,422	-$ 27,307	-$ 7,328	$ -	-34,635	111,787	$ 119,115
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0	$ -
47	1995	Contributions & Grants	-$ 821,734	-$ 168,464	$ -	-990,198	$ 145,330	$ 20,630	$ -	165,960	-824,238	-$ 676,404
		Sub-Total	**187,593,436**	**7,085,650**	**-2,603,604**	**192,075,482**	**-76,332,744**	**-4,346,559**	**2,465,745**	**-78,213,558**	**113,861,924**	
		Less Socialized Renewable Energy Generation Investments (input as negative)										
		Less Other Non Rate-Regulated Utility Assets (input as negative)										
		Total PP&E for Rate Base Purposes	**$ 187,593,436**	**$ 7,085,650**	**-$ 2,603,604**	**$ 192,075,482**	**-$ 76,332,744**	**-$ 4,346,559**	**$ 2,465,745**	**-$ 78,213,558**	**$ 113,861,924**	
	2055	**Add: Construction Work in Progress - Electric**	$ 5,620,404	$ 394,948	$ -	6,015,352	$ -	$ -	$ -	0	6,015,352	
		Total PP&E	**193,213,840**	**7,480,598**	**-2,603,604**	**198,090,834**	**-76,332,744**	**-4,346,559**	**2,465,745**	**-78,213,558**	**119,877,276**	
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						**0**				
		Total						**-4,346,559**			$ -	

Less: Fully Allocated Depreciation	
Transportation	-$ 422,310
Stores Equipment	
Deferred Revenue	
Net Depreciation	-3,924,249

Year 2021 **MIFRS**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
	1608	Franchises & Consents	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
	1609	Capital Contributions Paid	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
1	1610	Miscellaneous Intangible Plant	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
12	1611	Computer Software (Formally known as Account 1925) - 5 yr	$ 977,931	$ 33,184	$ -	1,011,114	-$ 943,744	-$ 11,414	$ -	-955,157	55,957
47	1611A	Computer Software (Formally known as Account 1925) - 10 yr	$ 2,122,933	$ 15,575	$ -	2,138,509	-$ 1,517,950	-$ 206,689	$ -	-1,724,640	413,869
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 21,327,454	$ 156,562	$ -	21,484,017	-$ 6,747,152	-$ 544,821	$ -	-7,291,974	14,192,043
N/A	1805	Land	$ 710,903	$ -	$ -	710,903	$ -	$ -	$ -	0	710,903
47	1808	Buildings - Fixtures	$ 2,143,803	$ 0	$ -	2,143,803	-$ 323,019	-$ 42,124	$ -	-365,143	1,778,660
47	1808A	Buildings - Components	$ 752,447	$ 14,019	$ -	766,467	-$ 114,738	-$ 29,955	$ -	-144,694	621,773
13	1810	Leasehold Improvements	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1820	Distribution Station Equipment <50 kV - Stations	$ 12,453,018	$ 903,473	-$ 312,546	13,043,945	-$ 4,920,054	-$ 200,997	$ 36,928	-5,084,123	7,959,822
47	1820A	Distribution Station Equipment <50 kV - Switches/Breakers	$ 2,265,684	$ 32,138	-$ 19,569	2,278,252	-$ 783,113	-$ 52,461	$ 2,841	-832,733	1,445,520
47	1825	Storage Battery Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1830	Poles, Towers & Fixtures	$ 69,150,708	$ 3,979,849	-$ 108,115	73,022,442	-$ 28,002,024	-$ 1,209,169	$ 89,878	-29,121,315	43,901,126
47	1835	Overhead Conductors & Devices	$ 46,272,203	$ 2,608,425	-$ 9,747	48,870,882	-$ 14,156,938	-$ 878,689	$ 9,747	-15,025,881	33,845,001
47	1840	Underground Conduit	$ -	$ 33,543	$ -	33,543	$ -	-$ 56	$ -	-56	33,487
47	1845	Underground Conductors & Devices	$ 1,961,385	$ 188,286	$ -	2,149,671	-$ 631,630	-$ 44,582	$ -	-676,212	1,473,459
47	1850	Line Transformers	$ 13,730,980	$ 703,092	$ -	14,434,072	-$ 7,190,878	-$ 241,998	$ -	-7,432,875	7,001,197
47	1855	Services (Overhead & Underground)	$ 3,361,906	$ -	$ -	3,361,906	-$ 2,420,080	-$ 41,018	$ -	-2,461,098	900,808
47	1860	Meters	$ 874,291	-$ 215,167	$ -	659,124	-$ 610,558	$ 57,316	$ -	-553,242	105,882
47	1860A	Meters (Smart Meters)	$ 4,171,413	$ 282,198	$ -	4,453,612	-$ 2,563,365	-$ 371,624	$ -	-2,934,990	1,518,622
47	1860B	Meters - PT's and CT's	$ 336,116	$ 22,819	$ -	358,935	-$ 154,157	-$ 10,665	$ -	-164,822	194,113
47	1865	Other Installations on Customer's Premises	$ 194,063	$ -	$ -	194,063	-$ 192,928	-$ 1,135	$ -	-194,063	0
47	1875	Street Lighting and Signal Systems	$ 16,523	$ -	$ -	16,523	-$ 16,523	$ -	$ -	-16,523	0
N/A	1905	Land	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
1	1908	Buildings & Fixtures	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
1	1908A	Buildings & Fixtures-25Yrs	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
12	1910	Leasehold Improvements	$ 83,384	$ 17,981	$ -	101,365	-$ 77,399	-$ 3,296	$ -	-80,695	20,670
8	1915	Office Furniture & Equipment (10 years)	$ 369,233	$ 17,267	$ -	386,500	-$ 306,941	-$ 14,779	$ -	-321,720	64,780
8	1915A	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
50	1920	Computer Equipment - Hardware	$ 986,641	$ 45,400	-$ 167	1,031,874	-$ 750,313	-$ 80,614	$ 167	-830,760	201,114
45	1920A	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
50	1920B	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
10	1930	Transportation Equipment - 5 Yr	$ 1,246,618	$ 49,942	$ -	1,296,561	-$ 906,834	-$ 113,880	$ -	-1,020,715	275,846
10	1930A	Transportation Equipment - 10 Yr	$ 4,118,413	$ 449,571	-$ 503,192	4,064,791	-$ 2,199,725	-$ 356,799	$ 503,192	-2,053,331	2,011,460
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1940	Tools, Shop & Garage Equipment	$ 1,974,507	$ 59,097	-$ 40,233	1,993,371	-$ 1,699,605	-$ 65,707	$ 39,947	-1,725,365	268,006
10	1945	Measurement & Testing Equipment	$ 242,447	$ 18,742	$ -	261,189	-$ 197,997	-$ 14,783	$ -	-212,780	48,409
10	1950	Power Operated Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
10	1955	Communications Equipment - 10 yr	$ 483,650	$ 3,980	$ -	487,630	-$ 365,533	-$ 48,605	$ -	-414,138	73,492
10	1955A	Communications Equipment - 5 yr	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1955B	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ 98,482	$ 5,417	$ -	103,899	-$ 66,565	-$ 4,716	$ -	-71,281	32,618
8	1960A	Miscellaneous Equipment - 5 yr	$ 492,118	$ -	$ -	492,118	-$ 485,117	-$ 4,986	$ -	-490,103	2,015
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1980	System Supervisor Equipment	$ 146,422	$ -	$ -	146,422	-$ 34,635	-$ 7,327	$ -	-41,962	104,460
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1990	Other Tangible Property	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1995	Contributions & Grants	-$ 990,198	-$ 472,311	$ 96	-1,462,413	$ 165,960	$ 25,423	-$ 18	191,365	-1,271,048
		Sub-Total	**192,075,482**	**8,953,081**	**-993,473**	**200,035,090**	**-78,213,558**	**-4,520,151**	**682,682**	**-82,051,027**	**117,984,063**
		Less Socialized Renewable Energy Generation Investments (input as negative)									
		Less Other Non Rate-Regulated Utility Assets (input as negative)									
		Total PP&E for Rate Base Purposes	**$ 192,075,482**	**$ 8,953,081**	**-$ 993,473**	**$ 200,035,090**	**-$ 78,213,558**	**-$ 4,520,151**	**$ 682,682**	**-$ 82,051,027**	**$ 117,984,063**
	2055	**Add: Construction Work in Progress - Electric**	6,015,352	11,302,346	0	17,317,698	0	0	0	0	17,317,698
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**198,090,834**	**20,255,427**	**-993,473**	**217,352,787**	**-78,213,558**	**-4,520,151**	**682,682**	**-82,051,027**	**135,301,761**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**-4,520,151**			$ -

Less: Fully Allocated Depreciation	
Transportation	-$ 470,680
Stores Equipment	
Deferred Revenue	
Net Depreciation	-4,049,472

		Year	2022	MIFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
	1608	Franchises & Consents	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
	1609	Capital Contributions Paid	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
1	1610	Miscellaneous Intangible Plant	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
12	1611	Computer Software (Formally known as Account 1925) - 5 yr	$ 1,011,114	$ 6,254	-$ 103,311	914,058	-$ 955,157	-$ 17,511	$ 103,311	-869,358	44,700
12	1611A	Computer Software (Formally known as Account 1925) - 10 yr	$ 2,138,509	$ 9,179	$ -	2,147,688	-$ 1,724,640	-$ 120,667	$ -	-1,845,307	302,381
47	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 21,484,017	$ 178,426	$ -	21,662,443	-$ 7,291,974	-$ 548,619	$ -	-7,840,593	13,821,850
N/A	1805	Land	$ 710,903	$ -	$ -	710,903	$ -	$ -	$ -	0	710,903
47	1808	Buildings - Fixtures	$ 2,143,803	-$ 0	$ -	2,143,803	-$ 365,143	-$ 42,123	$ -	-407,266	1,736,537
47	1808A	Buildings - Components	$ 766,467	$ 165,728	$ -	932,194	-$ 144,694	-$ 33,822	$ -	-178,515	753,679
13	1810	Leasehold Improvements	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1820	Distribution Station Equipment <50 kV - Stations	$ 13,043,945	$ 2,707,920	-$ 22,975	15,728,890	-$ 5,084,123	-$ 244,567	$ 31,190	-5,297,500	10,431,390
47	1820A	Distribution Station Equipment <50 kV - Switches/Breakers	$ 2,278,252	$ 114,678	-$ 109,348	2,283,582	-$ 832,733	-$ 55,685	$ 66,775	-821,642	1,461,940
47	1825	Storage Battery Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1830	Poles, Towers & Fixtures	$ 73,022,442	$ 3,500,020	-$ 959,777	75,562,684	-$ 29,121,315	-$ 1,290,543	$ 1,132,911	-29,278,947	46,283,737
47	1835	Overhead Conductors & Devices	$ 48,870,882	$ 2,045,978	$ -	50,916,860	-$ 15,025,881	-$ 933,834	-$ 14,654	-15,974,369	34,942,491
47	1840	Underground Conduit	$ 33,543	$ -	$ -	33,543	-$ 56	-$ 671	$ -	-727	32,816
47	1845	Underground Conductors & Devices	$ 2,149,671	$ 58,143	-$ 234	2,207,579	-$ 676,212	-$ 49,016	$ 178	-725,049	1,482,530
47	1850	Line Transformers	$ 14,434,072	$ 965,020	-$ 102,867	15,296,225	-$ 7,432,875	-$ 262,061	-$ 90,127	-7,785,064	7,511,161
47	1855	Services (Overhead & Underground)	$ 3,361,906	$ -	$ -	3,361,906	-$ 2,461,098	-$ 40,999	$ -	-2,502,097	859,809
47	1860	Meters	$ 659,124	$ 29,029	$ -	688,153	-$ 553,242	-$ 12,899	-$ 20,860	-587,001	101,152
47	1860A	Meters (Smart Meters)	$ 4,453,612	$ 93,924	-$ 21,627	4,525,909	-$ 2,934,990	-$ 314,206	$ 7,902	-3,241,294	1,284,615
47	1860B	Meters - PT's and CT's	$ 358,935	$ 51,481	$ -	410,416	-$ 164,822	-$ 11,503	$ -	-176,325	234,091
47	1865	Other Installations on Customer's Premises	$ 194,063	$ -	$ -	194,063	-$ 194,063	$ -	$ -	-194,063	0
47	1875	Street Lighting and Signal Systems	$ 16,523	$ -	-$ 16,523	0	-$ 16,523	$ -	$ 16,523	0	0
N/A	1905	Land	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
1	1908	Buildings & Fixtures	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
1	1908A	Buildings & Fixtures-25Yrs	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
12	1910	Leasehold Improvements	$ 101,365	$ -	$ -	101,365	-$ 80,695	-$ 5,201	$ -	-85,896	15,469
8	1915	Office Furniture & Equipment (10 years)	$ 386,500	$ 1,194	-$ 39,037	348,657	-$ 321,720	-$ 14,891	$ 39,037	-297,574	51,083
8	1915A	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
50	1920	Computer Equipment - Hardware	$ 1,031,874	$ 129,326	-$ 153,728	1,007,472	-$ 830,760	-$ 91,430	$ 153,728	-768,462	239,010
45	1920A	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
50	1920B	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
10	1930	Transportation Equipment - 5 Yr	$ 1,296,561	$ 47,376	-$ 96,772	1,247,164	-$ 1,020,715	-$ 98,016	$ 96,772	-1,021,958	225,206
10	1930A	Transportation Equipment - 10 Yr	$ 4,064,791	$ 91,506	$ -	4,156,298	-$ 2,053,331	-$ 355,148	$ -	-2,408,480	1,747,818
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1940	Tools, Shop & Garage Equipment	$ 1,993,371	$ 48,452	-$ 119,206	1,922,617	-$ 1,725,365	-$ 58,682	$ 118,100	-1,665,947	256,670
10	1945	Measurement & Testing Equipment	$ 261,189	$ -	$ -	261,189	-$ 212,780	-$ 15,174	$ -	-227,954	33,235
10	1950	Power Operated Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
10	1955	Communications Equipment - 10 yr	$ 487,630	$ -	$ -	487,630	-$ 414,138	-$ 46,555	$ -	-460,693	26,937
10	1955A	Communications Equipment - 5 yr	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1955B	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ 103,899	$ 0	$ -	103,899	-$ 71,281	-$ 5,086	$ -	-76,367	27,532
8	1960A	Miscellaneous Equipment - 5 yr	$ 492,118	$ 9,900	-$ 465,748	36,271	-$ 490,103	-$ 1,971	$ 465,748	-26,327	9,944
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1980	System Supervisor Equipment	$ 146,422	$ -	$ -	146,422	-$ 41,962	-$ 7,328	$ -	-49,290	97,132
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1990	Other Tangible Property	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1995	Contributions & Grants	-$ 1,462,413	-$ 263,696	$ -	-1,726,108	$ 191,365	$ 36,585	$ -	227,949	-1,498,159
		Sub-Total	**200,035,090**	**9,989,839**	**-2,211,153**	**207,813,776**	**-82,051,027**	**-4,641,623**	**2,106,534**	**-84,586,116**	**123,227,660**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E for Rate Base Purposes	**$ 200,035,090**	**$ 9,989,839**	**-$ 2,211,153**	**$ 207,813,776**	**-$ 82,051,027**	**-$ 4,641,623**	**$ 2,106,534**	**-$ 84,586,116**	**$ 123,227,660**
	2055	**Add: Construction Work in Progress - Electric**	$ 17,317,698	-$ 4,462,538	$ -	12,855,159	$ -	$ -	$ -	0	12,855,159
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**217,352,787**	**5,527,300**	**-2,211,153**	**220,668,935**	**-82,051,027**	**-4,641,623**	**2,106,534**	**-84,586,116**	**136,082,819**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**-4,641,623**			$ -

Less: Fully Allocated Depreciation	
Transportation	-$ 453,164
Stores Equipment	
Deferred Revenue	
Net Depreciation	-4,188,459

Year 2023 **MIFRS**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
	1608	Franchises & Consents	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
	1609	Capital Contributions Paid	$ -	$ 44,289	$ -	44,289	$ -	-$ 2,214	$ -	-2,214	42,075
1	1610	Miscellaneous Intangible Plant	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
12	1611	Computer Software (Formally known as Account 1925) - 5 yr	$ 914,058	$ 12,517	$ -	926,574	-$ 869,358	-$ 17,847	$ -	-887,204	39,370
12	1611A	Computer Software (Formally known as Account 1925) - 10 yr	$ 2,147,688	$ -	$ -	2,147,688	-$ 1,845,307	-$ 75,072	$ -	-1,920,379	227,309
47	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 21,662,443	$ 464,942	$ -	22,127,385	-$ 7,840,593	-$ 553,827	$ -	-8,394,420	13,732,965
N/A	1805	Land	$ 710,903	$ -	$ -	710,903	$ -	$ -	$ -	0	710,903
47	1808	Buildings - Fixtures	$ 2,143,803	$ -	$ -	2,143,803	-$ 407,266	-$ 42,124	$ -	-449,390	1,694,413
47	1808A	Buildings - Components	$ 932,194	$ 21,081	$ -	953,275	-$ 178,515	-$ 37,358	$ -	-215,873	737,402
13	1810	Leasehold Improvements	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1820	Distribution Station Equipment <50 kV - Stations	$ 15,728,890	$ 26,165	$ -	15,755,055	-$ 5,297,500	-$ 266,595	$ -	-5,564,095	10,190,960
47	1820A	Distribution Station Equipment <50 kV - Switches/Breakers	$ 2,283,582	$ 12,502	$ -	2,296,084	-$ 821,642	-$ 53,564	$ -	-875,206	1,420,878
47	1825	Storage Battery Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1830	Poles, Towers & Fixtures	$ 75,562,684	$ 12,074,350	-$ 88,183	87,548,852	-$ 29,278,947	-$ 1,380,432	$ 66,712	-30,592,667	56,956,185
47	1835	Overhead Conductors & Devices	$ 50,916,860	$ 3,905,610	$ -	54,822,470	-$ 15,974,369	-$ 986,293	$ -	-16,960,662	37,861,808
47	1840	Underground Conduit	$ 33,543	$ -	$ -	33,543	-$ 727	-$ 671	$ -	-1,398	32,145
47	1845	Underground Conductors & Devices	$ 2,207,579	$ 11,399	$ -	2,218,978	-$ 725,049	-$ 50,626	$ -	-775,675	1,443,303
47	1850	Line Transformers	$ 15,296,225	$ 1,011,761	-$ 84,026	16,223,960	-$ 7,785,064	-$ 282,380	$ 63,738	-8,003,706	8,220,254
47	1855	Services (Overhead & Underground)	$ 3,361,906	$ -	$ -	3,361,906	-$ 2,502,097	-$ 41,020	$ -	-2,543,117	818,789
47	1860	Meters	$ 688,153	$ 0	$ -	688,153	-$ 587,001	-$ 13,815	$ -	-600,816	87,337
47	1860A	Meters (Smart Meters)	$ 4,525,909	$ 115,147	-$ 8,169	4,632,888	-$ 3,241,294	-$ 318,370	$ 6,144	-3,553,520	1,079,368
47	1860B	Meters - PT's and CT's	$ 410,416	$ 102,168	$ -	512,584	-$ 176,325	-$ 12,789	$ -	-189,114	323,470
47	1865	Other Installations on Customer's Premises	$ 194,063	$ -	$ -	194,063	-$ 194,063	$ -	$ -	-194,063	0
N/A	1905	Land	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
1	1908	Buildings & Fixtures	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
1	1908A	Buildings & Fixtures-25Yrs	$ -	$ -	$ -	0	$ -	$ 0	$ -	0	0
12	1910	Leasehold Improvements	$ 101,365	$ -	$ -	101,365	-$ 85,896	-$ 5,200	$ -	-91,096	10,269
8	1915	Office Furniture & Equipment (10 years)	$ 348,657	$ 35,792	$ -	384,449	-$ 297,574	-$ 9,782	$ -	-307,356	77,093
8	1915A	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
50	1920	Computer Equipment - Hardware	$ 1,007,472	$ 119,033	$ -	1,126,504	-$ 768,462	-$ 99,762	$ -	-868,223	258,281
45	1920A	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
50	1920B	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
10	1930	Transportation Equipment - 5 Yr	$ 1,247,164	$ 403,244	-$ 286,375	1,364,034	-$ 1,021,958	-$ 128,446	$ 286,375	-864,030	500,004
10	1930A	Transportation Equipment - 10 Yr	$ 4,156,298	$ 742,074	-$ 2,827	4,895,545	-$ 2,408,480	-$ 370,671	$ 2,827	-2,776,324	2,119,221
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1940	Tools, Shop & Garage Equipment	$ 1,922,617	$ 65,875	-$ 3,988	1,984,505	-$ 1,665,947	-$ 53,963	$ 2,534	-1,717,376	267,129
10	1945	Measurement & Testing Equipment	$ 261,189	$ 12,472	$ -	273,661	-$ 227,954	-$ 8,376	$ -	-236,330	37,331
10	1950	Power Operated Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
10	1955	Communications Equipment - 10 yr	$ 487,630	$ -	$ -	487,630	-$ 460,693	-$ 10,643	$ -	-471,336	16,294
10	1955A	Communications Equipment - 5 yr	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1955B	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ 103,899	$ -	$ -	103,899	-$ 76,367	-$ 5,086	$ -	-81,453	22,446
8	1960A	Miscellaneous Equipment - 5 yr	$ 36,271	$ 13,136	$ -	49,406	-$ 26,327	-$ 4,249	$ -	-30,575	18,831
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1980	System Supervisor Equipment	$ 146,422	$ 39,067	$ -	185,489	-$ 49,290	-$ 7,475	$ -	-56,765	128,724
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1990	Other Tangible Property	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1995	Contributions & Grants	-$ 1,726,108	-$ 271,850	$ 908	-1,997,050	$ 227,949	$ 41,808	-$ 58	269,699	-1,727,351
		Sub-Total	**207,813,776**	**18,960,773**	**-472,660**	**226,301,889**	**-84,586,116**	**-4,796,840**	**428,273**	**-88,954,683**	**137,347,206**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E for Rate Base Purposes	**$ 207,813,776**	**$ 18,960,773**	**-$ 472,660**	**$ 226,301,889**	**-$ 84,586,116**	**-$ 4,796,840**	**$ 428,273**	**-$ 88,954,683**	**$ 137,347,206**
	2055	**Add: Construction Work in Progress - Electric**	$ 12,855,159	-$ 7,763,839	$ -	5,091,320	$ -	$ -	$ -	0	5,091,320
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**220,668,935**	**11,196,933**	**-472,660**	**231,393,208**	**-84,586,116**	**-4,796,840**	**428,273**	**-88,954,683**	**142,438,526**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**-4,796,840**			$ -

Less: Fully Allocated Depreciation	
Transportation	-$ 499,117
Stores Equipment	
Deferred Revenue	
Net Depreciation	-4,297,723

Year 2024 MIFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	ACM Cost	ACM Accumulated Depreciation	Adjusted 2025 Opening Cost	Adjusted 2025 Opening A/D	Adjusted NBV
	1608	Franchises & Consents	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
47	1609	Capital Contributions Paid	$ 44,289	$ -		44,289	-$ 2,214	-$ 4,429		-6,643	37,646			$ 44,289	-$ 6,643	$ 37,646
	1609A	Capital Contributions Paid - 45 Yr		$ -		0	$ -	$ 1,714		1,714	1,714	$ 11,006,211	-$ 343,349	$ 11,006,211	-$ 341,635	$ 10,664,576
1	1610	Miscellaneous Intangible Plant	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925) - 5 yr	$ 926,574	$ -		926,574	-$ 887,204	-$ 15,377		-902,581	23,993			$ 926,574	-$ 902,581	$ 23,993
12	1611A	Computer Software (Formally known as Account 1925) - 10 yr	$ 2,147,688	$ 122,074		2,269,762	-$ 1,920,379	-$ 74,454		-1,994,832	274,930			$ 2,269,762	-$ 1,994,832	$ 274,930
47	1612	Land Rights (Formally known as Account 1906 and 1806) - 40 Years	$ 22,127,385	$ 1,399,711		23,527,096	-$ 8,394,420	-$ 583,356		-8,977,776	14,549,320	$ 713	-$ 38	$ 23,527,809	-$ 8,977,814	$ 14,549,995
47	1612A	Land Rights (Formally known as Account 1906 and 1806) - 10 Years	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
N/A	1805	Land	$ 710,903	$ -		710,903	$ -	$ -		0	710,903	$ 1,065,963	$ -	$ 1,776,866	$ -	$ 1,776,866
47	1808	Buildings - Fixtures	$ 2,143,803	$ -		2,143,803	-$ 449,390	-$ 42,124		-491,514	1,652,289			$ 2,143,803	-$ 491,514	$ 1,652,289
47	1808A	Buildings - Components	$ 953,275	$ 97,171		1,050,447	-$ 215,873	-$ 38,940		-254,813	795,633			$ 1,050,447	-$ 254,813	$ 795,633
13	1810	Leasehold Improvements	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV - Stations	$ 15,755,055	$ 4,821,386		20,576,441	-$ 5,564,095	-$ 331,288		-5,895,383	14,681,058			$ 20,576,441	-$ 5,895,383	$ 14,681,058
47	1820A	Distribution Station Equipment <50 kV - Switches/Breakers	$ 2,296,084	$ 199,864		2,495,949	-$ 875,206	-$ 56,016		-931,223	1,564,726			$ 2,495,949	-$ 931,223	$ 1,564,726
47	1825	Storage Battery Equipment	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 87,548,852	$ 6,422,057		93,970,909	-$ 30,592,667	-$ 1,744,364		-32,337,031	61,633,878			$ 93,970,909	-$ 32,337,031	$ 61,633,878
47	1835	Overhead Conductors & Devices	$ 54,822,470	$ 4,218,115		59,040,585	-$ 16,960,662	-$ 1,121,580		-18,082,242	40,958,343			$ 59,040,585	-$ 18,082,242	$ 40,958,343
47	1840	Underground Conduit	$ 33,543	$ -		33,543	-$ 1,398	-$ 671		-2,069	31,474			$ 33,543	-$ 2,069	$ 31,474
47	1845	Underground Conductors & Devices	$ 2,218,978	$ 214,149		2,433,127	-$ 775,675	-$ 53,309		-828,984	1,604,143			$ 2,433,127	-$ 828,984	$ 1,604,143
47	1850	Line Transformers	$ 16,223,960	$ 741,793		16,965,753	-$ 8,003,706	-$ 311,831		-8,315,537	8,650,216			$ 16,965,753	-$ 8,315,537	$ 8,650,216
47	1855	Services (Overhead & Underground)	$ 3,361,906	$ -		3,361,906	-$ 2,543,117	-$ 41,002		-2,584,119	777,787			$ 3,361,906	-$ 2,584,119	$ 777,787
47	1860	Meters	$ 688,153	$ -		688,153	-$ 600,816	-$ 13,816		-614,632	73,521			$ 688,153	-$ 614,632	$ 73,521
47	1860A	Meters (Smart Meters)	$ 4,632,888	$ 119,657		4,752,545	-$ 3,553,520	-$ 278,105		-3,831,624	920,921			$ 4,752,545	-$ 3,831,624	$ 920,921
47	1860B	Meters - PT's and CT's	$ 512,584	$ 13,295		525,879	-$ 189,114	-$ 16,419		-205,533	320,347			$ 525,879	-$ 205,533	$ 320,347
47	1865	Other Installations on Customer's Premises	$ 194,063	$ -		194,063	-$ 194,063	$ -		-194,063	0			$ 194,063	-$ 194,063	$ -
N/A	1905	Land	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
1	1908	Buildings & Fixtures	$ -	$ -		0	$ -	$ 0		0	0	$ 15,237,022	-$ 623,075	$ 15,237,022	-$ 623,075	$ 14,613,947
1	1908A	Buildings & Fixtures-25Yrs	$ -	$ 36,976		36,976	$ 0	-$ 1,170		-1,170	35,806	$ 10,745	-$ 430	$ 47,721	-$ 1,600	$ 46,121
12	1910	Leasehold Improvements	$ 101,365	$ -		101,365	-$ 91,096	-$ 4,655		-95,751	5,614			$ 101,365	-$ 95,751	$ 5,614
8	1915	Office Furniture & Equipment (10 years)	$ 384,449	$ 20,000		404,449	-$ 307,356	-$ 13,443		-320,799	83,650	$ 8,991	-$ 1,873	$ 413,440	-$ 322,672	$ 90,768
8	1915A	Office Furniture & Equipment (5 years)	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 1,126,504	$ 51,467		1,177,971	-$ 868,223	-$ 92,642		-960,865	217,106	$ 220,574	-$ 91,905	$ 1,398,545	-$ 1,052,770	$ 345,775
45	1920A	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
50	1920B	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
10	1930	Transportation Equipment - 5 Yr	$ 1,364,034	$ 584,674		1,948,707	-$ 864,030	-$ 211,687		-1,075,717	872,990			$ 1,948,707	-$ 1,075,717	$ 872,990
10	1930A	Transportation Equipment - 10 Yr	$ 4,895,545	$ -		4,895,545	-$ 2,776,324	-$ 391,625		-3,167,949	1,727,596			$ 4,895,545	-$ 3,167,949	$ 1,727,596
10	1935	Stores Equipment	$ -	$ -		0	$ -	$ -		0	0	$ 55,244	-$ 10,129	$ 55,244	-$ 10,129	$ 45,115
8	1940	Tools, Shop & Garage Equipment	$ 1,984,505	$ 90,000		2,074,505	-$ 1,717,376	-$ 52,914		-1,770,290	304,215			$ 2,074,505	-$ 1,770,290	$ 304,215
10	1945	Measurement & Testing Equipment	$ 273,661	$ -		273,661	-$ 236,330	-$ 6,520		-242,850	30,811			$ 273,661	-$ 242,850	$ 30,811
10	1950	Power Operated Equipment	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
10	1955	Communications Equipment - 10 yr	$ 487,630	$ 119,395		607,024	-$ 471,336	-$ 11,283		-482,618	124,406			$ 607,024	-$ 482,618	$ 124,406
10	1955A	Communications Equipment - 5 yr	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
8	1955B	Communication Equipment (Smart Meters)	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
8	1960	Miscellaneous Equipment - 10 yr	$ 103,899	$ -		103,899	-$ 81,453	-$ 4,980		-86,433	17,466	$ 55,411	-$ 7,852	$ 159,310	-$ 94,285	$ 65,025
8	1960A	Miscellaneous Equipment - 5 yr	$ 49,406	$ -		49,406	-$ 30,575	-$ 4,607		-35,182	14,224			$ 49,406	-$ 35,182	$ 14,224
47	1970	Load Management Controls Customer Premises	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
8	1980	System Supervisor Equipment	$ 185,489	$ 251,000		436,489	-$ 56,765	-$ 21,874		-78,639	357,850			$ 436,489	-$ 78,639	$ 357,850
47	1985	Miscellaneous Fixed Assets	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -		0	$ -	$ -		0	0			$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 1,997,050	-$ 5,252,085		-7,249,135	$ 269,699	$ 102,536		372,236	-6,876,900			-$ 7,249,135	$ 372,236	-$ 6,876,900
		Sub-Total	**$ 226,301,889**	**$ 14,270,698**	**$ -**	**$ 240,572,587**	**-$ 88,954,683**	**-$ 5,440,229**	**$ -**	**-$ 94,394,912**	**$ 146,177,675**	**$ 27,660,874**	**-$ 1,078,651**	**$ 268,233,461**	**-$ 95,473,562**	**$ 172,759,898**
		Less Socialized Renewable Energy Generation Investments (input as negative)														
		Less Other Non Rate-Regulated Utility Assets (input as negative)														
		Total PP&E for Rate Base Purposes	**$ 226,301,889**	**$ 14,270,698**	**$ -**	**$ 240,572,587**	**-$ 88,954,683**	**-$ 5,440,229**	**$ -**	**-$ 94,394,912**	**$ 146,177,675**	**$ 27,660,874**	**-$ 1,078,651**	**$ 268,233,461**	**-$ 95,473,562**	**$ 172,759,898**
	2055	**Add: Construction Work in Progress - Electric**	$ 5,091,320	-$ 6,231,000	$ -	-1,139,680	$ -	$ -	$ -	0	-1,539,680			-$ 1,139,680	$ -	-$ 1,139,680
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0					
		Total PP&E	**$ 231,393,208**	**$ 8,039,698**	**$ -**	**$ 239,432,907**	**-$ 88,954,683**	**-$ 5,440,229**	**$ -**	**-$ 94,394,912**	**$ 144,637,995**	**$ 27,660,874**	**-$ 1,078,651**	**$ 267,093,780**	**-$ 95,473,562**	**$ 171,620,218**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)														
		Total						-5,440,229			$ -					

Less: Fully Allocated Depreciation	
Transportation	-$ 603,312
Stores Equipment	
Deferred Revenue	
Net Depreciation	-4,836,916

Year 2025 **MIFRS**

			Cost				**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
	1608	Franchises & Consents	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
	1609	Capital Contributions Paid	$ 44,289	$ -	$ -	44,289	-$ 6,643	-$ 4,429	$ -	-11,072	33,217
	1609A	Capital Contributions Paid - 45 Yr	$ 11,006,211	$ -	$ -	11,006,211	-$ 341,635	-$ 246,297	$ -	-587,931	10,418,279
1	1610	Miscellaneous Intangible Plant	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
12	1611	Computer Software (Formally known as Account 1925) - 5 yr	$ 926,574	$ -	$ -	926,574	-$ 902,581	-$ 10,391	$ -	-912,972	13,602
12	1611A	Computer Software (Formally known as Account 1925) - 10 yr	$ 2,269,762	$ 108,805	$ -	2,378,567	-$ 1,994,832	-$ 78,283	$ -	-2,073,115	305,452
47	1612	Land Rights (Formally known as Account 1906 and 1806) - 40 Years	$ 23,527,809	$ 3,009,755	$ -	26,537,564	-$ 8,977,814	-$ 639,996	$ -	-9,617,810	16,919,754
47	1612	Land Rights (Formally known as Account 1906 and 1806) - 10 Years	$ -	$ 542,000	$ -	542,000	$ -	-$ 27,100	$ -	-27,100	514,900
N/A	1805	Land	$ 1,776,866	$ -	$ -	1,776,866	$ -	$ -	$ -	0	1,776,866
47	1808	Buildings - Fixtures	$ 2,143,803	$ -	$ -	2,143,803	-$ 491,514	-$ 42,123	$ -	-533,637	1,610,166
47	1808A	Buildings - Components	$ 1,050,447	$ 103,366	$ -	1,153,813	-$ 254,813	-$ 43,383	$ -	-298,197	855,616
13	1810	Leasehold Improvements	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1820	Distribution Station Equipment <50 kV - Stations	$ 20,576,441	$ -	$ -	20,576,441	-$ 5,895,383	-$ 395,725	$ -	-6,291,108	14,285,333
47	1820A	Distribution Station Equipment <50 kV - Switches/Breakers	$ 2,495,949	$ 31,226	$ -	2,527,175	-$ 931,223	-$ 58,867	$ -	-990,090	1,537,086
47	1825	Storage Battery Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1830	Poles, Towers & Fixtures	$ 93,970,909	$ 3,679,903	$ -	97,650,812	-$ 32,337,031	-$ 1,892,302	$ -	-34,229,333	63,421,479
47	1835	Overhead Conductors & Devices	$ 59,040,585	$ 2,631,440	$ -	61,672,025	-$ 18,082,242	-$ 1,211,067	$ -	-19,293,309	42,378,716
47	1840	Underground Conduit	$ 33,543	$ -	$ -	33,543	-$ 2,069	-$ 671	$ -	-2,740	30,803
47	1845	Underground Conductors & Devices	$ 2,433,127	$ 186,047	$ -	2,619,174	-$ 828,984	-$ 58,305	$ -	-887,289	1,731,885
47	1850	Line Transformers	$ 16,965,753	$ 741,111	$ -	17,706,864	-$ 8,315,537	-$ 332,658	$ -	-8,648,195	9,058,669
47	1855	Services (Overhead & Underground)	$ 3,361,906	$ -	$ -	3,361,906	-$ 2,584,119	-$ 41,022	$ -	-2,625,141	736,765
47	1860	Meters	$ 688,153	$ -	$ -	688,153	-$ 614,632	-$ 13,816	$ -	-628,448	59,705
47	1860A	Meters (Smart Meters)	$ 4,752,545	$ 522,873	$ -	5,275,418	-$ 3,831,624	-$ 198,403	$ -	-4,030,028	1,245,390
47	1860B	Meters - PT's and CT's	$ 525,879	$ 12,929	$ -	538,809	-$ 205,533	-$ 16,853	$ -	-222,385	316,423
47	1865	Other Installations on Customer's Premises	$ 194,063	$ -	$ -	194,063	-$ 194,063	$ -	$ -	-194,063	0
N/A	1905	Land	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
1	1908	Buildings & Fixtures	$ 15,237,022	$ -	$ -	15,237,022	-$ 623,075	-$ 304,748	$ -	-927,823	14,309,199
1	1908A	Buildings & Fixtures-25Yrs	$ 47,721	$ 41,372	$ -	89,093	-$ 1,600	-$ 2,736	$ -	-4,336	84,757
12	1910	Leasehold Improvements	$ 101,365	$ -	$ -	101,365	-$ 95,751	-$ 3,706	$ -	-99,457	1,908
8	1915	Office Furniture & Equipment (10 years)	$ 413,440	$ 69,128	$ -	482,568	-$ 322,672	-$ 18,432	$ -	-341,104	141,464
8	1915A	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
50	1920	Computer Equipment - Hardware	$ 1,398,545	$ 51,533	$ -	1,450,078	-$ 1,052,770	-$ 128,840	$ -	-1,181,609	268,469
45	1920A	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
50	1920B	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
10	1930	Transportation Equipment - 5 Yr	$ 1,948,707	$ -	$ -	1,948,707	-$ 1,075,717	-$ 238,806	$ -	-1,314,523	634,185
10	1930A	Transportation Equipment - 10 Yr	$ 4,895,545	$ 607,470	$ -	5,503,015	-$ 3,167,949	-$ 375,833	$ -	-3,543,782	1,959,233
10	1935	Stores Equipment	$ 55,244	$ -	$ -	55,244	-$ 10,129	-$ 5,525	$ -	-15,654	39,590
8	1940	Tools, Shop & Garage Equipment	$ 2,074,505	$ 91,800	$ -	2,166,305	-$ 1,770,290	-$ 57,901	$ -	-1,828,191	338,114
10	1945	Measurement & Testing Equipment	$ 273,661	$ -	$ -	273,661	-$ 242,850	-$ 6,104	$ -	-248,954	24,707
10	1950	Power Operated Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
10	1955	Communications Equipment - 10 yr	$ 607,024	$ 106,730	$ -	713,754	-$ 482,618	-$ 21,838	$ -	-504,456	209,298
10	1955A	Communications Equipment - 5 yr	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1955B	Communication Equipment (Smart Meters)	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ 159,310	$ -	$ -	159,310	-$ 94,285	-$ 9,927	$ -	-104,212	55,098
8	1960A	Miscellaneous Equipment - 5 yr	$ 49,406	$ -	$ -	49,406	-$ 35,182	-$ 4,608	$ -	-39,790	9,616
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1980	System Supervisor Equipment	$ 436,489	$ -	$ -	436,489	-$ 78,639	-$ 34,424	$ -	-113,063	323,426
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1990	Other Tangible Property	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
47	1995	Contributions & Grants	-$ 7,249,135	-$ 100,000	$ -	-7,349,135	$ 372,236	$ 162,369	$ -	534,604	-6,814,531
		Sub-Total	**$ 268,233,461**	**$ 12,437,490**	**$ -**	**$ 280,670,950**	**-$ 95,473,562**	**-$ 6,362,750**	**$ -**	**-$ 101,836,312**	**$ 178,834,638**
		Less Socialized Renewable Energy Generation Investments (input as negative)									
		Less Other Non Rate-Regulated Utility Assets (input as negative)									
		Total PP&E for Rate Base Purposes	**$ 268,233,461**	**$ 12,437,490**	**$ -**	**$ 280,670,950**	**-$ 95,473,562**	**-$ 6,362,750**	**$ -**	**-$ 101,836,312**	**$ 178,834,638**
	2055	**Add: Construction Work in Progress - Electric**	-$ 1,139,680	-$ 400,000	$ -	-1,539,680	$ -	$ -	$ -	0	-1,539,680
		Less Other Non Rate-Regulated Utility Assets (input as negative)				**0**				**0**	**0**
		Total PP&E	**267,093,780**	**12,037,490**	**0**	**279,131,270**	**-95,473,562**	**-6,362,750**	**0**	**-101,836,312**	**177,294,958**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						-6,362,750			$ -

Less: Fully Allocated Depreciation	
Transportation	-$ 614,639
Stores Equipment	
Deferred Revenue	
Net Depreciation	-5,748,111

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Commodity Expense

Step 1: **Commodity Pricing**

Forecasted Commodity Prices

Table 1: Average RPP Supply Cost Summary*

			non-RPP	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$35.66	$35.66
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$66.64	$66.64
Adjustments ($/MWh)				($2.93)
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$99.37**

Step 2: **Commodity Expense**

(volumes for the test year is loss adjusted)

Commodity

Customer		**Revenue**	**Expense**		**2025 Test Year**					
Class Name	UoM	USoA #	USoA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705	-		750,096	107,022,828	$ 0.03566	$ 0.09937	$10,661,607
GS < 50	kWh	4010	4705	-		4,060,523	27,707,930	$ 0.03566	$ 0.09937	$2,898,135
GS > 50	kWh	4035	4705	159,142,793		22,237,031	6,162,088	$ 0.03566	$ 0.09937	$7,080,331
Seasonal	kWh	4010	4705	-		10,680	6,471,123	$ 0.03566	$ 0.09937	$643,416
Street Light	kWh	4025	4705	-		582,993	-	$ 0.03566	$ 0.09937	$20,790
	kWh	4025	4705					$ 0.03566	$ 0.09937	$0
	kWh	4025	4705					$ 0.03566	$ 0.09937	$0
	kWh	4025	4705					$ 0.03566	$ 0.09937	$0
	kWh	4025	4705					$ 0.03566	$ 0.09937	$0
	kWh	4025	4705					$ 0.03566	$ 0.09937	$0
	kWh	4025	4705					$ 0.03566	$ 0.09937	$0
TOTAL										**$21,304,279**

Class A - non-RPP Global Adjustment

					2025			
Customer		**Revenue**	**Expense**		**kWh Volume**		**Hist. Avg GA/kWh *****	**Amount**
		4035	4707		159,142,793		0.0284	$4,522,538
		4010	4707					$0
		4010	4707					$0
		4010	4707					$0
		4010	4707					$0
				-	159,142,793			**$4,522,538**

Class B - non-RPP Global Adjustment

					2025					
Customer		**Revenue**	**Expense**							Amount
Class Name	UoM	USoA #	USoA #			Class B Non-RPP Volume			GA Rate/kWh	
Residential	kWh	4006	4707			750,096			$ 0.06664	$49,986
GS < 50	kWh	4010	4707			4,060,523			$ 0.06664	$270,593
GS > 50	kWh	4035	4707			22,237,031			$ 0.06664	$1,481,876
Seasonal	kWh	4010	4707			10,680			$ 0.06664	$712
Street Light	kWh	4025	4707			582,993			$ 0.06664	$38,851
	kWh	4025	4707			0			$ 0.06664	$0
	kWh	4025	4707			0			$ 0.06664	$0
	kWh	4025	4707			0			$ 0.06664	$0
	kWh	4025	4707			0			$ 0.06664	$0
	kWh	4025	4707			0			$ 0.06664	$0
	kWh	4025	4707			0			$ 0.06664	$0
Total Volume						**27,641,323**				
TOTAL										**$1,842,018**

*Regulated Price Plan Prices for the Period November 1, 2023 to October 31, 2024, p. 5

** Enter 2024 load forecast data by class based on the most recent 12-month historic Class A and Class B RPP/Non-RPP proportions

*** Based on average $ GA per kWh billed to class A customers for most recent 12-month historical year.

Cost of Power Calculation

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All Volume should be loss adjusted with the exception of:
1. Volume for Electricity Commodity, Wholesale Market Services, Class A and B should loss adjusted less WMP
2. Low Voltage Charges - No loss adjustment for kWh

		2025 Test Year	RPP		2025 Test Year	non-RPP		Total
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast								
Residential	kWh	107,022,828		10,634,858	750,096		26,748	
GS < 50	kWh	27,707,930		2,753,337	4,060,523		144,798	
GS > 50	kWh	6,162,088		612,327	181,379,824		6,468,005	
Seasonal	kWh	6,471,123		643,036	10,680		381	
Street Light	kWh	0		-	582,993		20,790	
		0		-	0		-	
		0		-	0		-	
		0		-	0		-	
		0		-	0		-	
		0		-	0		-	
		0		-	0		-	
SUB-TOTAL				14,643,558			6,660,722	$ 21,304,279

Global Adjustment non-RPP	Units	Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential - Class B	kWh			0			49,986	
GS < 50 - Class B	kWh			0			270,593	
GS > 50 - Class B	kWh			0			1,481,876	
Seasonal - Class B	kWh			0			712	
Street Light - Class B	kWh			0			38,851	
				0			-	
				0			-	
				0			-	
				0			-	
				0			-	
				0			-	
				0			4,522,538	
				0			-	
				0			-	
				0			-	
				0			-	
SUB-TOTAL				0			6,364,556	$ 6,364,556

Transmission - Network		Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh	107,022,828	0.0115	1,231,069	750,096	0.0115	8,628	
GS < 50	kWh	27,707,930	0.0115	318,721	4,060,523	0.0115	46,708	
GS > 50	kW	11,356	4.3825	49,768	334,266	4.3825	1,464,918	
Seasonal	kWh	6,471,123	0.0115	74,436	10,680	0.0115	123	
Street Light	kW	-	3.1734	-	1,497	3.1734	4,752	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				1,673,995			1,525,128	3,199,123

Transmission - Connection							$	Total
Class per Load Forecast								
Residential	kWh	107,022,828	0.0081	864,224	750,096	0.0081	6,057	
GS < 50	kWh	27,707,930	0.0081	223,745	4,060,523	0.0081	32,789	
GS > 50	kW	11,356	3.0699	34,863	334,266	3.0699	1,026,180	
Seasonal	kWh	6,471,123	0.0081	52,255	10,680	0.0081	86	
Street Light	kW	-	2.2146	-	1,497	2.2146	3,316	
				-	-		-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				1,175,088			1,068,429	2,243,517

Wholesale Market Service								
Class per Load Forecast							$	Total
Residential	kWh	107,022,828	0.0041	438,794	750,096	0.0041	3,075	
GS < 50	kWh	27,707,930	0.0041	113,603	4,060,523	0.0041	16,648	
GS > 50	kWh	6,162,088	0.0041	25,265	181,379,824	0.0041	743,657	
Seasonal	kWh	6,471,123	0.0041	26,532	10,680	0.0041	44	
Street Light	kWh	-	0.0041	-	582,993	0.0041	2,390	
	kWh	-		-	-		-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				604,192			765,815	1,370,007

Class A CBR								
Class per Load Forecast							$	Total
Residential				-			-	
GS < 50				-			-	
GS > 50				-	159,142,793	0.0002	29,308	
Seasonal				-			-	
Street Light				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				-			29,308	29,308

Class B CBR								
Class per Load Forecast							$	Total
Residential	kWh	107,022,828	0.0004	42,809	750,096	0.0004	300	
GS < 50	kWh	27,707,930	0.0004	11,083	4,060,523	0.0004	1,624	
GS > 50	kWh	6,162,088	0.0004	2,465	22,237,031	0.0004	8,895	
Seasonal	kWh	6,471,123	0.0004	2,588	10,680	0.0004	4	
Street Light	kWh	-	0.0004	-	582,993	0.0004	233	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				58,946			11,057	70,002

RRRP								
Class per Load Forecast							$	Total
Residential		107,022,828	0.0014	149,832	750,096	0.0014	1,050	
GS < 50		27,707,930	0.0014	38,791	4,060,523	0.0014	5,685	
GS > 50		6,162,088	0.0014	8,627	181,379,824	0.0014	253,932	
Seasonal		6,471,123	0.0014	9,060	10,680	0.0014	15	
Street Light		-	0.0014	-	582,993	0.0014	816	
		-	0.0014	-	-	0.0014	-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				206,310			261,498	467,807

Low Voltage - No TLF adjustment								
Class per Load Forecast							$	Total
Residential				-			-	
GS < 50				-			-	
GS > 50				-			-	
Seasonal				-			-	
Street Light				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				-			-	-

Smart Meter Entity Charge								
Class per Load Forecast							$	Total
Residential	# Cust	8,159	0.42	41,121	476	0.42	2,399	
GS < 50	# Cust	902	0.42	4,544	169	0.42	852	
Seasonal	# Cust	2,714	0.42	13,680	4	0.42	23	
				-			-	
				-			-	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				59,345			3,273	62,618
SUB- TOTAL				18,421,432			16,689,785	35,111,217
OER CREDIT	13.1%			(2,413,208)			0	(2,413,208)
TOTAL				**16,008,225**			**16,689,785**	**32,698,009**

3.The OER Credit will only apply to RPP proportion of the listed components. Impacts on distribution charges are excluded for the purpose of calculating the cost of power.
4. Class A CBR: use the average CBR per kWh, similar to how the Class A GA cost is calculated

2025 Test Year - Cop		
4705 -Power Purchased	$	21,304,279
4707- Global Adjustment	$	6,364,556
4708-Charges-WMS	$	1,937,124
4714-Charges-NW	$	3,199,123
4716-Charges-CN	$	2,243,517
4750-Charges-LV	$	-
4751-IESO SME	$	62,618
Misc A/R or A/P	$	(2,413,208)
TOTAL	**$**	**32,698,009**

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Settlement Proposal – Proposed Tariff and Bill Impacts

Algoma Power Inc.
EB-2024-0007

Algoma Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

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

RESIDENTIAL R1 SERVICE CLASSIFICATION

For the purposes of rates and charges, a residential service is defined in two ways:

This application refers to a Residential service with a demand of less then, or is forecast to be less than, 50 kilowatts, and which is billed on an energy basis. Class B consumers are defined in accordance with 0. Reg. 429/04. Futher servicing details are available in the distributor's Condition 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 - Applicable only to customers that meet criteria (i) above	$	67.36
Rate Rider for Refund of Interim Licence Deferral Account - effective until December 31, 2025 Applicable only for customers in the Township of Dubreuilville	$	(6.70)
Rate Rider for Group 2 Accounts - effective until December 31, 2025	$	(1.65)
Rate Rider for Disposition of Accounts 1575 and 1576 - effective until December 31, 2025	$	0.30
Service Charge - Applicable only to customers that meet criteria (ii) above	$	30.21
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate - Applicable only to customers that meet criteria (ii) above	$/kWh	0.0425
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until December 31, 2025	$/kWh	0.0002
Rate Rider for Global Adjustment - effective until December 31, 2025	$/kWh	0.0000
Rate Rider for Group 1 Accounts - effective until December 31, 2025	$/kWh	(0.0007)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0115
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0081

MONTHLY RATES AND CHARGES - Regulatory Component

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	0.0014
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

RESIDENTIAL R2 SERVICE CLASSIFICATION

This classification refers to a Residential service with a demand equal to or greater than, or is forecast to be equal to or greater than, 50 kilowatts, and which is billed on a demand basis. Class A and Class B consumers are defined in accordance with 0. 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	$	777.31
Distribution Volumetric Rate	$/kW	4.0276
Rate Rider for Refund of Interim Licence Deferral Account - effective until December 31, 2025 Applicable only for customers in the Township of Dubreuilville	$	(6.70)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until December 31, 2025	$/kW	0.1932
Rate Rider for Disposition of Accounts 1575 and 1576 - effective until December 31, 2025	$/kW	0.1380
Rate Rider for Global Adjustment - effective until December 31, 2025	$/kWh	0.0000
Rate Rider for Group 1 Accounts - effective until December 31, 2025	$/kW	(0.4305)
Rate Rider for Group 2 Accounts - effective until December 31, 2025	$/kW	(1.3160)
Retail Transmission Rate - Network Service Rate	$/kW	4.3825
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.0699

MONTHLY RATES AND CHARGES - Regulatory Component

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	0.0014
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SEASONAL CUSTOMERS SERVICE CLASSIFICATION

This classification includes all services supplied to single-family dwelling units for domestic purposes, which are occupied on a seasonal/intermittent basis. A service is defined as Seasonal if occupancy is for a period of less than eight months of the year. Class B consumers are defined in accordance with O. Reg. 429. 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	$	99.16
Rate Rider for Group 2 Accounts - effective until December 31, 2025	$	(3.80)
Rate Rider for Disposition of Accounts 1575 and 1576 - effective until December 31, 2025	$	0.05
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate	$/kWh	0.0460
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until December 31, 2025	$/kWh	0.0002
Rate Rider for Global Adjustment - effective until December 31, 2025	$/kWh	0.0000
Rate Rider for Group 1 Accounts - effective until December 31, 2025	$/kWh	(0.0014)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0115
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0081

MONTHLY RATES AND CHARGES - Regulatory Component

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	0.0014
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. The consumption for these unmetered accounts will be based on the calculated connection load times the calculated hours of use established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429. 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 device)	$	2.24
Distribution Volumetric Rate	$/kWh	0.3624
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until December 31, 2025	$/kWh	0.0002
Rate Rider for Disposition of Accounts 1575 and 1576 - effective until December 31, 2025	$/kWh	0.0003
Rate Rider for Global Adjustment - effective until December 31, 2025	$/kWh	0.0000
Rate Rider for Group 1 Accounts - effective until December 31, 2025	$/kWh	(0.0025)
Rate Rider for Group 2 Accounts - effective until December 31, 2025	$/kWh	(0.0161)
Retail Transmission Rate - Network Service Rate	$/kW	3.1734
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2146

MONTHLY RATES AND CHARGES - Regulatory Component

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	0.0014
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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 & 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

Arrears certificate (credit reference)	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
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 at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole - during regular hours	$	185.00
Reconnection at pole - after regular hours	$	415.00

Other

Specific charge for access to the power poles - per pole/year		39.14
(with the exception of wireless attachments)		
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00

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 Algoma Power Inc. to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	121.23
Monthly fixed charge, per retailer	$	48.50
Monthly variable charge, per customer, per retailer	$/cust.	1.20
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.71
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.71)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.61
Processing fee, per request, applied to the requesting party	$	1.20
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)	$	4.85
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)	$	2.42

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	1.0873
Total Loss Factor - Primary Metered Customer	1.0765

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 R1(i)	kwh	RPP	1.0829	1.0873	750		CONSUMPTION	1
Residential R1(ii)	kwh	RPP	1.0829	1.0873	2,000	-	CONSUMPTION	1
Residential R2	kw	Non-RPP (Other	1.0829	1.0873	225,000	500	DEMAND	1
Seasonal	kwh	RPP	1.0829	1.0873	200		CONSUMPTION	1
Seasonal-10th percentile	kw	Non-RPP (Other	1.0829	1.0873	15		DEMAND	1
Street Lighting	kwh	RPP	1.0829	1.0873	3,000	10	CONSUMPTION	75

	Sub-Total A		Sub-Total B		Sub-Total C		Total Bill	
Classification	$	%	$	%	$	%	$	%
Residential R1(i)	$ (1.35)	-3.25%	$ (3.91)	-7.75%	$ (3.30)	-5.01%	$ (3.27)	-2.25%
Residential R1(ii)	$ 3.82	3.47%	$ (3.02)	-2.26%	$ (1.38)	-0.79%	$ (1.33)	-0.34%
Residential R2	$ (442.72)	-16.74%	$ (1,397.41)	-40.15%	$ (1,268.24)	-17.92%	$ (1,314.91)	-3.55%
Seasonal	$ 8.58	8.96%	$ 8.26	8.41%	$ 8.43	8.23%	$ 8.42	6.80%
Seasonal-10th percentile	$ 7.43	8.39%	$ 7.41	8.31%	$ 7.42	8.29%	$ 7.42	8.12%
Street Lighting	$ (67.21)	-5.27%	$ (84.72)	-6.59%	$ (82.85)	-6.19%	$ (81.37)	-4.79%

	Distribution				Total Bill			
Classification	Current Bill	2025 Proposed	Change ($)	Change (%)	Current Bill	2025 Proposed	Change ($)	Change (%)
Residential R1(i)	$ 41.39	$ 40.04	$ (1.35)	-3.3%	$ 145.63	$ 142.36	$ (3.27)	-2.25%
Residential R1(ii)	$ 110.04	$ 113.86	$ 3.82	3.5%	$ 386.91	$ 385.59	$ (1.33)	-0.34%
Residential R2	$ 2,644.81	$ 2,202.09	$ (442.72)	-16.7%	$ 37,089.41	$ 35,774.49	$ (1,314.91)	-3.55%
Seasonal	$ 95.75	$ 104.33	$ 8.58	9.0%	$ 123.77	$ 132.19	$ 8.42	6.80%
Seasonal-10th percentile	$ 88.65	$ 96.08	$ 7.43	8.4%	$ 91.29	$ 98.70	$ 7.42	8.12%
Street Lighting	$ 1,275.00	$ 1,207.79	$ (67.21)	-5.3%	$ 1,697.82	$ 1,616.44	$ (81.37)	-4.79%

Customer Class:	Residential R1(i)
RPP / Non-RPP:	RPP
Consumption	750 kWh
Customers/ Connections	1
Demand	- kW
Current Loss Factor	1.0829
posed/Approved Loss Factor	1.0873

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 64.31	1	$ 64.31	$ 67.36	1	$ 67.36	$ 3.05	4.74%
Distribution Volumetric Rate		750	$ -		750	$ -	$ -	
			$ -			$ -		
DRP Adjustment	-$ 22.92	1	$ (22.92)	-$ 25.97	1	$ (25.97)	$ (3.05)	13.31%
Fixed Rate Riders		1	$ -	$ (1.35)	1	$ (1.35)	$ (1.35)	
Volumetric Rate Riders		750	$ -		750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 41.39**			**$ 40.04**	**$ (1.35)**	-3.25%
Line Losses on Cost of Power	$ 0.0999	62	$ 6.21	$ 0.0999	65	$ 6.54	$ 0.33	5.31%
Total Deferral/Variance Account Rate Riders	$ 0.0035	750	$ 2.63	$ (0.0007)	750	$ (0.56)	$ (3.18)	-121.21%
CBR Class B Rate Riders	$ (0.0002)	750	$ (0.15)	$ 0.0002	750	$ 0.14	$ 0.29	-190.76%
GA Rate Riders		750	$ -			$ -	$ -	
Low Voltage Service Charge		750	$ -			$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders		1	$ -			$ -	$ -	
Additional Volumetric Rate Riders		750	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 50.49**			**$ 46.58**	**$ (3.91)**	-7.75%
RTSR - Network	$ 0.0108	812	$ 8.77	$ 0.0115	815	$ 9.38	$ 0.61	6.94%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0081	812	$ 6.58	$ 0.0081	815	$ 6.59	$ 0.01	0.10%
Sub-Total C - Delivery (including Sub-Total B)			**$ 65.84**			**$ 62.55**	**$ (3.30)**	-5.01%
Wholesale Market Service Charge (WMSC)	$ 0.0045	812	$ 3.65	$ 0.0045	815	$ 3.67	$ 0.01	0.41%
Rural and Remote Rate Protection (RRRP)	$ 0.0014	812	$ 1.14	$ 0.0014	815	$ 1.14	$ 0.00	0.41%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)			$ -					
TOU - Off Peak	$ 0.0760	473	$ 35.91	$ 0.0760	473	$ 35.91	$ -	0.00%
TOU - Mid Peak	$ 0.1220	135	$ 16.47	$ 0.1220	135	$ 16.47	$ -	0.00%
TOU - On Peak	$ 0.1580	143	$ 22.52	$ 0.1580	143	$ 22.52	$ -	0.00%
Non-RPP Retailer Avg. Price			$ -			$ -	$ -	
Average IESO Wholesale Market Price			$ -			$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 145.78**			**$ 142.50**	**$ (3.28)**	-2.25%
HST	13%		$ 18.95	13%		$ 18.53	$ (0.43)	-2.25%
Ontario Electricity Rebate	13.1%		$ (19.10)	13.1%		$ (18.67)	$ 0.43	-2.25%
Total Bill on TOU			**$ 145.63**			**$ 142.36**	**$ (3.27)**	-2.25%

Customer Class:	Residential R1(ii)	
RPP / Non-RPP:	RPP	
Consumption	2,000	kWh
Customers/ Connections	1	
Demand	-	kW
Current Loss Factor	1.0829	
posed/Approved Loss Factor	1.0873	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28.84	1	$ 28.84	$ 30.21	1	$ 30.21	$ 1.37	4.75%
Distribution Volumetric Rate	$ 0.0406	2,000	$ 81.20	$ 0.0425	2,000	$ 85.00	$ 3.80	4.68%
			$ -			$ -		
DRP Adjustment			$ -				$ -	
Fixed Rate Riders		1	$ -	$ (1.35)	1	$ (1.35)	$ (1.35)	
Volumetric Rate Riders		2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)			$ 110.04			$ 113.86	$ 3.82	3.47%
Line Losses on Cost of Power	$ 0.0999	166	$ 16.56	$ 0.0999	175	$ 17.44	$ 0.88	5.31%
Total Deferral/Variance Account Rate Riders	$ 0.0035	2,000	$ 7.00	$ (0.0007)	2,000	$ (1.48)	$ (8.48)	-121.21%
CBR Class B Rate Riders	$ (0.0002)	2,000	$ (0.40)	$ 0.0002	2,000	$ 0.36	$ 0.76	-190.76%
GA Rate Riders			$ -			$ -	$ -	
Low Voltage Service Charge			$ -			$ -	$ -	
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		2,000	$ -		2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			$ 133.62			$ 130.60	$ (3.02)	-2.26%
RTSR - Network	$ 0.0108	2,166	$ 23.39	$ 0.0115	2,175	$ 25.01	$ 1.62	6.94%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0081	2,166	$ 17.54	$ 0.0081	2,175	$ 17.56	$ 0.02	0.10%
Sub-Total C - Delivery (including Sub-Total B)			$ 174.55			$ 173.17	$ (1.38)	-0.79%
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,166	$ 9.75	$ 0.0045	2,175	$ 9.79	$ 0.04	0.41%
Rural and Remote Rate Protection (RRRP)	$ 0.0014	2,166	$ 3.03	$ 0.0014	2,175	$ 3.04	$ 0.01	0.41%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)			$ -					
TOU - Off Peak	$ 0.0760	1,260	$ 95.76	$ 0.0760	1,260	$ 95.76	$ -	0.00%
TOU - Mid Peak	$ 0.1220	360	$ 43.92	$ 0.1220	360	$ 43.92	$ -	0.00%
TOU - On Peak	$ 0.1580	380	$ 60.04	$ 0.1580	380	$ 60.04	$ -	0.00%
Non-RPP Retailer Avg. Price			$ -			$ -	$ -	
Average IESO Wholesale Market Price			$ -			$ -	$ -	
Total Bill on TOU (before Taxes)			$ 387.30			$ 385.97	$ (1.33)	-0.34%
HST	13%		$ 50.35	13%		$ 50.18	$ (0.17)	-0.34%
Ontario Electricity Rebate	13.1%		$ (50.74)	13.1%		$ (50.56)	$ 0.17	-0.34%
Total Bill on TOU			$ 386.91			$ 385.59	$ (1.33)	-0.34%

Customer Class:	Residential R2
RPP / Non-RPP:	Non-RPP
Consumption	225,000 kWh
Customers/ Connections	1
Demand	500 kW
Current Loss Factor	1.0829
posed/Approved Loss Factor	1.0873

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 742.06	1	$ 742.06	$ 777.31	1	$ 777.31	$ 35.25	4.75%
Distribution Volumetric Rate	$ 3.8450	500	$ 1,922.50	$ 4.0276	500	$ 2,013.80	$ 91.30	4.75%
			$ -			$ -		
DRP Adjustment			$ -				$ -	
Fixed Rate Riders		1	$ -	$ 0.00	1	$ 0.00	$ 0.00	
Volumetric Rate Riders	$ (0.0395)	500	$ (19.75)	$ (1.1781)	500	$ (589.03)	$ (569.28)	2882.41%
Sub-Total A (excluding pass through)			**$ 2,644.81**			**$ 2,202.09**	**$ (442.72)**	-16.74%
Line Losses on Cost of Power	$ -		$ -	$ -		$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 1.7434	500	$ 871.70	$ (0.4305)	500	$ (215.24)	$ (1,086.94)	-124.69%
CBR Class B Rate Riders	$ (0.0713)	500	$ (35.65)	$ 0.1932	500	$ 96.61	$ 132.26	-370.98%
GA Rate Riders			$ -	$ -	225,000	$ -	$ -	
Low Voltage Service Charge			$ -			$ -	$ -	
Smart Meter Entity Charge (if applicable)		1	$ -		1	$ -	$ -	
Additional Fixed Rate Riders		1	$ -		1	$ -	$ -	
Additional Volumetric Rate Riders		225,000	$ -		225,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3,480.86**			**$ 2,083.45**	**$ (1,397.41)**	-40.15%
RTSR - Network	$ 4.1147	500	$ 2,057.35	$ 4.3825	500	$ 2,191.24	$ 133.89	6.51%
RTSR - Connection and/or Line and Transformation Connection	$ 3.0794	500	$ 1,539.70	$ 3.0699	500	$ 1,534.97	$ (4.73)	-0.31%
Sub-Total C - Delivery (including Sub-Total B)			**$ 7,077.91**			**$ 5,809.67**	**$ (1,268.24)**	-17.92%
Wholesale Market Service Charge (WMSC)	$ 0.0045	243,653	$ 1,096.44	$ 0.0045	244,643	$ 1,100.89	$ 4.45	0.41%
Rural and Remote Rate Protection (RRRP)	$ 0.0014	243,653	$ 341.11	$ 0.0014	244,643	$ 342.50	$ 1.39	0.41%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)			$ -					
TOU - Off Peak	$ -	-	$ -	$ -	-	$ -	$ -	
TOU - Mid Peak	$ -	-	$ -	$ -	-	$ -	$ -	
TOU - On Peak	$ -	-	$ -	$ -	-	$ -	$ -	
Non-RPP Retailer Avg. Price			$ -			$ -	$ -	
Average IESO Wholesale Market Price	$ 0.0998	243,653	$ 24,306.77	$ 0.0998	244,643	$ 24,405.54	$ 98.76	0.41%
Total Bill on TOU (before Taxes)			**$ 32,822.48**			**$ 31,658.85**	**$ (1,163.64)**	-3.55%
HST	13%		$ 4,266.92	13%		$ 4,115.65	$ (151.27)	-3.55%
Ontario Electricity Rebate	0.0%		$ -	0.0%		$ -	$ -	
Total Bill on TOU			**$ 37,089.41**			**$ 35,774.49**	**$ (1,314.91)**	-3.55%

Customer Class:	Seasonal
RPP / Non-RPP:	RPP
Consumption	200 kWh
Customers/ Connections	1
Demand	- kW
Current Loss Factor	1.0829
posed/Approved Loss Factor	1.0873

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 82.79	1	$ 82.79	$ 99.16	1	$ 99.16	$ 16.37	19.77%
Distribution Volumetric Rate	$ 0.0384	200	$ 7.68	$ 0.0460	200	$ 9.20	$ 1.52	19.79%
			$ -			$ -		
DRP Adjustment		1	$ -					
Fixed Rate Riders	$ 5.28	1	$ 5.28	$ (3.75)	1	$ (3.75)	$ (9.03)	-171.00%
Volumetric Rate Riders		200	$ -	$ (0.0014)	200	$ (0.28)	$ (0.28)	
Sub-Total A (excluding pass through)			**$ 95.75**			**$ 104.33**	**$ 8.58**	8.96%
Line Losses on Cost of Power	$ 0.0999	17	$ 1.66	$ 0.0999	17	$ 1.74	$ 0.09	5.31%
Total Deferral/Variance Account Rate Riders	$ 0.0026	200	$ 0.52	$ 0.0002	200	$ 0.04	$ (0.48)	-93.02%
CBR Class B Rate Riders	$ (0.0002)	200	$ (0.04)	$ 0.0002	200	$ 0.04	$ 0.08	-190.76%
GA Rate Riders		200	$ -			$ -	$ -	
Low Voltage Service Charge		200	$ -			$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders		1	$ -			$ -	$ -	
Additional Volumetric Rate Riders		200	$ -			$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 98.31**			**$ 106.57**	**$ 8.26**	8.41%
RTSR - Network	$ 0.0108	217	$ 2.34	$ 0.0115	217	$ 2.50	$ 0.16	6.94%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0081	217	$ 1.75	$ 0.0081	217	$ 1.76	$ 0.00	0.10%
Sub-Total C - Delivery (including Sub-Total B)			**$ 102.40**			**$ 110.83**	**$ 8.43**	8.23%
Wholesale Market Service Charge (WMSC)	$ 0.0045	217	$ 0.97	$ 0.0045	217	$ 0.97	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0014	217	$ 0.30	$ 0.0014	217	$ 0.30	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)			$ -					
TOU - Off Peak	$ 0.0760	126	$ 9.58	$ 0.0760	126	$ 9.58	$ -	0.00%
TOU - Mid Peak	$ 0.1220	36	$ 4.39	$ 0.1220	36	$ 4.39	$ -	0.00%
TOU - On Peak	$ 0.1580	38	$ 6.00	$ 0.1580	38	$ 6.00	$ -	0.00%
Non-RPP Retailer Avg. Price			$ -			$ -	$ -	
Average IESO Wholesale Market Price			$ -			$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 123.90**			**$ 132.33**	**$ 8.43**	6.80%
HST	13%		$ 16.11	13%		$ 17.20	$ 1.10	6.80%
Ontario Electricity Rebate	13.1%		$ (16.23)	13.1%		$ (17.33)	$ (1.10)	6.80%
Total Bill on TOU			**$ 123.77**			**$ 132.19**	**$ 8.42**	6.80%

Customer Class:	Seasonal-10th percentile	
RPP / Non-RPP:	RPP	
Consumption	15	kWh
Customers/ Connections	1	
Demand	-	kW
Current Loss Factor	1.0829	
posed/Approved Loss Factor	1.0873	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 82.79	1	$ 82.79	$ 99.16	1	$ 99.16	$ 16.37	19.77%
Distribution Volumetric Rate	$ 0.0384	15	$ 0.58	$ 0.0460	15	$ 0.69	$ 0.11	19.79%
			$ -	$ -		$ -		
DRP Adjustment		1	$ -	$ -				
Fixed Rate Riders	$ 5.28	1	$ 5.28	$ (3.75)	1	$ (3.75)	$ (9.03)	-171.00%
Volumetric Rate Riders		15	$ -	$ (0.00139)	15	$ (0.02)	$ (0.02)	
Sub-Total A (excluding pass through)			**$ 88.65**			**$ 96.08**	**$ 7.43**	8.39%
Line Losses on Cost of Power	$ 0.0999	1	$ 0.12	$ 0.10	1	$ 0.13	$ 0.01	5.31%
Total Deferral/Variance Account Rate Riders	$ 0.0026	15	$ 0.04	$ 0.00	15	$ 0.00	$ (0.04)	-93.02%
CBR Class B Rate Riders	$ (0.0002)	15	$ (0.00)	$ 0.00	15	$ 0.00	$ 0.01	-190.76%
GA Rate Riders		15	$ -	$ -		$ -	$ -	
Low Voltage Service Charge		15	$ -	$ -		$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders		1	$ -	$ -		$ -	$ -	
Additional Volumetric Rate Riders		15	$ -	$ -		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 89.23**			**$ 96.64**	**$ 7.41**	8.31%
RTSR - Network	$ 0.0108	16	$ 0.18	$ 0.01	16	$ 0.19	$ 0.01	6.94%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0081	16	$ 0.13	$ 0.01	16	$ 0.13	$ 0.00	0.10%
Sub-Total C - Delivery (including Sub-Total B)			**$ 89.53**			**$ 96.96**	**$ 7.42**	8.29%
Wholesale Market Service Charge (WMSC)	$ 0.0045	16	$ 0.07	$ 0.0045	16	$ 0.07	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0014	16	$ 0.02	$ 0.0014	16	$ 0.02	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)			$ -	$ -				
TOU - Off Peak	$ 0.0760	9	$ 0.72	$ 0.0760	9	$ 0.72	$ -	0.00%
TOU - Mid Peak	$ 0.1220	3	$ 0.33	$ 0.1220	3	$ 0.33	$ -	0.00%
TOU - On Peak	$ 0.1580	3	$ 0.45	$ 0.1580	3	$ 0.45	$ -	0.00%
Non-RPP Retailer Avg. Price			$ -			$ -	$ -	
Average IESO Wholesale Market Price			$ -			$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 91.38**			**$ 98.80**	**$ 7.42**	8.12%
HST	13%		$ 11.88	13%		$ 12.84	$ 0.96	8.12%
Ontario Electricity Rebate	13.1%		$ (11.97)	13.1%		$ (12.94)	$ (0.97)	8.12%
Total Bill on TOU			**$ 91.29**			**$ 98.70**	**$ 7.42**	8.12%

Customer Class:	**Street Lighting**
RPP / Non-RPP:	**Non-RPP**
Consumption	**3,000** kWh
Customers/ Connections	**75**
Demand	**10** kW
Current Loss Factor	**1.0829**
posed/Approved Loss Factor	**1.0873**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2.08	75	$ 156.00	$ 2.24	75	$ 168.00	$ 12.00	7.69%
Distribution Volumetric Rate	$ 0.3361	3,000	$ 1,008.30	$ 0.3624	3,000	$ 1,087.20	$ 78.90	7.83%
			$ -			$ -		
DRP Adjustment			$ -				$ -	
Fixed Rate Riders	$ 0.96	75	$ 72.00		75	$ -	$ (72.00)	-100.00%
Volumetric Rate Riders	$ 0.0129	3,000	$ 38.70	$ (0.0158)	3,000	$ (47.41)	$ (86.11)	-222.50%
Sub-Total A (excluding pass through)			**$ 1,275.00**			**$ 1,207.79**	**$ (67.21)**	-5.27%
Line Losses on Cost of Power	$ -		$ -	$ -		$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.0037	3,000	$ 11.10	$ (0.0025)	3,000	$ (7.56)	$ (18.66)	-168.11%
CBR Class B Rate Riders	$ (0.0002)	3,000	$ (0.60)	$ 0.0002	3,000	$ 0.54	$ 1.14	-190.76%
GA Rate Riders		3,000	$ -	$ -	3,000	$ -	$ -	
Low Voltage Service Charge			$ -			$ -	$ -	
Smart Meter Entity Charge (if applicable)			$ -		75	$ -	$ -	
Additional Fixed Rate Riders			$ -		75	$ -	$ -	
Additional Volumetric Rate Riders			$ -		3,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,285.50**			**$ 1,200.78**	**$ (84.72)**	-6.59%
RTSR - Network	$ 2.9795	10	$ 29.80	$ 3.1734	10	$ 31.73	$ 1.94	6.51%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2214	10	$ 22.21	$ 2.2146	10	$ 22.15	$ (0.07)	-0.31%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,337.51**			**$ 1,254.66**	**$ (82.85)**	-6.19%
Wholesale Market Service Charge (WMSC)	$ 0.0045	3,249	$ 14.62	$ 0.0045	3,262	$ 14.68	$ 0.06	0.41%
Rural and Remote Rate Protection (RRRP)	$ 0.0014	3,249	$ 4.55	$ 0.0014	3,262	$ 4.57	$ 0.02	0.41%
Standard Supply Service Charge	$ 0.25	75	$ 18.75	$ 0.25	75	$ 18.75	$ -	0.00%
Ontario Electricity Support Program (OESP)			$ -					
TOU - Off Peak	$ -	-	$ -	$ -	-	$ -	$ -	
TOU - Mid Peak	$ -	-	$ -	$ -	-	$ -	$ -	
TOU - On Peak	$ -	-	$ -	$ -	-	$ -	$ -	
Non-RPP Retailer Avg. Price			$ -			$ -	$ -	
Average IESO Wholesale Market Price	$ 0.0998	3,249	$ 324.09	$ 0.0998	3,262	$ 325.41	$ 1.32	0.41%
Total Bill on TOU (before Taxes)			**$ 1,699.52**			**$ 1,618.06**	**$ (81.46)**	-4.79%
HST	13%		$ 220.94	13%		$ 210.35	$ (10.59)	-4.79%
Ontario Electricity Rebate	13.1%		$ (222.64)	13.1%		$ (211.97)	$ 10.67	-4.79%
Total Bill on TOU			**$ 1,697.82**			**$ 1,616.44**	**$ (81.37)**	-4.79%

Settlement Proposal – Pre-Settlement Clarification Questions

Algoma Power Inc.
EB-2024-0007

ALGOMA POWER INC. (ALGOMA)
2025 RATE APPLICATION (EB-2024-0007)
PRE-SETTLEMENT FOLLOW-UP AND CLARIFICATION QUESTIONS

(numbering follows from SEC's IRs)

PSC-SEC-38

REFERENCE: Preamble to Interrogatory Responses and 2-Staff-28

a) Please provide further details on which section of the #4 circuit the customer is considering purchasing and what would be the estimated value of that portion of line.

API Response:

The estimated value of the portion of line is $1,526,554. This is comprised of the actual construction cost for the section of $1,091,709. This represents 19.6% of the project's total construction cost relevant to the customer, and accordingly API has also allocated 19.6% of the non-construction costs (Studies, Project Management, Land Rights, Contractor,etc.), adding another $434,937.

The project was in-service in November 2023, and API would propose to decrease the price of the assets in accordance with the accumulated amortization at the time of the sale.

Additionally, the assets relate to the portion of the project for which the customer paid a capital contribution. Accordingly, API would propose to reduce the purchase price by $588,770, representing the estimated portion of the assets that has been paid for through capital contribution.

PSC-SEC-39

REFERENCE: 2-Staff-29 Attachments

a) In the instances where Hydro One has stated '…if this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator, if the regulator wants it …' when Algoma asked for explanations of variances, please follow up with Hydro One and request that it be provided for purposes of this proceeding.

API Response:

Please see Attachment SEC-39.

PSC-SEC-40

REFERENCE 5-Staff-52

a) Please provide a copy of the terms for the original affiliate debt for $12.75M.

API Response:

Please see Attachment 5-Staff-52.

PSC-SEC-41

REFERENCE: 9-Staff-74

a) Please provide Algoma's spending for locates for 2020 – 2023 and the forecasts for 2024 and 2025.

API Response:

Actuals				Forecast	
2020	2021	2022	2023	2024	2025
$163,823.45	$159,616.49	$131,273.25	$138,659.71	$132,992.76	$135,599.28

As discussed in IR 9-Staff-74, API has assumed the continuation of the dedicated locator model will be used for dedicated broadband locates in 2024 and 2025.

PSC-SEC-42

REFERENCE: 2-SEC-9a

a) Algoma states that 2-AA and 2-AB are shown on an in-service basis. For 2024 total in-service additions are $14,026k. Cell E378 in 2-BA shows additions to PP&E of $13,671k (without the ACMs). Please explain and correct as required.
b) Construction work in progress (CWIP) represents capital dollars that have been spent but not yet put into service. Please explain what negative dollars in CWIP means.
c) Algoma states that '…in reality API expects some level of CWIP balance at the end of 2024 and 2025'. Please explain this further.
d) Algoma currently shows $14,026k in 2024 and $10,505k in 2025 for in-service additions. Is Algoma saying that it expects capex to be higher in each of these years? If so, please provide details of the expected additional capex.

API Response:

a) The variance is related to the planned spending in 2024 on the ACM projects, as outlined below:

2024 Additions per 2-AA/AB	$ 14,025,600.00
2024 Additions per 2-BA	$ 13,670,698.00
Variance to be explainted	**$ 354,902.00**
	2024 Spending on ACM Projects
ERTS	$ 154,279
SSM Facility	$ 200,622
Total Variance Explained by '24 ACM Spend	**$ 354,901**
Remaining Variance	-$ 1

b) A negative ending balance in CWIP would not typically be expected (though this could occur, for example, if a very large capital contribution was collected in a given year, before significant spending began on the project). API has reviewed the ending CWIP balance again in 2024, and determined that the offsetting increase to CWIP as a result of bringing significant capital contributions into service in 2024 (which were previously in WIP as of 2023) was not reflected in Appendix 2-BA. An adjusting entry of $4,164,289 has been made to the CWIP activity in 2024, bringing the closing balance to $2.6M – please see attached Chapter 2 Appendix document.

c) Please see adjustment identified in section b), which results in a positive CWIP balance for 2024 and 2025 consistent with the expectation quoted.

d) No, API expects its capital expenditures in line with the amounts presented as in-service additions. API expects there to be a level of "churn" whereby some of the project spending in WIP at the end of the prior year are put into service in the current year, while similar levels of the current year's spending may not be in-service by the end of the year. In recent years, one-time, multi year projects have had larger impacts on CWIP balances.

PSC-SEC-43

REFERENCE: 4-SEC-25b

a) Algoma states that 'the Test Year OM&A forecast in account 5095 includes a provision for the revenue requirement associated with agreements assumed to be capitalized in API's forecasts.' Please provide which program as listed in App 2-JC includes Account 5095.
b) Please confirm that this account includes the $767,909 forecast for 2025 Land Use Fees. If not, what is the amount included in account 5095 for Land Use Fees.
c) Please specify the breakdown of the $767,909 into OM&A and provision for revenue requirement.
d) Please explain why account 5095 includes a provision for revenue requirement, when this is already included as part of the revenue requirement calculated from capital.

API Response:

a) OEB 5095 is included in the Overhead Lines and Feeders program as outlined in 2-JC.
b) Confirmed.
c) $124,122 is provisioned for OMA and $643,787 is provisioned for revenue requirement. API notes that some of the costs included in 5095 represent the budget for existing arrangements/commitments (ie: the entire amount does not represent the uncertain future agreements).

d) The amounts included in 5095 represent the ongoing commitments for expensed payments and related costs which API has already entered into, as well as the revenue requirement equivalent of any <u>new</u> land use fees still to be negotiated, which may ultimately take the form of capitalized *or* expensed payments. These items are separate and incremental to the land use one-time payments/easements and associated costs previously entered into.

PSC-SEC-44

REFERENCE: 4-SEC-22 a), 4-SEC-28 e)

a) 4-SEC-22 a) Table 2-K shows that there are 68 FTEs at the end of June 2024. 4-SEC-28 e) notes that the seasonal workers and co-student have been hired and in addition, two PLT positions that were temporarily vacant in 2023 have been filled. Please provide a list of which positions are vacant (or allocations not provided) and indicate if Algoma expects to fill them by year end.

API Response:

See table below.

Position Vacant as of June 30, 2024	**Date Filled**
Distribution Technician	July 2, 2024
Customer Service Agent	August 26, 2024
Powerline Technician	July 29, 2024
Utility Arborist	Vacant - Currently Recruiting
Electrical/Meter Technician	July 29,2024

Please note that for any of the new hires in 2024 included in 4-SEC-22, including seasonal employees hired partly through the year, the FTE calculation was annualized by taking the relative number of months worked YTD (to end of June) and then multiplying by a factor of 2. For example, a seasonal labourer brought on board in April 2024, would have translated to an FTE of 0.7 in 4-SEC-22 (2 months working / 6 months Jun YTD * 2). This approach was intended to then be a like-for-like comparison against the YTD 2-K dollars also noted in 4-SEC-22.

ALGOMA POWER INC. (API)
2025 RATE APPLICATION (EB-2024-0007)
PRE-SETTLEMENT FOLLOW-UP AND CLARIFICATION QUESTIONS

(Numbering follows from VECC IR numbering)

PSC-VECC-46

REFERENCE: 3-Staff 33 b)
Load Forecast, Rate Class Customer Model Tab

a) Please explain why the 2014-2023 geomean growth rates set out in Staff 33 b) don’t match those calculated in the Load Forecast Model, Rate Class Customer Model Tab, Row 33.

API Response:

The geomean growth rates presented in Row 33 of the load forecast model represent the geomean growth in 2015-2023 (9 years of growth rates), while those in the response to 3-Staff-33 represent the growth rates in 2014-2023 (10 years of growth rates).

PSC-VECC-47

REFERENCE: 3-VECC 20
Exhibit 3, page 20

a) Exhibit 3 (page 20) indicates that the addition of the DLI customers occurred in 2020. However, VECC 20 indicates that the change happened in August 2019. Please reconcile.

API Response:
Consistent with the Letter sent by API in EB-2018-0271, the DLI transaction closing date was August 1, 2019.

Despite this, API confirms that the increase in DLI customers was reflected in the 2020 customer numbers used in the Load Forecast, not 2019.

PSC-VECC-48

REFERENCE: 7-VECC 36 b)

a) The original question asked about the number of Residential customers owning their transformers vs. the number owning the secondary assets serving them. The response does not address the question but rather the location of the meter. Please respond to the question as originally posed.

API Response:

API confirms there are 9 customers in the Residential R1 class who own their own transformers. Of these customers, all customers own the secondary assets. Three of the nine customers are secondary metered, but these three customers still own their secondary assets.

PSC-VECC-49

REFERENCE: 1.0-VECC-1

Please explain the variances in each project component of the #4 Circuit Project (System Access,2023) and provide any internal variance reports that explain the variances.

API Response:

Item		Project Component	Total Estimated Cost (excl. HST)	Actual Costs
1	a	Construction General Costs	$ 483,593	$ 914,518
	b	Line EPC (Excl. Water Crossing)	**$ 6,781,062**	**$ 4,501,815**
	c	Line EPC (Water Crossing)	**$ 240,268**	**$ 2,756,940**
	d	Premium	$ 93,571	$ 653,851
2		Project Management and Studies	$ 900,781	$ 1,617,904
3		Land	$ 115,592	$ 788,451
		Subtotal	$ 8,614,867	**$ 11,233,479**
		Contingency (15% of Subtotal)	$ 1,292,230	$ -
		Total	**$ 9,907,097**	**$ 11,233,479**

Item 1 (a, b, c, d) – Project EPC (Engineering, Procurement, & Construction) Cost

Due to the complexity of the project, API hired a consulting firm to perform the project EPC cost estimate, which provided the basis for determining the relevant components' estimated costs in the OTC.

API then secured two contractors via the tender process; one was for the "Engineering Design", and one was for the "Procurement & Construction".

As the table shows, the total actual cost for Item-1 is $ 8,827,124, while the total estimated cost for Item-1 is $8,738,268 (with the 15% contingency). Although the total amount variance is very small, the allocation among the four sub-components a, b, c, d had been significantly changed.

The non-water-crossing EPC portion (**Item 1-b**) was much lower than the estimate, while the water-crossing EPC (**Item 1-c**) was much higher than the estimate. Due to the constraint on the land right (see explanation below for Item 3), the engineering design Contractor was not permitted to perform the field geo-technical study before the construction, which was a prerequisite for the water crossing foundation & structure design. As a result, the design API provided to the construction bidders was not the finalized design during the tender process, with basic assumptions included so all bidders could bid on it. Another component that was excluded from the scope of water crossing construction was the "access road". All bidders claimed it was too hard to include the access road in their proposal given the uncertainties regarding land rights and geo-condition assessment.

During the construction, multiple change orders were submitted from the EPC contractors due to the poor geo-technical conditions for the water crossing. The escalated design complexity triggered a series of time sensitive activities, ranging from material procurement (caisson, RS poles and associated hardware, etc.) to mobilizing more subcontractors on site to perform tasks (testing, helicopter installation, civil construction, etc.) that was not in the original scope of work of the contractors. A new access road was built so the contractors and their sub-contractors can mobilize the crew and heavy equipment on site. That is why **Item 1-a** was significantly higher than expected.

Per customer request for future expansion considerations, i.e., although the project only built one circuit, the structures and framings were prepared in order to accommodate a 2nd circuit. **Item 1-d** ("Premium") relates to, the incremental design costs due to this consideration. With the escalated complexity of water crossing design and build (already difficult to design/build for one circuit), the engineering Contractor made a significate extra effort so the two long-span water crossings can accommodate the 2nd circuits in the future. As a result, Item 1-d was higher than the estimated.

Item 2 – Pre-construction Expenses and Project Management during construction

Item 2 contains the costs for pre-construction activities (studies, tender preparation, OTC development, 3rd-party cost estimate, external legal support), and the project management during the construction. API hired a 3rd party consulting firm as the "Owner Engineer" during the construction. This Contractor was responsible for coordinating among contractors and managing the progress, invoices, change orders, and the quality assurance and quality control (QA/QC). This Contractor secured a local subcontractor to perform the field inspection on a regular basis. Given the escalated complexity of the water crossing construction, this Contractor submitted change orders for involving more subcontractors on QA/QC and field inspection. The variance was also incurred from the extended duration of the project.

Item 3 – Land Right acquisition, negotiation, and First Nation "Duty to Consult"

In the original project, there was a request by one customer to relocate line out of their property, introducing the complexity of new right of way, land use and water crossing permits. The complexity and associated fees for the "Land" component were unknown in the original estimate and based on some internal historical estimates. Also, during the process of applying for provincial permits, API was delegated the Duty to Consult by the Ministry of Natural Resources and Forestry. API hired a 3rd party engineering firm to perform the specific cultural and environmental assessments during the engagements with local First Nations. Also, given the additional complexities of the engagements, API utilized the support of legal resources to ensure permits were issued and land rights secured. This included the negotiations with various landowners, consultations with First Nations and their representatives, and development of all formal agreements and documents. The geotechnical-investigation and land surveyor services were also higher than expected, however the overall variance is mainly due to the environmental assessment and legal expenses.

PSC-VECC-50

REFERENCE: 2-VECC 7 Part (b)
Exhibit 2, Attachment 2A, DSP Page 116

VECC requested final project cost variance reports to explain the variances for the following projects: Distribution Line Rebuilds, Dubreuilville Station Rebuild and Bruce Mines DS Rebuild. Please provide any internal documentation that explains the variances.

API Response:

Algoma Power has included a breakdown of the cost driver variances for the Distribution Line Rebuilds, Dubreuilville Station Rebuild and Bruce Mines DS Rebuild in response to 2-VECC-7 (c), (d) and (e) respectively. Further details of these cost variances are explained in Section 5.4.1.1.2 of the DSP.

PSC-VECC-51

REFERENCE: 4-VECC 29 Part (b) & (c)

a) Please explain the increase in contractor costs for Brush Control in 2025.

The provision for 2025 Brush Control is based on a total of 190km. Of these 190 km, API has already received multiple quotes for 135km of the work (associated with an average complexity of 3.81), with the lowest bids representing an average cost per km of [redacted] based on contractor pricing.

A component of the work, 55 km, has a “very high” complexity/density of 6.0, and has not yet been quoted. API has forecasted a cost of $[redacted]/ km for these areas in light of the relative complexity (the highest on the scale).

	$ Costs	Avg Cost/km	km		Avg Complexity
2023 Actual	**$ 385,869**	**$ 5,936**	**65**		**4.38**
2025 -Lowest Quote	[redacted]	[redacted]	135		3.81
2025- Not Yet Quoted	[redacted]	[redacted]	55		6.00
2025 Total	**$ 1,311,266**	**$ 6,901.4**	**190**		**4.45**

Ontario Energy Board (OEB) Staff's Pre-Settlement Clarification Questions
2025 Electricity Distribution Rates Application
Algoma Power Inc. (Algoma Power
EB-2024-0007
September 13, 2024

PSC-Staff- 1
Ref 1: IRR, Part 1, p.7 Preamble
Ref 2: 2-SEC-18e IRR

Preamble:
In reference 1, Algoma Power noted the potential of selling assets for the #4 circuit project to an industrial customer that is currently connected to the distribution line assets.

Question(s):

a) Would Algoma Power be willing to treat the entirety of the #4 circuit project or a portion of the project outside of rate base similar to that of ACM treatment?
b) At 2-SEC-18e, SEC asked about any capital contributions received for the new construction portion of the project. Algoma Power responded that a capital contribution of $3.5M was received. Please confirm that this contribution is for the new construction portion of the line and not the replacement credit. If so, where is this contribution found in the Chapter Appendices, 2-AA?

API Response:

a) API believes it would be most appropriate to treat the sale of line C-E on an isolated basis from the remainder of the project, partly for the purpose of addressing the "replacement/advancement credit issue" in order to avoid undue delays in the refund of the "replacement credit" deposit that is potentially owed to the connecting customer(s).

   ACM/ICM treatment is not API's preferred/recommended approach. To API's understanding, the ACM/ICM process is intended for future forecasted projects, the cost of which are not yet known. API does not believe the circumstances around the #4 Circuit project match the intended use from this perspective, since the #4 Circuit project is now complete and energized and costs are known. Additionally, a materiality threshold applies to ACM/ICM projects which API does not believe would be appropriate, since the project costs are known as of the 2025 test year and API believes the associated costs should be fully eligible for rate base addition.

API would be open to discussing potential regulatory treatments for the applicable portion of this project at the Settlement Conference.

b) API confirms that the capital contribution recorded for the #4 circuit project is not associated with the portions of the project that are subject to the replacement credit. The capital contribution is included with the system access capital contributions in the 2024 Bridge Year.

PSC-Staff- 2
Ref 1: 2-Staff-5 2-AA IRR

Preamble:
In reference 1, Algoma Power provided spending to June for 2024. Algoma Power spent $2.1M of its $5.5M budget (38%) on distribution pole line rebuilds and $49k of its $2.0M budget (2%) on subtransmission line rebuilds as of the end of June.

Question(s):

a) Please confirm whether Algoma Power still believes it can meet its original budget for these two programs in 2024.
b) What are the drawbacks of reducing the budget in these two programs closer to historical spending levels (2020-2023) of $3.7M and $129k respectively?

API Response:

A) Yes, Algoma Power believes it will meet its original budget for these two programs in 2024. The noted total budget spend is based on the total forecasted in-service additions in 2024, which includes assets in WIP and Capital Expenditures going into service. The spending to date only reflects capital expenditures to date and doesn't reflect the total in-service additions to date. Spending to June for 2024 is based on capital expenditures to date. The total in-service additions are higher based on WIP assets going into service from previous years. To date at the end of August, API's total in-service additions for its rebuild programs is $4.1M for Distribution Line Rebuilds, and $1.0M for Subtransmission Line Rebuilds
B) Reducing the budgets in these two programs will mean that less poles willbe replaced annually. As described in Section 5.4.2.4.2.2 and 5.4.2.4.2.3 of the DSP, decreasing the annual pole replacement targets would result in an increasing risk associated with high-risk in-service poles. This could quickly lead to a cycle where the increasing reactive replacement costs due to more frequent unexpected pole failures and a greater number of deficiencies identified during patrols lead to less budget room available for the proactive replacement, which further decreases the annual number of poles replaced proactively. Furthermore, this reduction would add risk associated with increased upward pressure on API's OM&A.

   Reducing the Subtransmission line rebuilds to $129k annually will only allow API to replace about 11-13 poles each year. With such a small annual replacement target, API would need to be significantly more selective and targeted, and as a result the poles replaced would be more sporadic throughout the service territory. This would increase the overall mobilization cost, which in turn would increase the replacement cost per pole. The reduction in replaced poles under this program will also increase the risk of reactive pole failures, which are costlier and more impactful to the reliability of the API's distribution system.

PSC-Staff- 3
Ref 1: 2-Staff-22 IRR

Preamble:
In reference 1, Algoma Power provided a list of vehicles being replaced in 2024 and 2025 and the vehicles being acquired. Six vehicles are being replaced in 2024 yet Algoma Power is purchasing seven vehicles.

Question(s):

a) Please provide the need for the additional vehicle or note whether this is an additional vehicle replacement from a previous year.

API Response:

Algoma Power acquired an additional light duty fleet vehicle in 2024 so that it could discontinue the cost of renting one. Historically, Algoma Power had an annual rental vehicle for contract monitoring.

PSC-Staff-4
Ref 1: 2-Staff-7d IRR

Preamble:
In reference 1, Algoma Power notes that its goal is to replace 2,500 poles over the forecast period (400 per year in the Distribution Line Rebuild program and 100 per year in the Subtransmission Line Rebuild program). Algoma Power noted that it considers several factors when replacing poles including condition, pole height, working clearances, mechanical loading and customer or third-party requirements.

Question(s):

a) Please provide the calculation or rationale in determining the replacement plan of 2,500 poles over five years across the two programs.
b) Why does Algoma Power not adjust its replacement plan given replacements in other programs, such as due to customer/third-party requests?

API Response:

a) The annual target planned replacement rate of 500 poles per year is based on approximately 2% of the pole population. This is intended to replace the majority of poles prior to in-service failure or remaining strength that is below relevant CSA specifications. This also ensures that the associated components (insulators, hardware, crossarms, grounding, guying, etc.) remain intact without major issues for the lifecycle of each pole.
b) Algoma Power follows its asset management practices as described in Section 5.3.1.3 of the DSP. Customer/Stakeholder requests are a consideration in its project/program planning process. However, given the discretionary nature of these requests, Algoma Power does not make pre-emptive adjustments to its replacement strategy.

PSC-Staff- 5
Ref 1: 2-Staff-27 IRR
Ref 2: 2-Staff-10d IRR

Preamble:
Per reference 1, Algoma Power is spending $319k on the 34.5kV Switching Automation project. Per reference 2, Algoma Power states that the 34.5kV switches will result in reduced overall outage impacts even during major events.

Questions:

a) Please explain how the 34.5 kV switching automation project is expected to reduce outage times for the most common extended outage causes, e.g., vegetation contact and more specifically trees or branches falling on lines. Please provide an illustrative example of an outage duration which would be materially reduced following the installation of the new devices.

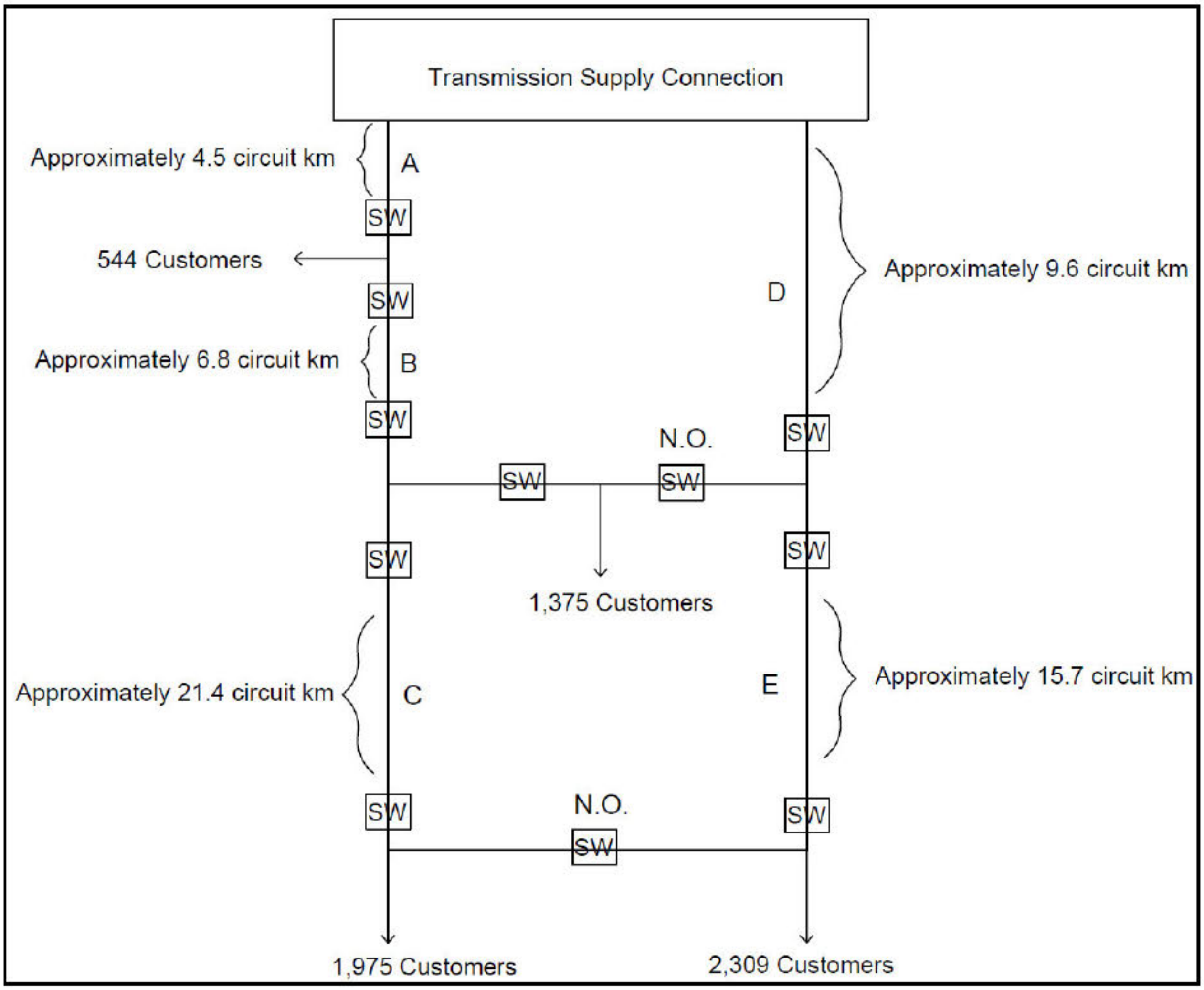
API Response:

The 34.5kV switching automation project consist of deploying a distribution automation (DA) scheme on a section of Algoma Power's 34.5kV East of Sault Ste Marie subtransmission circuits. The DA scheme will be based on the FLISR functionality (Fault Location, Isolation and Service Restoration).

In order to provide an illustrative example, please refer to the simplified diagram of API's 34.5kV East of Sault Ste Marie Subtransmission circuits.

	Without the 34.5kV Switching Automation	With the 34.5kV Switching Automation
Fault Section	E	
Impacted Section	D&E	D&E
Total Customers Initially Out	2,309	2,309
Restoration Steps	Field crews mobilize to site to locate faulted section.	The intelligent automated devices detect and identify the faulted section.

	Perform necessary manual switching to isolate the faulted section Restore power the customer using normally open (N.O.) device	Automated switching operation is performed to isolate the faulted section. Once the faulted section is isolated, power is restored automatically using normally open (N.O.) intelligent automated device.
Restoration timeline	2 – 4 hours	<1 minute



PSC-Staff- 6
Ref: 2-SEC-12

Preamble:
Algoma Power provided variance table in their responses to question 2-VECC-7, e) with regards to the Bruce Mines DS Rebuild project.

Questions:

a) With reference to the Bruce Mines DS Rebuild, was the variance largely (or entirely) due to covid pandemic cost escalation of labour, equipment and material?
   i. If yes, please separately estimate the % variance from the budget estimate on labour, equipment and material costs directly attributable to the covid pandemic.
   ii. If no, please identify all causes of variance and the resulting % variance attributable to each of the identified causes on labour, equipment and material costs.

API Response:

A) The % variance from the budget is largely due to contractor pricing, and material price escalation. Algoma Power cannot identify the causes for contractor increase, but did seek competitive pricing through competitive bids. In 2-Sec-12, Algoma Power indicated that the increase was mainly due to rising costs of material and labour. The labour was in reference to contract labour.

PSC-Staff-7
Ref 1: 4-Staff-47

Preamble:
Algoma Power notes CNPI hired a dedicated legal counsel and that it is planning on adding an articling student to be hired in 2025.

a) Please provide the business case for these two positions.
b) Please explain what legal fees will be offset due to the direct allocation of 25% and 28% for these two FTEs to Algoma Power.

API Response:

a) As background, CNPI hired an in-house Legal Counsel position in 2017. Prior to 2017, CNPI was served by a General Counsel position since around 2003. As a result, there is no recent business case. Nonetheless, legal matters can be managed with either the use of internal or external legal resources. The use of external legal resources is significantly more expensive than internal resources. At a high level, using external legal counsel opposed to internal legal counsel increases legal costs per hour by an estimated range of approximately 600% to 1,600%. With respect to efficiency, external resources may also be less familiar with our organization and the industry. Our approach in managing legal matters is guided by ensuring efficiency, cost sensitivity, and quality of legal services. Accordingly, our approach is to first utilize internal legal resources, unless it requires a subject matter expert, or there is no capacity to complete the work.

b) With more legal work arising in both quantity and complexity, we are having to use external counsel more regularly, which we aim to try and minimize. Hence, an additional internal legal resource, such as an articling student for a temporary term, will help directly or indirectly offset work that would otherwise be sent to external legal counsel, including, general legal services, litigation and dispute resolution, compliance, contract and procurement, governance and policies, major projects and project management support, and corporate secretariat.

PSC-Staff-8
Ref 1: 4-Staff-48

Questions:

a) Please explain the differences between the following accounts and confirm if all of these accounts are needed:

i. Account 1508 – Other Regulatory Assets – Pension Expense Variance Sub-Account
- record the difference between pension expense under Section 3461 and Section 3462

ii. Account 1508 – Other Regulatory Assets – Amortized Pension Actuarial Gains/Losses
- record the amortized pension actuarial gains/losses under S3461

iii. Account 1508 – Other Regulatory Assets – OPEB Expense Variance Sub-Account
- record the difference between OPEB expense under Section 3461 and Section 3462

iv. 1508 – Other Regulatory Assets – Amortized OPEB Actuarial Gains/Losses
- record the amortized OPEB actuarial gains/losses under S3461

b) Please explain the nature of the above four accounts respectively (i.e. tracking account or account that Algoma intends to request for the disposition in its cost of service applications in the future).

API Response:

a) API confirms that all accounts are needed.

- Account 1508 – Other Regulatory Assets – Pension Expense Variance Sub-Account. Per EB-2013-0368/EB-2013-0369, this sub-account is being used to record the difference between pension expense under Section 3461 and Section 3462, starting January 1, 2013.
- Account 1508 – Other Regulatory Assets – Amortized Pension Actuarial Gains/Losses. In accordance with the Settlement proposal withing EB-2019-0019, this account has been used by API to record the amortized pension actuarial gains/losses under S3461 pension and accounting standard.
- Account 1508 – Other Regulatory Assets – OPEB Expense Variance Sub-Account. Per EB-2013-0368/EB-2013-0369, this sub-account is being used to

record the difference between OPEB pension expense under Section 3461 and Section 3462, starting January 1, 2013.

- 1508 – Other Regulatory Assets – Amortized OPEB Actuarial Gains/Losses. In accordance with the Settlement proposal withing EB-2019-0019, this account has been used by API to record the amortized OPEB actuarial gains/losses under Section 3461 pension and accounting standard.

b) API is not requesting disposition of the balance of the following sub-accounts in this proceeding:

Account 1508 – Other Regulatory Assets – Pension Expense Variance Sub-Account; and

Account 1508 – Other Regulatory Assets – OPEB Expense Variance Sub-Account.

API is requesting disposition of the balances of the following sub-accounts in this proceeding:

Account 1508 – Other Regulatory Assets – Amortized Pension Actuarial Gains/Losses ($226,148 in Table 9-1); and

Account 1508 – Other Regulatory Assets – Amortized OPEB Actuarial Gains/Losses ($258,334 in Table 9-1)

PSC-Staff- 9
Ref 1: 6-Staff-53

Question(s):

a) Please describe the accounting treatment for revenues collected for Algoma Power's R1 and R2 rate classes vs. Seasonal and Streetlighting customers.

API Response:

Both rate riders collected for seasonal and streetlighting along with all amounts received through RRRP funding (Residential R1 and R2 classes) have been recorded in DVA 1508 sub-accounts accounts and have been included in the DVA continuity schedule within both "Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues - Sault Building" and "Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues - Echo River."

PSC-Staff- 10
Ref 1: 6-Staff-57

Question(s):

a) Please confirm the additions subject to enhanced CCA, as provided in the 1592 PILs DVA calculation, are consistent with the actual tax filings for 2018 and 2019.

API Response:

a) Confirmed.

PSC-Staff- 11
Ref 1: 9-Staff-68
Ref 2: Chapter 2 Appendices, September 4, 2024
Ref 3: Exhibit 9, Table 9-10

Preambles
In Reference 1, an addition of $15,237,022 is reported under Class 47, Account 1808, Buildings – Fixtures, based on the actual project spending for the SSM Facility ACM. However, in Reference 2, this addition is reported under Class 1, Account 1908, Building & Fixtures.

Question(s):
a) Please confirm the correct CCA class and Account under which this addition should be reported.
b) Please update the Chapter 2 Appendices and Table 9-10, 1592 PILs Calculation for SSM Facility ACM Project in Reference 3 as applicable.

API Response:

a) The $15,237,022 should be reported under OEB 1908 and CCA Class 1.3. Below is the updated labelling for the tables provided in 9-Staff-68 part b).
Actual Project Spending

Year 2022 MIFRS

			Cost				Accumulated Depreciation				
Class	OEB	Description	Balance	Additions	Disposals	Balance	Balance	Additions	Disposals	Balance	Net Book Value
47	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ 713	$ -	713	$ -	-$ 2	$ -	-2	711
N/A	1805	Land	$ -	$ 865,341	$ -	865,341	$ -	$ -	$ -	0	865,341
1.3	1908	Buildings & Fixtures-50 Yrs	$ -	$ 14,696,796	$ -	14,696,796	$ -	-$ 24,154	$ -	-24,154	14,672,642
1.3	1908A	Buildings & Fixtures-25Yrs	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1915	Office Furniture & Equipment (10 years)	$ -	$ 8,991	$ -	8,991	$ -	-$ 75	$ -	-75	8,916
50	1920	Computer Equipment - Hardware	$ -	$ 220,574	$ -	220,574	$ -	-$ 3,676	$ -	-3,676	216,898
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ -	$ 21,304	$ -	21,304	$ -	-$ 179	$ -	-179	21,125
		Sub-Total	**0**	**15,813,719**	**0**	**15,813,719**	**0**	**-28,086**	**0**	**-28,086**	**15,785,633**

Year 2023 MIFRS

			Cost				Accumulated Depreciation				
Class	OEB	Description	Balance	Additions	Disposals	Balance	Balance	Additions	Disposals	Balance	Net Book Value
47	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 713	$ -	$ -	713	-$ 2	-$ 18	$ -	-20	693
N/A	1805	Land	$ 865,341	$ -	$ -	865,341	$ -	$ -	$ -	0	865,341
1.3	1908	Buildings & Fixtures-50 Yrs	$ 14,696,796	$ 540,226	$ -	15,237,022	-$ 24,154	-$ 294,173	$ -	-318,327	14,918,695
1.3	1908A	Buildings & Fixtures-25Yrs	$ -	$ 10,745	$ -	10,745	$ -	$ -	$ -	0	10,745
8	1915	Office Furniture & Equipment (10 years)	$ 8,991	$ -	$ -	8,991	-$ 75	-$ 899	$ -	-974	8,017
50	1920	Computer Equipment - Hardware	$ 220,574	$ -	$ -	220,574	-$ 3,676	-$ 44,114	$ -	-47,790	172,784
10	1935	Stores Equipment	$ -	$ 55,244	$ -	55,244	$ -	-$ 4,604	$ -	-4,604	50,640
8	1960	Miscellaneous Equipment - 10 yr	$ 21,304	$ 34,107	$ -	55,411	-$ 179	-$ 2,131	$ -	-2,310	53,101
		Sub-Total	**15,813,719**	**640,322**	**0**	**16,454,041**	**-28,086**	**-345,939**	**0**	**-374,025**	**16,080,016**

Year 2024 MIFRS

			Cost				Accumulated Depreciation				
Class	OEB	Description	Balance	Additions	Disposals	Balance	Balance	Additions	Disposals	Balance	Net Book Value
47	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 713	$ -	$ -	713	-$ 20	-$ 18	$ -	-38	675
N/A	1805	Land	$ 865,341	$ 200,622	$ -	1,065,963	$ -	$ -	$ -	0	1,065,963
1.3	1908	Buildings & Fixtures-50 Yrs	$ 15,237,022	$ -	$ -	15,237,022	-$ 318,327	-$ 304,748	$ -	-623,075	14,613,947
1.3	1908A	Buildings & Fixtures-25Yrs	$ 10,745	$ -	$ -	10,745	$ -	-$ 430	$ -	-430	10,315
8	1915	Office Furniture & Equipment (10 years)	$ 8,991	$ -	$ -	8,991	-$ 974	-$ 899	$ -	-1,873	7,118
50	1920	Computer Equipment - Hardware	$ 220,574	$ -	$ -	220,574	-$ 47,790	-$ 44,115	$ -	-91,905	128,669
10	1935	Stores Equipment	$ 55,244	$ -	$ -	55,244	-$ 4,604	-$ 5,525	$ -	-10,129	45,115
8	1960	Miscellaneous Equipment - 10 yr	$ 55,411	$ -	$ -	55,411	-$ 2,310	-$ 5,542	$ -	-7,852	47,559
		Sub-Total	**16,454,041**	**200,622**	**0**	**16,654,663**	**-374,025**	**-361,277**	**0**	**-735,302**	**15,919,361**

Capped Project Spending

Year 2022 MIFRS

			Cost				Accumulated Depreciation				
Class	OEB	Description	Balance	Additions	Disposals	Balance	Balance	Additions	Disposals	Balance	Net Book Value
47	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ 576	$ -	576	$ -	-$ 1	$ -	-1	574
N/A	1805	Land	$ -	$ 699,045	$ -	699,045	$ -	$ -	$ -	0	699,045
1.3	1908	Buildings & Fixtures-50 Yrs	$ -	$ 11,872,458	$ -	11,872,458	$ -	-$ 19,787	$ -	-19,787	11,852,670
1.3	1908A	Buildings & Fixtures-25Yrs	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1915	Office Furniture & Equipment (10 years)	$ -	$ 7,263	$ -	7,263	$ -	-$ 61	$ -	-61	7,203
50	1920	Computer Equipment - Hardware	$ -	$ 93,449	$ -	93,449	$ -	-$ 1,557	$ -	-1,557	91,891
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ -	$ 17,210	$ -	17,210	$ -	-$ 143	$ -	-143	17,066
		Sub-Total	**0**	**12,690,000**	**0**	**12,690,000**	**0**	**-21,550**	**0**	**-21,550**	**12,668,450**

Year 2023 MIFRS

			Cost				Accumulated Depreciation				
Class	OEB	Description	Balance	Additions	Disposals	Balance	Balance	Additions	Disposals	Balance	Net Book Value
47	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 576	$ -	$ -	576	-$ 1	-$ 14	$ -	-16	560
N/A	1805	Land	$ 699,045	$ -	$ -	699,045	$ -	$ -	$ -	0	699,045
1.3	1908	Buildings & Fixtures-50 Yrs	$ 11,872,458	$ -	$ -	11,872,458	-$ 19,787	-$ 237,449	$ -	-257,237	11,615,221
1.3	1908A	Buildings & Fixtures-25Yrs	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1915	Office Furniture & Equipment (10 years)	$ 7,263	$ -	$ -	7,263	-$ 61	-$ 726	$ -	-787	6,476
50	1920	Computer Equipment - Hardware	$ 93,449	$ -	$ -	93,449	-$ 1,557	-$ 18,690	$ -	-20,247	73,202
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ 17,210	$ -	$ -	17,210	-$ 143	-$ 1,721	$ -	-1,864	15,345
		Sub-Total	**12,690,000**	**0**	**0**	**12,690,000**	**-21,550**	**-258,601**	**0**	**-280,151**	**12,409,849**

Year 2024 MIFRS

			Cost				Accumulated Depreciation				
Class	OEB	Description	Balance	Additions	Disposals	Balance	Balance	Additions	Disposals	Balance	Net Book Value
47	1612	Land Rights (Formally known as Account 1906 and 1806)	$ 576	$ -	$ -	576	-$ 16	-$ 14	$ -	-30	546
N/A	1805	Land	$ 699,045	$ -	$ -	699,045	$ -	$ -	$ -	0	699,045
1.3	1908	Buildings & Fixtures-50 Yrs	$ 11,872,458	$ -	$ -	11,872,458	-$ 257,237	-$ 237,449	$ -	-494,686	11,377,772
1.3	1908A	Buildings & Fixtures-25Yrs	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1915	Office Furniture & Equipment (10 years)	$ 7,263	$ -	$ -	7,263	-$ 787	-$ 726	$ -	-1,513	5,750
50	1920	Computer Equipment - Hardware	$ 93,449	$ -	$ -	93,449	-$ 20,247	-$ 18,690	$ -	-38,937	54,512
10	1935	Stores Equipment	$ -	$ -	$ -	0	$ -	$ -	$ -	0	0
8	1960	Miscellaneous Equipment - 10 yr	$ 17,210	$ -	$ -	17,210	-$ 1,864	-$ 1,721	$ -	-3,585	13,624
		Sub-Total	**12,690,000**	**0**	**0**	**12,690,000**	**-280,151**	**-258,601**	**0**	**-538,751**	**12,151,249**

b) One minor change made to Chapter 2 Appendices in Reference 2 (1808A to 1908A). No change required to Table 9-10, 1592 PILs Calculation for SSM Facility ACM Project in Reference 3.

PSC-Staff- 12
Ref 1: 9-Staff-75

Preambles
Algoma Power states that "excluding the Land Use baseline from base rates means exclusion from RRRP and DRP funding, resulting in a long-term net bill increase to API's RRRP and DRP eligible customers."

Question(s):
a) Please quantify the impact on the RRRP and DRP funding resulting from the exclusion of the Land Use baseline from base rates.

API Response:

There is no impact to DRP funding because the RRRP adjustment will continue to cap the distribution rate at the same levels.
The impact to RRRP funding is a decrease of $690,442.52.

	1-Staff-1	Remove LU Baseline	Difference
Residential R1 (i)			
Residential R1 (ii)	$ 22,980,449.00	22,469,307	-$ 511,142.36
Residential R2	$ 8,044,220.00	7,864,920	-$ 179,300.16
Total	$ 31,024,669.00	30,334,226	-$ 690,442.52
Funding Through RRRP adj Rates	$ 10,334,091.92	$ 10,334,091.92	$ -
RRRP Funding Requirement	**$ 20,690,577.08**	**$ 20,000,134.56**	**-$ 690,442.52**
Seasonal	$ 3,405,520.00	3,328,536	-$ 76,983.70
Street Light	$ 231,700.00	226,535	-$ 5,164.73
Base Revenue Requirement	$ 34,661,889.00	$ 33,889,298.05	-$ 772,590.95
Variance from 767 909 due to OM&A Impact on Rate Base (via WCA)			-$ 4,681.95

PSC-Staff- 13

Ref 1: 2-Staff-15b

Ref 2: 2-SEC-13 IRR

Preamble:

In reference 1, Algoma Power noted that they are expecting 400-600 pole replacements due to broadband projects in 2024-2025. In reference 2, Algoma Power stated that it has not included any amounts in account 1508 for broadband projects.

Question(s):

a) Please explain how Algoma Power is bringing the 400-600 broadband pole replacements into rates.

API Response:

For 2024 and 2025, API intends to continue to make entries into the Broadband variance account. Designated broadband projects, for the most part, are expected to be placed into service in 2025 due to the timelines of the funding programs for the telecommunications companies involved.

API extrapolated the expected quantity based on the permits that have been reviewed thus far. API has insufficient information regarding the locations of the work to be completed with respect to Broadband proposals, and therefore cannot estimate with accuracy the total quantity of replacement and the associated level of costs to be incurred in these years.

PSC-Staff- 14

Please confirm the following:

- Total cost of the line, replacement credit, net cost of line, and confirm that the total cost of line is for the $11,233,479, is for the 11.2 km; that was reduced by the replacement credit, is the number used in the economic evaluation which resulted in the contribution of $3,461,610 dollars

API Response:

Please see the table below:

	$Value	km	
Overall Project	$ 11,233,479	11.2	
Replacement Component	$ 3,468,826.00	9.2	this is the replacement cost for this 9.2 km,however other costs related to this area were also incurred (ex: water crossing).
Non- Replacement Component	$ 7,764,653.00	N/A	
Capital Contribution	$ 3,461,610.00	N/A	
Net Cost	$ 7,771,869.00	N/A	

Settlement Proposal – Pre-Settlement Clarification Questions-SEC 39-Hydro One Response

Algoma Power Inc.
EB-2024-0007

General Questions:

1. In terms of overall budget, API has noted a discrepancy between the allocation of the updated budget of $10.5M among cost components (see right-most column above) versus the forecasts in the quarterly project status reports. Please provide further details addressing the discrepancy and final cost.

   The overall discrepancy (variance between Q1 2023 Forecast and the Notices) pointed out is $2,230.88. Please note that both the Q1 2023 Forecast and Notices are forecasted values only, the actual (final) costs are yet to be billed.

2. Further, API requests an outline of the original budget and forecast update between internal and external costs. Has the split among these categories changed since the initial project budget?

   ~~If this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.~~

   - **The split has only slightly changed with Hydro One's percentage increasing:**
     - **Original Breakdown (% of overall project cost):**
       - **Hydro One – 31%**
       - **API – 69%**
     - **New Breakdown (% of overall project cost):**
       - **Hydro One - 33%**
       - **API – 67%**

Engineering: +$285k:

3. The engineering budget inclusive of both external consulting and internal staff time? What is the breakdown between these categories and any other categories?

   ~~If this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.~~

   - **The engineering budget includes internal staff time and external consulting for Geotechnical Studies. The breakdown is the following:**
     - **External – 16%**
     - **Internal – 84%**

Grounding study identified more deficiencies to be addressed, additional resources were required to address these deficiencies

4. Further explanation- as this is an existing TS.

   Any deficiencies with regards to the existing TS has been addressed and funded by Hydro One. On the customer portion of the project, incremental time and effort was required to resolve grounding issues that were encountered during detailed design – GPR, Touch and Step potential.

5. What budget impact did this have?

~~If this information is required by the regulator, Hydro One can directly provide this information to the regulator.~~

The total cost impact to address grounding deficiencies with the existing station is 3.0M and is broken down as follows:

- **Incremental engineering effort due to existing station challenges ($1.0M)**
- **Baseline quantity changes due to design maturity breakdown($1.8M):**
  - **Procurement: Material quantity additions to foundations, bus work & insulators, cable trench, oil water separator, structural steel, grounding, control material, station service equipment, power cable ($0.6M)**
  - **Construction: Manpower and hired equipment costs driven by material quantity additions to foundations, bus work & insulators, cable trench, grounding, station service, power cable (0.9M)**
  - **Project Management: Additional effort on scheduling, outage management, project coordination to manage overall changes ($0.3M)**
- **RFC engineering deliverable for Heating and Preservation for winter construction ($0.2M)**

Equipment vendor support and information such as shop drawings were slower than expected:

6. Please confirm whether this was internal or external to Hydro One?

Vendors being referred are external.

7. What efforts were made to mitigate the delays?

Regular meetings were held with the vendors to follow up and mitigate the delays to seek resolution.

8. Were there any premiums incurred to address delays?

~~If this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.~~

- **There were no premiums incurred to Hydro One by equipment vendors.**

Unexpected delay in transformer drawings and test reports held up completion of engineering, extending schedule and support required from resources

9. what is the basis for allocation of internal (HONI staff time)?

Internal staff time had to be allocated to meet with the vendors and review their design, seek resolution and drive outstanding issues to completion, additional engineering reviews/comments were required to ensure the proposed design was per standards.

10. Please describe the impact to schedule vs. and premium cost paid to address delays

A total of a 4-month delay was encountered during detailed design, which was mitigated by carrying out construction activities during the winter months.

Equipment And Materials +$700k:

11. API requests a breakdown of the original budget for each of the individual items below.

Item	Incremental Cost	Category
Oil-Water Separator Material	76,979	Equipment & Materials
Structural Materials	49,133	Equipment & Materials
Control Materials	136,840	Equipment & Materials
Bus, Hardware & Insulator Materials	96,325	Equipment & Materials
Switches Equipment	23,979	Equipment & Materials
Cable Trench Material	44,723	Equipment & Materials
Power Transformer Equipment	107,698	Equipment & Materials
Instrument Transformer Equipment	13,124	Equipment & Materials
Surge Protecting Devices	5,135	Equipment & Materials
Hired Equipment Electrical	131,291	Equipment & Materials
Civil Foundations Materials	13,760	Equipment & Materials

The original budget for Procurement (Equipment & Materials) was $2,060,000.

12. Additionally, API requests further information about the Power Transformer- what was the timing of the procurement, what are the specific delays and increases for the power transformer?

Overall, there was a 4-month delay in the procurement of the power transformer for reasons outlined in the engineering section. The order for this transformer was placed in July 2021 and it was delivered to site in October 2022. Initial budget for the power transformer was $1.3M and final cost was $1.4M.

Construction +$1.55M:
Given the order of magnitude increase in the construction budget, API requires further quantification of the contributing factors to this component

Delay in completion of IFC (Issue For Construction) engineering (as noted in the Engineering section) extended construction schedule into winter seasons, incurring additional heating & preservation expenses

12. Please quantify

~~If this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.~~

Construction activities that were executed during the winter months introduces additional preservation and heating costs of $0.2M.

Quotes received for Hired Equipment rentals - Crane, Scaffolding, Rock Drilling Rig, Generators are significantly higher than the 2020 estimate

14. Please quantify and explain HOSSM procurement process

Please find attached for Exhibit E-05-02 which details the Procurement Process and Warranty Claims process. This exhibit was part of Hydro One's Joint Rate Application.

Fuel costs are significantly higher for heating, temp power generators and other equipment noted above

15. Please quantify.

~~If this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.~~

- **The project cost estimate was completed in 2020, material and service cost increases have been significant in 2021 and 2022 which happened to coincide with the procurement phase of the project. Higher than estimated costs were encountered on construction sundries, power transformer, structural steel, hired equipment, switches, station service equipment and services due to updated labor cost assumptions. Cost increases attributed to material and service escalation cost a total of $1.2M. The fuel cost was $43,822.02.**

New soil management regulations introduced additional soil sampling and handling costs [Ontario Regulation 406/19 – filed December 4, 2019]

16. Please quantify. We understand the regulation to be effective January 1, 2023. Please confirm if the associated work occured after this date, or whether HOSSM has has advanced the requirements to apply in 2022.

HOSSM had applied the new soil management regulations to the whole project. It should be noted that construction for this project had occurred both in 2022 and 2023.

Incremental scope/quantities of material were added to address deficiencies (as noted in the Engineering section)

17. Please quanitfy.

Any deficiencies with regards to the existing TS has been captured under the Hydro One internal cost. Additions in this case (customer portion) refer to the initial estimate versus final quantities driven by detailed design. The following items had incremental quantities noted: foundations, bus work & insulators, cable trench, oil water separator, structural steel, grounding, control material, station service equipment, power cable.

Transformer delivery timeline is not optimal as IFC engineering delays resulted in a delayed construction start Requiring a temporary pad to be built to house the transformer until the transformer foundations are complete Additional craning and lifting costs are incurred as the transformer will have to be rigged into its permanent location from its temp pad

18. Please quantify. Did HONI consider speaking with API about delaying project?

API had been notified about this and acceptance was granted to proceed with the project. Hence, delaying the project was not a consideration.

Laydown area is now outside the compound, as space is required for transformer temporary pad inside compound, requiring additional areas to be prepared and maintained for material handling.

HOSSM also indicated that the construction increase [$1,548,945.88] included a portion due to internal rate increases [$330,033.38]

19. What is the basis for this adjustment? Is it wage increases? How many person-hours are associated with the project to result in such an increase?

This adjustment is driven based on labor rate (wage) increase.

Project Management +$68k:

20. API requests further information on the basis for this increase- what component is related to rates versus the amount of time allocated to the project? What are the major drivers?

Project management efforts are a function of all other aspects of the project. Incremental scope and effort required from other disciplines contributed to this project management increase.

"Third Notice" -Commissioning and Contingency net +$99k :

Commissioning team had to support heating and hoarding in the winter months, additional equipment, tools and transportation required to support transformer commissioning in winter which was not expected.

21. Please quantify and expand on this. As this is a project in Northern Ontario, I'm not sure why was this not expected?

Initial project schedule did not factor transformer commissioning during the winter months.

Vacuum pulling for the transformer was required for a much longer duration than estimated due to weather conditions and longer exposure time (vacuum pulling process being a continuous process it had a material impact).

22. Please provide additional details.
What was the planned vs actual schedule for the vacuum pulling? What were the weather conditions, when did they occur and how did they result in a material impact to the project?

~~If this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.~~

Originally, vacuum pulling was to take 36 hours and our vacuum pulling report showed that it took 82 hours. However, this was done erroneously as the 82 hours included oil filling efforts as well. The total time for vacuum pulling and oil filling is within the originally estimated tolerances and therefore this point is no longer considered as an issue.

Please find the planned vs. actual schedule below:

- **The planned schedule for vacuum pulling was 36 hours – Nov 17 – 21, 2022**
- **The actual schedule for vacuum pulling was: 36 hours, Jan 11 - 14, 2023**
- **Weather condition: The weather conditions were variable, with a highest of 10 C to the lowest of -22 C, and the average humidity of 83%**

There were issues with the 230 kV Circuit switcher that the commissioning team had to resolve, this item was shipped with the wrong parts, repairs had to be made onsite.

23. Please confirm who was responsible for incorrect shipment, HOSSM or the Manufacturer?

Incorrect shipment was the responsibility of the vendor. Replacement parts were furnished by the vendor at no additional cost, however, efforts on the field were required by construction and commissioning team to resolve this in a timely manner.

Unexpected outage delays caused by equipment failure at the neighboring Mississagi TS resulted in additional rental durations for equipment, crews were already onsite at Echo River TS for transformer soak and then the soak was rescheduled, this caused inefficiencies.

24. Please provide API a detailed report explaining the cause of the equipment failure and resource deployment for the Mississagi TS work.

~~If this information is required by the regulator to explain the cost variance, Hydro One can directly provide this information to the regulator.~~

- **Equipment Failure and Outage details.**
- **Summary:**
  - **Due to an open circuit arcing in a metering panel Hydro One Protection and Control team requested the immediate force from service of the AL23 breaker at Mississagi TS. The damage was caused to AL23 breaker and L23L26 cabling in the relay room. The unplanned outage to Mississagi TS equipment resulted in the loss of planned outages for the Echo River. Specifically, the outage needed to complete Live Zone Test Trip (LZTT) of the new T2 and equipment on**

May 11th, 2023. The Live Zone Test trip was required on May 11th on the P22G including all terminals to prove the new Echo River T2 protections ahead of putting it on potential for its 24-hour soak. On May 11th 2023, P22G, Echo River T1 and 34.5kv bus and feeders were required to be placed back in service.

- **Mississagi TS Outage Timelines:**
  - **Outage start date: May 03, 2023 – 12:21 pm**
  - **Outage end day: May 26, 2023 – 9:12 pm**

Settlement Proposal – Pre-Settlement Clarification Questions SEC-40-Promissory Note

Algoma Power Inc.
EB-2024-0007

ALGOMA POWER INC.

PROMISSORY NOTE

$12,750,000 **DUE: ON DEMAND**

FOR VALUE RECEIVED Algoma Power Inc. ("API") hereby promises to pay on demand to or to the order of FortisOntario Inc. ("FON") at 1130 Bertie Street, Fort Erie, Ontario, the principal amount of $12,750,000 in lawful money of Canada and to pay interest both before and after demand, default and judgement at the rate of 4.13% per annum, which interest rate will be automatically amended from time to time to be consistent with any interest rate approved by the Ontario Energy Board ("OEB") in connection with the then current decision and order issued by the OEB approving the electricity distribution rates that API is permitted to recover. The interest rate will be calculated monthly not in advance on the principal amount, said interest to be payable monthly in each year, commencing on the 1st day of January, 2019.

The principal amount outstanding under this promissory note from time to time and all accrued interest thereon shall become due and be paid in full upon demand being made by FON therefore.

API hereby waives demand and presentment for payment, notice of non-payment, protest, notice of protest, notice of dishonour, bringing of suit and diligence in taking any action.

DATED at Fort Erie, Ontario, as of this 17th day December 2018.

ALGOMA POWER INC.

R. Scott Hawkes
President and Chief Executive Officer

Glen King
Vice President, Finance and Chief Financial Officer

Settlement Proposal – Pre-Settlement Clarification Questions SEC-42/Staff11-Ch. 2 Updates (Excel Only)

Algoma Power Inc.
EB-2024-0007

SCHEDULE B

PARTIAL DECISION AND ORDER

ACCOUNTING ORDER – DEFINED BENEFIT PENSION PLAN VARIANCE ACCOUNT

ALGOMA POWER INC.

EB-2024-0007

NOVEMBER 19, 2024

ACCOUNTING ORDER - Defined Benefit Pension Plan Variance Account

Account 1508 - Other Regulatory Assets, Sub-Account Defined Benefit Pension Plan Variance Account (DBVA)

This account includes the variance between the Defined Benefit Pension Plan included in the 2025 OM&A portion of the revenue requirement base rates ($25,579) and actuals during the subsequent IRM years. Algoma Power will track costs at a sufficiently detailed level to assist in a prudence review of the costs incurred.

The following accounts are established to record the amounts described above incurred on or after January 1, 2025.

- Account 1508 - Other Regulatory Assets, Defined Benefit Pension Plan Variance Account (DBVA)
- Account 1508 - Other Regulatory Assets, Defined Benefit Pension Plan Variance Account (DBVA), Sub-Account Carrying Charges

Sample Journal Entries:

Revenue Requirement Variance

The entry below, to be booked by Dec 31st of each year starting in 2025 until the next rebase, assumes the proposed defined benefit amount attributed to OM&A in base rates is less than the actual, entry is flipped if the proposed amount is greater than actual, entries expected to vary year-to-year.

Dr. Account 1508 - Other Regulatory Assets, Defined Benefit Pension Plan Variance Account (DBVA)

Cr. 5645 Employee Pension and Benefits

To record pension OM&A expense variance between the amount included in base rates and actual.

Carrying Charges (2025 Test Year to Next Rebase)

The entry below assumes net debit balance in Account 1508 - Other Regulatory Assets, DBVA per above, entry flipped if net credit balance.

Dr. Account 1508 - Other Regulatory Assets, Defined Benefit Pension Plan Variance Account (DBVA), Sub-Account Carrying Charges

Cr. 4405 Interest and Dividend Income

To record the carrying charges on the net monthly opening balance in Account 1508 - Other Regulatory Assets, Defined Benefit Pension Plan Variance Account (DBVA), Sub-Account Carrying Charges.

<u>Disposition – Future Proceeding</u>

In a future Cost of Service proceeding, balances accumulated in the DBVA Sub-accounts above will be requested for disposition, after which the approved balances will then be moved from the Sub-Accounts into an Account 1595 Sub-Account. Rate riders will be then applied against the accumulated balances to reduce the outstanding balance towards $Nil. Carrying charges will be recorded monthly on the outstanding principal balance using the OEB-prescribed interest rates until the balance is fully disposed of.

SCHEDULE C

PARTIAL DECISION AND ORDER

ACCOUNTING ORDER – #4 CIRCUIT SECTION C-E SALE DEFERRAL ACCOUNT

ALGOMA POWER INC.

EB-2024-0007

NOVEMBER 19, 2024

ACCOUNTING ORDER - #4 Circuit Section C-E Sale Deferral Account

Account 1508 - Other Regulatory Assets, Sub-Account #4 Circuit Section C-E Sale Deferral Account (4CircuitC-E)

This account is to track the revenue requirement impact of the sale of any part of the #4 Circuit to a 3rd party, should such a sale occur. Algoma Power will track costs at a sufficiently detailed level to assist in a prudence review of the costs incurred.

The following accounts are established to record the amounts described above incurred on or after January 1, 2025.

- Account 1508 - Other Regulatory Assets, #4 Circuit Section C-E Sale Deferral Account (4CircuitC-E)
- Account 1508 - Other Regulatory Assets, #4 Circuit Section C-E Sale Deferral Account (4CircuitC-E), Sub-Account Carrying Charges

Sample Journal Entries:

Revenue Requirement Variance

Entry below, to be booked by Dec 31st of each year starting in 2025 until the next rebasing, assumes the proposed sale resulted in an overcollection of revenue requirement due to overstatement of rate base in base rates following the sale of the assets.

Dr. Account 4080 Distribution Services Revenue

Cr. Account 1508 - Other Regulatory Assets, #4 Circuit Section C-E Sale Deferral Account (4CircuitC-E)

To record the revenue requirement impact of the sale of a part of the #4 Circuit Section C-E.

Carrying Charges (2025 Test Year to Next Rebasing)

The entry below assumes net debit balance in Account 1508 - Other Regulatory Assets, #4 Circuit Section C-E per above, entry flipped if net credit balance.

Dr. Account 6035 Other Interest Expense

Cr. Account 1508 - Other Regulatory Assets, #4 Circuit Section C-E Sale Deferral Account (4CircuitC-E), Sub-Account Carrying Charges

To record the carrying charges on the net monthly opening balance in Account 1508 - Other Regulatory Assets, #4 Circuit Section C-E Sale Deferral Account (4CircuitC-E), Sub-Account Carrying Charges.

Disposition – Future Proceeding

In a future Cost of Service proceeding, balances accumulated in the #4 Circuit Section C-E Sub-accounts above will be requested for disposition, after which the approved balances will then be moved from the Sub-Accounts into an Account 1595 Sub-Account. Rate riders will be then applied against the accumulated balances to reduce the outstanding balance towards $Nil. Carrying charges will be recorded monthly on the outstanding principal balance using the OEB-prescribed interest rates until the balance is fully disposed of.

SCHEDULE D

PARTIAL DECISION AND ORDER

ACCOUNTING ORDER – LAND USE REVENUE REQUIREMENT VARIANCE ACCOUNT

ALGOMA POWER INC.

EB-2024-0007

NOVEMBER 19, 2024

<u>ACCOUNTING ORDER - Land Use Revenue Requirement Variance Account (LURR VA)</u>

Account 1508 - Other Regulatory Assets, Sub-Account Land Use Revenue Requirement Variance Account (LURRVA)

This account includes the variance between land use baseline related revenue requirement included in 2025 base rates (revenue requirement related to USoA 1612 capital component is $2,067,985, and OMA component in USoA 5095 is $124,122 in 2025 Test Year) and actual during the subsequent IRM years. Algoma Power will track costs at a sufficiently detailed level to assist in a prudence review of the costs incurred.

The following accounts are established to record the amounts described above incurred on or after January 1, 2025 (including the 2025 revenue requirement impacts of capitalized agreements established in 2024).

- Account 1508 - Other Regulatory Assets, Land Use Revenue Requirement Variance Account (LURRVA) OMA
- Account 1508 - Other Regulatory Assets, Land Use Revenue Requirement Variance Account (LURRVA) Capital
- Account 1508 - Other Regulatory Assets, Land Use Revenue Requirement Variance Account (LURRVA), Sub-Account Carrying Charges

Sample Journal Entries:

<u>Revenue Requirement Variance (2025 Test Year to Next Rebase)</u>

Entries below, to be booked by Dec 31st of each year starting in 2025 until the next rebase, assume the proposed land use amount in base rates is less than actual, entry flipped if the proposed amount is greater than actual, entries expected to vary year-to-year.

<u>OMA</u>

Dr. 1508 Other Regulatory Assets, Land Use Revenue Requirement Variance Account (LURRVA) OMA

Cr. 4080 Distribution Services Revenue

To record the variance between the amount included in the revenue requirement and the actual for OMA.

<u>Capital</u>

Dr. 1508 Other Regulatory Assets, Land Use Revenue Requirement Variance Account (LURRVA) Capital

Cr. 4080 Distribution Services Revenue

To record revenue requirement variance between the amount included in base rates and the actual for capital.

Note: The capital component would be calculated in accordance with revenue requirement calculation methodology and would include consideration for amortization expense, PILs, ROE, and interest expense.

Carrying Charges (2025 Test Year Until Approved Disposition)

The entry below assumes net debit balance in Account 1508 - Other Regulatory Assets, LURRVA per above, entry flipped if net credit balance.

Dr. 1508 Other Regulatory Assets, Land Use Revenue Requirement Variance Account (LURRVA) OMA, Sub-Account Carrying Charges

Dr. 1508 Other Regulatory Assets, Land Use Revenue Requirement Variance Account (LURRVA) Capital, Sub-Account Carrying Charges

Cr. 4405 Interest and Dividend Income

To record the carrying charges on the net monthly opening balance in Account 1508 - Other Regulatory Assets, Land Use Variance Accounts (LURRVA).

Disposition – Future Proceeding

In a future Cost of Service proceeding, balances accumulated in the LURRVA 1508 accounts above will be requested for disposition, after which the approved balances will then be transferred from the Sub-Accounts into an Account 1595 Sub-Account.

On the clearing of the LURRVA Capital sub-account, Algoma Power will dispose of 100% of the net cumulative capital related revenue requirement if the net cumulative balance is a credit pay-back to customers, or 70% of the net cumulative capital related revenue requirement if that net cumulative balance is a debit to be recovered from customers. On the clearing of the LURRVA OMA sub-account, Algoma Power will dispose of 100% of the cumulative balance reported in the OMA sub-account, whether it is a credit or a debit balance, subject to a prudence review.

Upon approval of disposition, rate riders will be applied against the accumulated balances to reduce the outstanding balance towards $Nil. Carrying charges will be recorded monthly on the outstanding principal balance using the prescribed interest rates set by the OEB until the balance is fully disposed of.