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

BY E-MAIL

August 14, 2024

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Marconi:

Re: Algoma Power Inc. (Algoma Power)
2025 Cost of Service Rate Application
Ontario Energy Board (OEB) File Number: EB-2024-0007

In accordance with Procedural Order No. 1, please find attached OEB staff's interrogatories in the above noted proceeding. Algoma Power and all intervenors have been copied on this filing.

Algoma Power's responses to interrogatories are due by September 4, 2024. Responses to interrogatories, including supporting documentation, must not include personal information unless filed in accordance with rule 9A of the OEB's *Rules of Practice and Procedure*.

Yours truly,

Birgit M. Armstrong
Digitally signed by Birgit M. Armstrong
Date: 2024.08.14 15:34:01 -04'00'

Birgit Armstrong
Senior Advisor – Electricity Distribution Rates

cc. All parties to EB-2024-0007

OEB Staff Interrogatories

2025 Electricity Distribution Rates Application
Algoma Power Inc. (Algoma Power)
EB-2024-0007
August 14, 2024

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Exhibit 1 – Administration

1-Staff-1
Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from Ontario Energy Board (OEB) staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), 12 and 13 (Rate Design) as well as the RRRP tab should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2024 Electricity Distributor Rate Applications webpage.

1-Staff-2
Activity and Program Benchmarking
Ref 1: 2022 Unit Cost Calculations - October 11, 2023
Ref 2: Exhibit 1, Table 22, p. 72
Ref 3: Exhibit 1, p. 77

Preamble:
References 2 provides a summary of the Activity and Program Benchmarking unit cost results for Metering OM&A from reference 1.

In reference 2, Algoma Power states that:

The higher-than-average Metering OM&A are in part due to the ongoing presence of hard-to-reach remote manually read meters. Algoma Power noted that its ability to limit manual meter reads is limited due to communication challenges with meters located in remote areas that make automated meter reading very difficult.

Algoma Power further noted that cost increases are forecasted over the next few years due to inflationary impact. However, Algoma Power noted that the allocation of metering department time to the Smart Metering capital program beginning in 2025 will result in a reduction over 2023/2024.

Reference 1 shows the following Unit costs ($/Customers) Metering OM&A for the historic period 2018-2022.

Unit Costs ($/Customers)

2018	2019	2020	2021	2022	Avg.
74.85	70.72	75.25	70.64	73.56	73.00

Question(s):

a) Reference 2 (Exh. 1, Table 22, p. 72) shows a constant cost of $74.85 per customer for Metering OM&A, while Reference 1 provides costs shown in the table above. Please explain the difference.
b) Please provide the allocation of the metering department's time for the Smart Metering capital program to Algoma Power.
c) Please provide a breakdown of smart meters to manually read meters in the Algoma Power service area.
d) In reference 3, Algoma Power notes that it has commissioned a study to evaluate the feasibility and performance of the cellular communication network throughout its service territory. Please explain the impact of the growth and evolution of the cellular network in recent years on the expansion of smart meters and the forecasted impact on Metering OM&A going forward.

1-Staff-3
Activity and Program Benchmarking
Ref 1: Exhibit 1, Table 22, p. 72

Preamble:
References 1 provides a summary of the Activity and Program Benchmarking unit cost results for Lines O&M OM&A from reference 1.

Question(s):

a) Please confirm the unit cost values from 2018 to 2023 Lines O&M. Through RRR OEB staff has unit values which appear to be offset by +1 year as seen provided below.

Distributor	Unit Cost ($/Circuit km of Primary Line)					
	2019	2020	2021	2022	2023	Average
Algoma Power Inc.	529.73	773.46	649.35	791.34	668.59	682.49

1-Staff-4
Revenue Requirement Variance
Ref 1: Exhibit 1, pp. 31-32 and Table 2

Preamble:
On p. 31 of Exhibit 1, Algoma Power noted that proposed Service Revenue Requirement for the 2025 test year of $35,768,551 reflects an increase of $2,654,124 or 36.1% relative to 2020 Board approved.

In table 2, the evidence shows a service revenue requirement of $26,284,138 for 2020 Board approved.

Question(s):

a) Please confirm that the $ amount increase is $9,484,413, which represents a 36.1% increase.

Exhibit 2 – Rate Base and Capital

2-Staff-5
2024 Bridge Year Actuals
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Distribution System Plan Part 1, Table 4.26, p.155

Preamble:
Algoma Power has provided its forecasted capital plan for 2024 but has not specified how many months of data are included in the forecast as actual spending.

Question(s):

a) Please update Chapter 2 Appendices 2-AA, 2-AB, 2-BA, and other affected models to reflect updates to 2024 estimates, if any.
b) Please provide the actual spending to date for each project or program in 2024. Please clarify for how many months of actuals are included in the 2024 budget.
c) Please correct the models for 2022, given that 2-AA has a capital expenditure of $11k for the Subtransmission Line Rebuilds. In reference 2, the capital expenditure is listed at $11k.

2-Staff-6
Planned versus Actual Historical Spending
Ref 1: Chapter 2 Appendix 2-AB

Preamble:
OEB staff has created the following table outlining the planned and actual cumulative gross and net spending for 2020-2024.

Table 1: Planned vs. Net Spending (2020-2024) ($ millions)

	Planned	2020-2023 Actual + 2024 Forecast	Variance (%)
Gross Capital Expenditures	60.0	92.7	54%
Net Capital Expenditures	59.5	86.3	45%

Question(s):
a) Given that Algoma Power plans to spend 45% more over 2020-2024 than it had forecasted in its 2020 Distribution System Plan, please explain what specific measures were taken to reprioritize or defer projects to ensure prudent spending.

2-Staff-7
METSCO Asset Condition Assessment
Ref 1: API Asset Condition Assessment, pp. 65-66
Ref 2: API Asset Condition Assessment, Table 4-1, p. 26
Ref 3: Distribution System Plan part 1, Table 3.6, p.85

Preamble:
METSCO conducted an Asset Condition Assessment for Algoma Power. In reference 1, METSCO noted that Algoma Power's quality and availability of data was generally low. METSCO made several recommendations to improve the quality and availability of data for different asset types.

In reference 2, METSCO could not calculate a valid health index for overhead conductors, underground cables, distribution transformers, or reclosers.

In Table 3.6 of reference 3, Algoma Power provided a breakdown of assets by health index distribution from very good to very poor.

Question(s):

a) Please explain if and/or how Algoma Power has addressed or plans to address the recommendations made by METSCO when it comes to improving data availability and data quality.
b) Did METSCO provide a flag-for-action plan or a recommendation of how many assets of each type to address per year?
c) Is Algoma Power improving its testing methods going forward so that a valid health index can be calculated for overhead conductors, underground cables, distribution transformers, and reclosers?
d) The Health Index Distribution shown in Table 3.6 indicates that Algoma Power has very few assets in Poor or Very Poor condition. Please quantify how many assets in Fair or better condition Algoma Power plans to replace during the rate period based on the proposed capital investment levels.

2-Staff-8
Customer-Hours Interrupted
Ref 1: Distribution System Plan part 1, Table 2.15, p.58

Preamble:
In Table 2.15 of reference 1, Algoma Power provided a breakdown of customer-hours interrupted by cause code.

Question(s):

a) What happened in 2023 to drive the outlier customer hours interrupted due to defective equipment?
b) Please provide a breakdown of defective equipment customer interruptions and customer hours of interruption by asset type each year.
c) Please identify the capital investments targeted in the test year at reducing outages caused by , 3 – Tree Contacts and 5 – Defective Equipment?

2-Staff-9
Reliability Targets
Ref 1: Distribution System Plan part 1, p.42
Ref 2: Distribution System Plan part 1, p.61

Preamble:
In reference 2, Algoma Power states:

“API sets targets annually for its reliability performance, which normally involve a set percentage improvement over a multi-year rolling average performance. This target therefore incentivizes continuous improvement in reliability performance.”

Question(s):

a) What has changed materially in customer preference that API is targeting an improvement in SAIDI from 7.36 to 5.42?
b) What has changed materially in customer preference that API is targeting an improvement in SAIFI from 3.16 to 2.47?
c) Have customers stated they want continuously improving reliability, rather than maintaining reliability and controlling costs?

2-Staff-10
Tree Contacts and Major Event Days
Ref 1: Distribution System Plan part 1, p.141
Ref 2: Distribution System Plan part 1, Table 2.12, p.48

Preamble:
In reference 1, Algoma Power states:

“Under API’s line rebuild program, API is generally installing taller, stronger poles which will inherently result in better reliability and resilience.”

As per reference 2, tree contacts represent the preponderance of number of outages, number of customers interrupted, and number of customers hours interrupted pertaining to Major Event Days.

Question(s):

a) Considering that the most significant proportion of Algoma Power outages (including major event days but excluding Loss of Supply) are driven by Tree Contacts (reference 2), please explain and quantify how increased investment in taller, stronger poles will mitigate outages caused by such events.
b) Please provide the Benefit-Cost Analysis used to justify the installation of “*taller, stronger poles which will inherently result in better reliability and resilience.”*
c) What would be the cost difference to the line rebuild programs in each year of the forecast period if like-for-like poles are used instead of taller, stronger poles?

d) Please confirm that capital expenditures do not typically mitigate Major Event Day (MED) outages caused by 3 - Tree Contacts.
    a. If not confirmed, please explain which capital investments improve MED results, and quantify the correlation between increased spending and improved results.

2-Staff-11
Outage Trends
Ref 1: Distribution System Plan part 1, Table 2.13, p.55
Ref 2: Distribution System Plan part 1, Figure 2.12, p.55

Preamble:
Table 2.13 in reference 1 shows an increasing trend in the number of outages for several cause codes.

Figure 2.12 in reference 1 shows an increasing trend in number of outages per year excluding MEDs but including 1-Scheduled Outage, 2-Loss of Supply, and 9-Foreign Interference.

Question(s):

a) What is causing the increasing frequency of outages caused by 0 - Unknown/Other, 1 - Scheduled Outage and 9 - Foreign Interference?
b) What is causing the decreasing frequency of outages caused by 3 – Tree Contacts?
c) Please restate Figure 2.12 in reference 2 after removing 1-Scheduled Outage, 2-Loss of Supply, and 9-Foreign Interference.

2-Staff-12
Wildfires
Ref 1: Distribution System Plan part 1, p.73

Preamble:
In reference 1, Algoma Power states:

“Given the nature of API’s service territory, API is very aware of potential risks associated with wildfires. As a result, API is in the process of developing a wildfire mitigation plan and strategy, that will outline the protocols that would be followed to further mitigate the wildfire risks.”

Question(s):

a) When will the wildfire mitigation plan and strategy be completed?
b) Please quantify any planned rate period expenditures that may need to be modified after the wildfire mitigation plan and strategy are available.

2-Staff-13
Vulnerability of Assets
Ref 1: Distribution System Plan part 1, p.73

Preamble:
In reference 1, Algoma Power states:

"API's line rebuilds programs (distribution and subtransmission), target in general the most vulnerable poles in API's service territory. These rebuild will result in a stronger distribution network."

Question(s):
a) Please describe how "most vulnerable" is determined.
b) How does Algoma Power take into account the 'risk' when determining which poles to replace? Specifically, how are the probability and consequence of failure taken into account.

2-Staff-14
Accessibility
Ref 1: Distribution System Plan part 1, p.82

Preamble:
In reference 1, Algoma Power states:

"Prior to 2009, many of these sections were accessible via rail through informal agreements between API (or its predecessor companies) and Algoma Central Railway ("ACR"). Rail cars would generally be provided on a cost basis for both forced outage situations and for planned work. Following the acquisition of ACR by Canadian National ("CN") Rail, API has been unable to obtain reliable rail access to these sections. In 2021, Watco purchased this rail line from CN, and since then API has had discussion with Watco regarding establishing agreements to use the rail but has not yet been able to obtain formal rail access to these sections."

Question(s):

a) Please describe how Algoma Power adapted its asset management strategy to address restricted access to sections that were previously accessible by rail.
b) What are the incremental rate period costs (by year) resulting from the restricted access?

2-Staff-15
Distribution Line Rebuilds & Subtransmission Line Rebuilds
Ref 1: Chapter 2 Appendix 2-AA

Preamble:
Algoma Power spent on average $3.7 million from 2020-2023 in its Distribution Line Rebuilds program. In 2024, the program cost increased to $5.5 million.
Algoma Power spent on average $131k on the Subtransmission Line Rebuilds program from 2020-2023 (assuming $11k was spent on the program in 2022). In 2024, the program cost increased to $2.0 million and $1 million each year of the forecast period.

Question(s):
a) Please provide a table outlining how many poles were replaced each year from 2020 to 2023 and how many are estimated to be replaced in 2024-2029 separated by the Distribution Line Rebuilds program and the Subtransmission Line Rebuilds program.
b) Please provide another table similar to the last question but for all poles replaced in all of Algoma Power's programs.
c) How many poles have been replaced to date in 2024 in each program?
d) Please explain the need for increased spending in the bridge year for each program and the increased budget for the Subtransmission Line Rebuilds program over the forecast period given the downward trend in SAIDI and SAIFI.
e) What is the estimated count of poles in each health index class by the end of the rate period if program spending is reduced by 10% for each of the two programs separately?

2-Staff-16
Line Rebuild Program Replacement Rationale
Ref 1: Distribution System Plan part 1, p.32
Ref 2: Appendix 2-H

Preamble:
In reference 1, Algoma Power states:

"API's Line Rebuild program is the core of API's sustaining asset replacement strategy and is predicated on the proactive approach to asset replacement. Proactive asset replacement allows for the replacement of older, at end-of-life assets, prior to failure. The result is a balance between the cost of the asset replacement and relatively larger costs, reliability impacts, and safety concerns associated with reactive replacement of these assets. The proactive approach also affords more efficient mobilization of material, equipment, and crews as well as provides the least impact on reliability and improves infrastructure resiliency."

In Reference 2, Algoma Power forecasted a loss of $25,000 in USoA 4360 loss on disposition of utility and other property for bridge year and test year.

Question(s):

a) What is the annual probability of failure of poles due largely to asset condition? Please provide the probability of failure organized by Health index category.
b) Please explain how Algoma Power avoids prematurely replacing its assets, especially for those asset types without a calculated health index and for poles, where a health index has not been calculated for 20% of the population.
c) What is the annual probability of failure of pole top transformers in each Health index category?
d) How many poles are being replaced in totality by assessed condition category for each of the planning period years?
e) Please provide the business case to justify premature retirement to the anticipated reliability benefits to customers.
f) Please provide the journal entry for the proactive asset replacement.
g) Please confirm if the forecasted loss in other revenues is related to the proactive asset replacement. If not, please explain.
h) Please explain how Algoma Power derives its forecast of the loss of $25,000 on the disposition of the utility assets.
i) Please confirm that the forecasted loss of $25,000 is to increase the revenue requirement rather than decrease the revenue requirement.

2-Staff-17
Pole Expected Life and Health Index Distribution
Ref 1: Distribution System Plan part 1, Figure 3.13 & Figure 3.14, pp. 92-93

Preamble:
In reference 1, Algoma Power provided a separate count of wood poles by age and by health index.

Question(s):

a) Please provide a table for the data in Figure 3.13 of reference 1 that shows the Health Index by age category.
b) Based on available data what is the expected service life (not depreciation life) of wood poles used for asset planning purposes?

2-Staff-18
Transformer Service Life
Ref 1: Distribution System Plan Part 1, pp. 86-87

Preamble:
In reference 1, Algoma Power states:
"API currently has 14 power transformers and 2 voltage regulating transformers in-service, located within API's distribution stations. Of API's sixteen total assets, fifteen had sufficient data to form a health index, two of which were in Fair or worse condition. The breakdown of station transformer and voltage regulator assets, their data availability index ("DAI"), and their calculated Health Index("HI") is presented in Table 3.7
…
The transformer in Fair condition, at Garden River DS, has reached a more advanced age (31 years in service) and scored poorly on the dissolved gas analysis and very poorly on the oil quality analysis. The transformer in Fair condition, at Wawa #2, is of a significantly advanced age (44 years in service) and has serious deficiencies in its physical condition. There is evidence of an oil leak on the conservator tank, damage to relays and paint, and significant corrosion of its control wiring."

Question(s):
a) Please explain why Algoma Power considers 31 years to be an "advanced age" for a winter peaking transformer and why Algoma Power believes the Garden River DS scored poorly on the gas and oil quality analysis at this age.
    i. Has this transformer been replaced or are there plans to replace it? If so, in which capital program, what year, and at what cost?
b) What are Algoma Power's expected service lives (not depreciation lives), respectively, for power transformers, regulating transformers and pole top transformers?
    i. Are the expected service lives of each of these transformer classes greater than, less than or equal to their depreciation life? Please explain for each class.
c) Does Algoma Power plan to retire any classes of assets at the end of their depreciation lives?

i. If yes, please identify those asset classes and explain why they are retired at the end of their depreciation lives.

2-Staff-19
Ratio Bank Transformers
Ref 1: Distribution System Plan Part 1, pp.95-96

Preamble:
In reference 1, Algoma Power states:

"22 of API's ratio-bank transformers have enough data to construct a valid health index, 20 of which of which are currently installed. The average health index of installed units is 95%. Figure 3.16 shows the HI results for this asset class…No recommendations to improve the health index formulation of the ratio bank transformers."

Question(s):

a) Please provide the failure rates of Ratio Bank Transformers for each of the past 5 years.
b) Please provide the planned replacement rates of these assets for each year of the forecasted period.

2-Staff-20
Electrification
Ref 1: Distribution System Plan part 1, p.115
Ref 2: Distribution System Plan part 1, p.75

Preamble:
In reference 2, Algoma Power developed a load forecast with and without consideration of electric vehicle and electrification adoption growth. Algoma Power used a 1.7% annual growth to forecast the load growth due to these technologies.

In reference 1, Algoma Power noted that it changed its distribution transformer standard size from 15kV to 25kV and 37kVA due to the onset of electrification and electric vehicle charging requirements.

Also in reference 2, Algoma Power stated that it will consider opportunities to install larger capacity transformers when installing new or needing to replace an existing transformer (e.g. end-of-life replacement). Algoma Power also noted that there was still uncertainty around the timing of when these load increases would be realized.

Question(s):

a) Given that Algoma Power has changed its distribution transformer size standard due to electrification, please confirm if Algoma Power up-sizes all new and replacement transformers, or if it “consider[s] opportunities to install larger capacity transformer[s]” as per reference 2?
b) Given that Algoma Power is uncertain about the timing of when these load increases would be realized (as per reference 2), what was the rationale behind changing Algoma Power’s standard transformer size?

2-Staff-21
Right of Way Access Program
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Distribution System Plan Part 1, p.183

Preamble:
Algoma Power spent on average $69k from 2020-2023 in its ROW Access Program. From 2024-2029, the average spend in this program is forecasted to be $172k.

In reference 2, Algoma Power states that “the quality of the access can further affect the costs of on-going maintenance activities. Poor access will cause O&M costs to be higher than sections with better access.”

Question(s):

a) Please explain the increased spending in this program in 2024 and 2025 ($288k and $226k respectively).
b) Has Algoma Power quantified the 2025 O&M savings due to the increased capital spending from the ROW Access program? If not, please quantify the expected savings and explain how this savings has been applied to the OM&A budget.

2-Staff-22
Vehicles
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Distribution System Plan Part 1, p.108

Preamble:
Algoma Power plans to spend $0.6 million in 2024 and 1.2 million in 2025 on transportation and work equipment according to reference 1. In reference 2, Algoma Power notes that “annual allowance is made for replacement of one aerial device, as well as about three pickup trucks and a variety of other items as required.”

Question(s):

a) Please explain the basis for the proposed significant increase in annual spending on transportation and work equipment above historical average spending.
b) Please explain what fleet vehicles are being replaced in 2024 and 2025. What are the conditions of the vehicles, including age, mileage, etc.
c) What is the cost of each vehicle being replaced in 2024 and 2025? Have vehicles already been ordered for these two years? Are costs for vehicles that have not yet been ordered based on inflationary estimates or quotes?
d) What is the status of the vehicle acquisitions for 2024?
e) Has Algoma Power considered the electrification of its fleet? If so, why is it choosing not to electrify its fleet. If not, why not?

2-Staff-23
Business Systems
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Exhibit 2, p.50

Preamble:
Algoma Power increased spending in its Business Systems program in 2024 to $485k. Algoma Power notes in reference 2 that the capital expenditure is an investment in SCADA, including 20 relay intelligent electronic devices which are planned to come online and connect to the SCADA system in 2024. The functionality of these devices initially includes remote supervision, real-time system monitoring and fault indication during outages.

Question(s):

a) Please provide the cost-benefit rationale for proceeding with this project versus the alternative of doing nothing.
b) What is the status of this project?

2-Staff-24
Buildings, Facilities & Yards
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Distribution System Plan Part 1, pp.187-188

Preamble:
Algoma Power plans to increase spending in the Buildings, Facilities & Yards program in the 2025 Test Year to $214k.

Question(s):

a) Please list the capital expenditures that form the 2025 budget for the buildings, facilities & yard program. Are these costs related to the new Sault St. Marie Facility?
b) Please provide the need and priority level for the individual projects that make up the 2025 budget for this program, including why spending has increased in 2025 for this program.

2-Staff-25
Communication & SCADA
Ref 1: Chapter 2 Appendix 2-AA

Preamble:
Algoma Power plans to spend $480k in its Communication & SCADA program from 2025 through 2028.

Question(s):
a) Please explain what the capital expenditures are for in this program from 2025 through 2028.

2-Staff-26
Goulais Area Voltage Conversion
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Distribution System Plan Part 1, pp.171
Ref 3: Distribution System Plan part 1, p.125

Preamble:
Algoma Power plans to spend $297k on the Goulais Area Voltage Conversion project in 2025.

According to reference 2, the entire project would consist of converting 202km of overhead primary distribution, upgrading 891 transformers, and reinsulating 1,948 distribution poles.

In reference 3, Algoma Power states:
"HOSSM had identified a need to refurbish their Batchawana TS. At the time of submitting its previous DSP, API was just beginning to discuss alternatives for refurbishment work at this station. In July 2019, API commissioned a Greenfield TS study, which considered the alternatives presented by HOSSM in the supply configuration in the Batchawana and Goulais region. The recommendation of this report was to pursue refurbishing both stations and indicated that there would be significant challenges in operating at the existing supply over the next 15 years."

Question(s):

a) Please explain how much of this work in reference 2 is being completed in the 2025 test year.
b) Please confirm that there is no overlap in work to be completed between the voltage conversion project and the distribution lines or subtransmission lines rebuild programs.
c) Based on reference 3, What proportion of the ultimate Batchawana and Goulais region 25 kV conversion costs does this early investment in the Batchawana TS refurbishment represent?
d) Based on reference 3, what is the estimated NPV cost saving attributable to undertaking this early investment now versus deferring the investment until the 25 kV upgrade is needed in the next 10 to 15 years?

2-Staff-27
Protection, Automation, Reliability
Ref 1: Chapter 2 Appendix 2-AA
Ref 2: Exhibit 2, p.46
Ref 3: Distribution System Plan Part 1, pp.173-175

Preamble:
Algoma Power plans to spend $1.5M in the Protection, Automation, Reliability program in 2024, and $758k in 2025.

As per reference 2, in 2024, Algoma Power will complete additional subtransmission reliability project work, specifically the Desbarats Distribution Station refurbishment and Batchawana Transmission Station Supply Reconfiguration.

As per reference 3, in 2025, Algoma Power will complete two projects: upgrading the primary transformer protections at the Bar River DS (Project D) and procuring suitable contingency replacement for the power transformer at the Dubreuiville Sub 87 (Project E).

Question(s):

a) Please break down the need and cost of the two reliability projects in 2024 as described in reference 2.
b) Please provide the status of the two projects described in reference 2 for 2024.
c) Please break down the cost of the five reliability projects (Project A-E) in the forecast period as described in reference 3 by year. Why are costs so much greater in 2025 and 2026?

d) It appears the alternatives considered and the cost-benefit analysis provided in reference 3 is for Project A (with an in-service date of 2027). Please provide the alternatives considered and cost-benefit analysis for Project D and E (with an in-service date of 2025).

2-Staff-28
#4 Circuit 10MW Capacity Increase Project
Ref 1: Exhibit 2, pp.6-8
Ref 2: Chapter 2 Appendix 2-AA/AB
Ref 3: Exhibit 2, p.40

Preamble:
Algoma Power stated that "in early 2022, API entered into an agreement for the "Goudreau East 44kV Expansion Project" to construct 11.2km of new and replacement 44kV lines and remove 9.2km of existing line along the #4 Circuit." The project facilitates the request to provide 8MW in total incremental General Service >50kW load.

The gross cost of the project was $11.2M according to Algoma Power. Algoma Power added a replacement credit or capital contribution of $3.5M in the 2024 in-service additions representing the discounted value of work which Algoma Power would have completed in the future if the assets were not replaced early due to the customer-driven need.

In reference 3, Algoma Power noted that there were additional related project costs of $1.7M with an offsetting capital contribution of $1.7M (with a net nil impact).

Question(s):

a) Please confirm if the 8MW incremental load forecast was determined by the industrial customer(s) or by Algoma Power.
b) Please clarify what the additional related project costs of $1.7M pertain to.
c) Please clarify based on the quote in reference 1, whether any of the 11.2km of line is being replaced. If so, why wasn't a credit determined for this portion of the line?
d) Please provide an Excel workbook with the calculations in Table 2 of reference 1. In the Excel workbook, please show a breakdown of the discount factor.
    a. In the same Excel workbook, please provide a comparative calculation of the contribution amount using the OEB-approved inflation factors for 2023, 2024, and 2025 of 3.7%, 4.8%, and 3.6% respectively instead of 2%.

2-Staff-29
Echo River TS ACM Project
Ref 1: Distribution System Plan part 1, Table 4.7, p.124

Preamble:
In Table 4.7 of reference 1, Algoma Power provided a breakdown of the Echo River TS ACM Project budget and the total actual cost variance.

Question(s):
a) Please explain why Algoma Power did not budget for any of its own activities i.e., Algoma Power Internal Cost, Study Cost (for Alternative & Business Case), Modification required to Algoma Power Wholesale Meter as part of its ACM request.
b) Please explain the recourse available to Algoma Power when HOSSM notifies it of material cost increases above the CCRA estimate amount.
    i. Please describe the actions taken (beyond those described in reference 1 and Exhibit 2) by Algoma Power to validate each of the proposed HOSSM cost increases and to mitigate the impact of those cost increases on the total project cost.

2-Staff-30
Sault Ste. Marie Facility ACM
Ref 1: Exhibit 2, pp.80-84
Ref 2: Exhibit 2, p.72
Ref 3: Exhibit 2, p.76
Ref 4: Exhibit 2, Table 41, p.79
Ref 5: Exhibit 2, p.75

Preamble:
In reference 1, Algoma Power conducted a benchmarking study comparing various OEB-approved building costs. As part of the benchmarking study, Algoma Power removed the geotechnical issues ($417k) from its actual cost for comparison with the other buildings, noting that these geotechnical issues were outside of Algoma Power's control and are unlikely to have occurred at the other comparators.

In reference 2, Algoma Power notes that following a competitive bidding process, the contract for the project was awarded to S&T Group at a value of $14.7M.

In reference 3, Algoma Power notes that it installed overhead doors, a motorized shop door, and motorized gates to the new facility costs.

Question(s):

a) Please provide the Excel sheet showing all calculations in producing Table 43 in reference 1.
b) Can Algoma Power confirm that the other comparators in the benchmarking study did not have other complications outside of their control (not strictly geotechnical related)? If not, please provide the benchmarking analysis with the geotechnical issues included.
c) Please provide the value of the other bids received for the project.
d) Reference 4 indicates that it was unclear what proportion of the cost overrun was attributable to Covid-19. Please make best efforts to estimate the proportion of the project cost overrun attributable to Covid-19.
e) Please confirm whether the old facility had motorized shop doors/gates. If so, why weren't these additions included in the initial ACM budget? If not, what is the new need for these additions?
f) Please explain why the parking and driveway modifications as detailed in reference 5 were not considered at the time of the initial ACM filing.

2-Staff-31
Sault Ste. Marie Facility ACM - Operational Efficiencies
Ref 1: Exhibit 2, pp.86-87

Preamble:
In reference 1, Algoma Power provided a list of efficiency improvements as a result of the new facility. Algoma Power notes that for the most part, it cannot quantify these efficiency improvements.

Question(s):
a) Please confirm whether Algoma Power has accounted for any efficiencies from the Sault Ste. Marie Facility in its 2024 and 2025 OM&A budgets.

2-Staff-32
NWS/CDM in Distribution System Planning
Ref 1: EB-2024-0118, Non-Wires Solutions Guidelines for Electricity Distributors, March 28, 2024
Ref 2: EB-2024-0007, Exhibit 2 – Rate Base & Distribution System Plan, Distribution System Plan, Part 1, Attachment 2A, Section 5.3.5

Preamble:
Per the OEB's Non-Wires Solutions Guidelines for Electricity Distributors (NWS Guidelines), electricity distributors are required to incorporate consideration of non-wires solutions (NWSs) into their distribution system planning process by considering whether a distribution rate-funded NWS may be a preferred approach to meeting a system need,

thus avoiding or deferring spending on traditional infrastructure. Per the NWS Guidelines, traditional conservation and demand management (CDM) is a potential NWS that electricity distributors may consider. Furthermore, electricity distributors are required to document their consideration of NWSs when making investment decisions on electricity system needs with an expected capital cost of $2 million or more as part of distribution system planning, excluding general plant investments.

Algoma Power has indicated that it is not aware of any planned CDM programs within its service territory which would need consideration in its system planning. Further, Algoma Power noted that it will continue to consider CDM opportunities to address system needs and will consider the relative costs and benefits associated with a CDM option.

Question(s):

a) Please describe how Algoma Power has addressed or plans to address the requirement in the OEB's NWS Guidelines for distributors to incorporate consideration of NWSs into their distribution system planning process.

Exhibit 3 – Customer and Load Forecast

3-Staff-33
Customer Forecast
Ref 1: Exhibit 3, page 20

Preamble:
Algoma Power states,
"*During the COVID-19 pandemic, API observed above-average customer growth due to individuals relocating from other areas of the province. API believes this trend was limited to the COVID-19 pandemic, and is unlikely to continue. API considers that the geomean excluding 2020, 2021 and 2022 presents a more accurate viewpoint of the typical customer growth expected in future years, now that COVID impacts are slowing. Additionally, 2020 had an above normal increase due to the acquisition of a new service area, ie: the customers of the former Dubreuil Lumber Inc. (DLI)"*

Algoma Power has used historical customer/connection usage from 2014 to 2023 to forecast future usage.

Question(s):

a) Please provide customer numbers for all rate classes for the most recent historical months available for 2024.

b) Please provide a customer forecast based on the geomean from 2014-2023.

3-Staff-34
Energy Forecast
Ref 1: Exhibit 3, page 24

Preamble:
Algoma Power states,

> *"API believes that 2023 represents an appropriate assumption for post pandemic usage per customer, reflecting new trends such as a long-term increase in working from home, but not the impacts of stay-home or other emergency public health requirements."*

Question(s):

a) Please provide a rate class consumption model based on average annual kwh usage per customer from 2014-2023 applied to the forecasted customer counts for the bridge and test years.
b) Did Algoma Power undertake any analysis to test the impact of COVID-19 on the load forecast (e.g., including a Covid variable in the regression model)? If so, please provide the results. If not, please explain why not.

3-Staff-35
Load Forecast
Ref 1: Exhibit 3, page 5
Ref 2: DSP, page 75

Preamble:
Algoma Power provided a load forecast in Exhibit 3. In reference 2, Algoma Power provides a load projection based on an annual increase of 1.7% associated with EV charging and electrification.

Question(s):

a) Has Algoma Power considered the impact of Distributed Energy Resources or other emerging technologies such as electric vehicles on its load forecast provided in Exhibit 3? Please explain your response.

3-Staff-36
Load Forecast
Ref 1: Exhibit 3, page 25
Ref 2: Distribution System Plan part 1, Figure 3.3, p.75

Preamble:
In reference 1, Algoma Power states,
"For the R2 commercial class, API has made a manual adjustment to increase the forecast for the anticipated load associated with increased customer usage from the #4 Circuit project which is detailed in Exhibit 2. The project will bring 8MW in increased maximum customer load."

OEB staff notes that the load forecast for R2 rate class includes a manual adjustment of 86,880 kW and 51,899,642kWh.

Question(s):
a) Please explain the derivation and provide the full calculation of the 86,880 kW and 51,899,642kWh manual adjustments included in the load forecast.
    a. Does the 0.905 multiplier in the calculations represent a 91% power factor?
    b. Does the calculation account for the actual peak load of the industrial customers? If not, why not?
b) Please explain why Algoma Power has accounted for the increased load due to the new industrial customer in 2023 in Figure 3.3 of reference 2 but has made a manual adjustment for the 8MW increase in the 2025 load forecast as per reference 1.
c) Does the load forecast in reference 1 account for the 0.92% annual growth increase included in Figure 3.3 of reference 2? If not, why not?

Exhibit 4 – Operations, Maintenance & Administration

4-Staff-37
OM&A Summary
Ref 1: Exhibit 4, p. 5
Ref 2: Appendix 2-Jc

Question:
a) Please provide a revised version of Appendix 2-JC with an additional column showing year-to-date actuals.

4-Staff-38
Use of Non-Wires Solutions to Meet Identified Customer Needs
Ref 1: EB-2024-0007, Exhibit 4 – Operating Expenses, Section 4.8.1
Ref 2: EB-2023-0125, Benefit-Cost Analysis Framework for Addressing Electricity System Needs, May 16, 2024

Preamble:
Algoma Power indicated that it has received a request for a connection for which a non-wires solution (NWS) may be a viable option to meet a customer's need. Further, Algoma noted that it is examining the wires and NWSs options available to meet this specific customer's need, while considering the OEB's Benefit-Cost Analysis (BCA) Framework and the customer's needs and preferences.

The OEB's BCA Framework consists of a pre-assessment, distribution service test, and optional energy system test that electricity distributors are to use when evaluating the viability of NWSs to meet a given electricity system need.

Question(s):
a) Please provide further details as to the specific need for which an NWS may be a viable option. In the response, please identify the specific wires and NWS options under consideration for evaluation.
b) Please confirm whether Algoma Power is seeking ratepayer funding as part of the current application to address the identified customer need. If so, please provide the total estimated costs of the wires and NWSs under consideration.
c) If ratepayer funding is being sought, please confirm whether the pre-assessment stage of the BCA Framework has been applied for this system need. If so, please provide the rationale and outcome of the pre-assessment.
d) If ratepayer funding is being sought, please confirm whether the distribution service test or energy system test were employed for this system need. If so, please provide the outcomes of the tests employed using the OEB approved templates required by the BCA Framework.

4-Staff-39
Corporate Cost Allocation
Ref 1: Exhibit 4, pp. 70-71
Ref 2: Ch. 2 Appendices, Tab 2-N Corp_Cost_Allocation
Ref 3: EB-2021-0011 CNPI 2022 CoS_Ch. 2 Appendices, Tab 2-N Corp_Cost_Allocation
Ref 4: Exhibit 1, p. 25

Preamble:

On p. 70 of Ref. 1, the shared services include: executive; finance; information technology; human resources; health, safety and environmental; regulatory; and procurement and contract management. In Ref. 4, Algoma also listed legal and engineering as a shared service.

Algoma Power noted that the corporate cost allocation methodology, which includes the relative percentage allocation to the Fortis Ontario business units, are updated when Canadian Niagara Power Inc. (CNPI) rebases.

In Ref. 2, CNPI allocated 24% or $1,690,874 for administrative services to Algoma in its 2022 CoS application.

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
FortisOntario	CNPI-Distribution	corporate services	cost based	$554,988	$554,988	21%
FortisOntario	CNPI-Distribution	building rent	market based	$410,315	$410,315	65%
CNPI-Distribution	Cornwall Electric	administrative services	cost based	$1,285,749	$1,285,749	19%
CNPI-Distribution	FortisOntario	administrative services	cost based	$148,284	$148,284	2%
CNPI-Distribution	CNPI-Transmission	administrative services	cost based	$343,874	$343,874	5%
CNPI-Distribution	Algoma Power	administrative services	cost based	$1,690,874	$1,690,874	24%
Cornwall Electric	CNPI-Distribution	administrative services	cost based	$20,189	$20,189	13%
Fortis Inc.	CNPI-Distribution	administrative services	cost based	$259,044	$259,044	0%
CNPI-Distribution	Cornwall Electric	shared IT & equipment	cost based (Note 1)	$382,675	$382,675	21%
CNPI-Distribution	FortisOntario	shared IT	cost based (Note 1)	$38,070	$38,070	3%
CNPI-Distribution	CNPI-Transmission	shared IT & equipment	cost based (Note 1)	$125,576	$125,576	7%
CNPI-Distribution	Algoma Power	shared IT	cost based (Note 1)	$478,299	$478,299	31%

In its 2025 CoS application, Algoma Power showed the following corporate cost allocation from CNPI totalling $2,092,148, which is a 24% increase over the cost CNPI allocated in 2022:

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
FortisOntario	API	corporate services	cost based	22%	$639,570
FortisOntario	API	building rent	market based	13%	$88,223
CNPI-Distribution	API	Finance & Purchas	cost based	32%	$718,385
CNPI-Distribution	API	IT	cost based	31%	$726,351
CNPI-Distribution	API	HR	cost based	34%	$180,588
CNPI-Distribution	API	Health, Safety, Env	cost based	34%	$321,528
CNPI-Distribution	API	Regulatory	cost based	40%	$145,296
Fortis Inc.	API	administrative servi	cost based	0%	$183,747
CNPI-Distribution	API	shared IT	cost based (Note 1	31%	$431,621

Question(s):

a) Please confirm that administrative services of $1,690,874 approved as part of CNPI's cost of service application includes the same services in the amount of $2,092,148 highlighted in the table above.
b) Please explain the cost increases for each service provided by CNPI from 2022 onwards by departments in more detail.
c) Please confirm that the 'building rent' charged by Fortis Ontario to Algoma Power is not included in the fully allocated costs for services charged by CNPI. Please provide a more detailed explanation for this cost allocation.

4-Staff-40
Corporate Cost Allocation – Administrative Service
Ref 1: Ch. 2 Appendices, 2-N, 2025 Corporate Cost Allocation

Preamble:
In Ref 1, Algoma Power shows a corporate cost allocation of 0% from Fortis Inc. to Algoma Power for administrative service but applies a cost of $183,474.

Question(s):
a) Please explain why Fortis Inc. charges Algoma $183,747 for administrative service given the allocated cost is 0%.
b) If costs are allocated to Algoma Power, please provide the percentage over the last five years and a detailed description of the service(s).
c) Please update Appendix 2-N if necessary.

4-Staff-41

Cloud Computing
Ref 1: Exhibit 1, p. 74

Preamble:
On p. 74, Algoma Power noted that the increase for administrative services from CNPI to Algoma Power in the amount of $426,815 from 2020 Board Approved to 2025 Test is due to general increases in labour, material and contracted service costs.

Algoma Power stated that cybersecurity related costs continue to increase, and the implementation of the cloud computing standard gives rise to additional third party maintenance agreement costs that were previously capitalized.

Question(s):

a) Please confirm that third party maintenance agreement cost are based on subscription-based model/cloud-based solution. If not, please explain what is included in this cost.
b) Please complete the following tables on capital and OM&A spending between on-premise solutions and subscription-based model/cloud-based solutions.

Costs for On-premise Solutions from 2020-2029

	2020	2021	2022	2023	2024
Capex	$	$	$	$	$
OM&A	$	$	$	$	$

	2025	2026	2027	2028	2029
Capex	$	$	$	$	$
OM&A	$	$	$	$	$

Costs for Subscription-based/Cloud-based Solutions from 2020-2029

	2020	2021	2022	2023	2024
Capex	$	$	$	$	$
OM&A	$	$	$	$	$

	2025	2026	2027	2028	2029
Capex	$	$	$	$	$
OM&A	$	$	$	$	$

c) Please explain any cost savings as a result of moving to a subscription-based model or cloud-based solutions which Algoma Power would otherwise incur with on-premise solutions.

4-Staff-42
Vegetation Management
Ref 1: Exhibit 4, pp. 28-37 and Table 7
Ref 2: Ch. 2 Appendices, Tab 2-JB_OM&A Cost Drivers

Preamble:
On p. 28 of Ref 1, Algoma Power noted that the increase in vegetation management is due to the volume of work, as well as variations in the cost per unit to complete the work.

On p. 35, Algoma Power noted that the $1.24M increase compared to 2020 Board-approved is due to the following factors:

- An increase in the level and cost of work required for brush control, as a result of lower ability to complete brush control though herbicide application during this cycle
- An additional increase in the cost of work required for brush control, as a result of brush growth volume caused by inability to apply herbicide in past years/cycles
- An estimated $745k increase or 21% in costs associated with general inflation since 2020
- Above-inflationary levels of increases in contractor cost per km pricing (estimated at 26%)

Question(s):

a) Please provide Algoma Power's current vegetation management plan for the last five years as well as its five-year plan going forward.
   i. Please discuss Algoma Power's vegetation management plan with respect to the clearing of hazard trees in addition to brush management.
b) Please provide the customer interruptions as well as customer hours of interruption due to tree contacts to date. Please explain the decreases in 2021 and 2023.
c) Please explain what is special about the test year with respect to cost trends and vegetation management program unit costs that causes the single year step increase in spending.
d) OEB staff notes that in 2020, Algoma Power was able to maintain 280km of medium to heavy density brush. Please explain why Algoma Power feels that vegetation management for a forecast length of 355 km of line with medium density/complexity is achievable in the 2025 test year.
e) Please provide a table showing the break-down of in-house labour vs. third-party contractors' costs for vegetation management.
   i. Please provide a variance analysis from year to year for each category.
   ii. Provide an explanation how Algoma Power determines whether to use contractors vs. internal labour.
f) Has Algoma Power considered a shorter vegetation management cycle?
g) OEB staff noted that the per km cost of $13,567.42 for the test year represents an increase of 5.67% over 2020. Please explain the above noted inflationary increase of 21% compared to this increase.

4-Staff-43
Land Use Fees
Ref 1: Exhibit 4, pp. 37
Ref 2: Ch. 2 Appendices, Tab 2-JB_OM&A Cost Drivers
Preamble:
Algoma Power stated the following:

> *ROW Land Fees have fluctuated during the historical (2020 to 2023) period primarily as a result of one-time payments such as legal fees in relation to the negotiation of agreements. API incurred significant such costs in 2022, with non-material costs also impacting the costs in 2021 and 2023. The first annual payment under an ongoing annual agreement was introduced in 2021, which will be relatively stable in future years (and increases with inflation). Additionally, in 2023, API recorded "catch up" payments related to 2019-2023.*

In Ref 1, Algoma Power noted that rights payments for the 2025 test year are budgeted to be $767,909 per year.

On page 37, Algoma Power noted that it capitalizes easements and/or other permanent agreements, as well as the costs required to facilitate these costs.

Question(s):

a) Please provide a detailed breakdown, including one-time payments such as legal fees, from 2020 to 2025.
b) Please provide the year to date expense for the 2024 bridge year and explain the increase in RoW Land Fees of $386k in the test year over the bridge year.
c) Please provide the breakdown between capitalized and expensed ROW Land Fees from 2020 to 2023 and forecasted cost for the brigde and test year.

	2020	2021	2022	2023	2024	2025
Capex	$	$	$	$	$	$
OM&A	$	$	$	$	$	$

4-Staff-44
Engineering Cost
Ref 1: Exhibit 4, p. 41
Ref 2: Exhibit 4, pp. 62-65
Ref 3: Ch. 2 Appendices, 2-JC

Preamble:

Algoma Power noted that some of the increase in direct time allocated to Algoma Power if due to general operating engineering support for area planning studies provided to Algoma Power.

As per the data provided in Appendix 2-JC, OEB staff calculated that the average cost for the supervision and engineering program from 2020 actual to the 2024 test year is $226,755. Algoma Power's requests for this program in the 2025 test year is $258,583, which represents a 14% increase over the average.

Question(s):

a) Please provide a further justification for the increase to this line item and note how much of the increase is due to the direct time allocation for engineering support.
b) Compared to the historical years, Algoma Power forecasts a 36% decrease in capital spending for the next five years. Please explain why it is appropriate to allocate more time and costs for engineering support to Algoma Power given this decrease.

4-Staff-45
Overhead lines and feeders
Ref 1: Exhibit 4, p. 53
Ref 2: Appendix 2-JC

Preamble:

In Ref 2, Algoma Power shows an increase of $800k in overhead lines and feeders expenses in the test year over 2020 OEB-approved. On p. 53 of Exhibit 4, Algoma Power indicates that the increase for this line item over this time period is $441k.

In Ref 1, Algoma Power stated that the increase is primarily the result of a combination of increased right of way land fees, outage costs and general maintenance of overheads services as follows: Right of Way land fees of $299,000, maintenance of overhead services of $57,000 and outage increase of $90,000.

Questions:

a) Please confirm that the increase over 2020 OEB-approved cost for this line item is $806,174.
b) If so, please explain what causes the remainder of the increase and provide detailed explanation for each driver.

4-Staff-46

Compensation
Ref 1: Exhibit 4, p. 41
Ref 2: Exhibit 4, pp. 62-65
Ref 3: Ch. 2 Appendices, 2-N, 2025 Corporate Cost Allocation

Preamble:
On p. 41 of Exhibit 4, Algoma Power stated that the 2025 Test year total FTE of 74 is an addition of four FTE as compared to 2020 Board Approved and this 6% increase is a combination of an additional new hire for operations administrative support, and more operational (i.e. customer service and engineering) direct time allocation to Algoma Power from the operations group of another FortisOntario group of companies.

The increase in direct time allocation is a result of enhanced billing and customer engagement, general operating engineering support for area planning studies and GIS system operations, and internal legal support provided to Algoma Power.

In addition, on p. 64, Algoma Power noted that increased affiliated allocation includes allocated time from a new GIS position at FortisOntario.

Question(s):

a) Algoma noted that the 4 new FTEs are due to a combination of an additional hire and more operational direct time allocated to Algoma Power. Please provide a breakdown of the four FTEs.
b) Please show the time allocated to the various affiliates for each direct time allocation as shown in the table below. Please add rows if necessary.

Position	% allocated API	% allocated to CNPI	% allocated to Fortis Inc.	% allocated to Fortis Ontario

c) Please provide the quantum associated with each allocation.
d) Please confirm that these FTEs are not included in shared corporate costs allocated to Algoma from its affiliates.
e) For new hires 100% allocated to Algoma Power, please provide the business case for the creation of the new position(s).

4-Staff-47

Internal Legal Support
Ref 1: Exhibit 4, p. 41

Preamble:
Algoma Power noted that some of the increase in direct time allocated to Algoma Power is due to internal legal support provided to Algoma Power.

Question(s):

a) Please provide a more detailed explanations for this increase and confirm that this expense is not covered under the corporate costs allocated to Algoma Power by its affiliate. If it is, please provide the affiliate and the quantum that provides legal services to Algoma Power.
b) Please discuss Algoma Power's expectations to continue increased legal support in relation to the Right of Way Land Fee cost driver.

4-Staff-48
Pension and OPEB
Ref 1: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, page 31
Ref 2: Exhibit 4, Section 4.4.3, Pension Expense and Post Retirement Benefits Expense

Preamble:
Chapter 2 Filing Requirements states that:

> *The distributor must provide details of employee benefit programs, including pensions, other post-employment retirement benefits (OPEBs), and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for in the last OEB-approved rebasing application, and for historical, bridge and test years. The most recent actuarial report(s) must be included in the pre-filed evidence and be reconciled with the pension and OPEBs amounts (as applicable). The basis on which pension and OPEBs amounts are forecast for the bridge and test years must also be explained. What is documented in the tax section of the evidence must agree with this analysis."*

In Reference 2, Algoma Power states that:

> *The actuarial reports will not be directly reconcilable to pension and OPEB*

expense amounts reported in bridge and test years given the differing accounting standards and the multiple DVA accounts relating to pension and OPEB.

Table 19 of reference 2 outlines Defined Benefit Pension Plan expenses from 2020 Board Approved to Test Year 2025.

Table 19 - Defined Benefit Pension Plan Expenses and Assumptions

Defined Benefit Pension Plan	2020 Board Approved	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Pension Expense	$284,218	$418,656	$625,390	$399,693	$93,410	$44,415	$42,998
Pension Expense Allocated to Capital	$102,533	$151,849	$260,996	$154,089	$37,262	$17,254	$17,419
Pension Expense Allocated to OM&A	$181,685	$266,807	$364,394	$245,604	$56,148	$27,161	$25,579
Significant assumptions used:							
Discount rate	3.70%	3.20%	2.70%	3.30%	5.30%	4.60%	4.90%
Expected long-term rate of return on plan assets	5.25%	4.85%	4.35%	4.70%	5.75%	5.75%	5.75%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%

Table 21 of Reference 2 outlines Post Retirement Benefits expenses and assumptions used for the 2020 Board Approved to 2025 Test.

Table 21 - Post Retirement Benefits Expenses and Assumptions

Post-Retirement Benefits Expense	2020 Board Approved	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Post-retirement benefit costs	$540,111	$601,600	$672,600	$619,200	$472,960	$565,600	$547,500
Post-retirement benefit costs Allocated to Capital	$194,847	$218,205	$280,698	$238,713	$188,669	$219,724	$221,800
Significant assumptions used:							
Discount rate	3.90%	2.80%	3.30%	5.30%	4.60%	4.60%	5.20%

OEB staff outlines the capital and OM&A allocation percentages for the defined benefit pension expenses and the post retirement benefits (OPEBs) expenses in the table below.

Table 1: Capital and OM&A Allocation

	2020 Board Approved	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Birdge Year	2025 Test Year
Defined Benefit (DB) Pension Expense	284,218	418,656	625,390	399,693	93,410	44,415	42,998
Allocation to Capital	102,533	151,849	260,996	154,089	37,262	17,254	17,419
DB Pension: Capital Allocation	**36.08%**	**36.27%**	**41.73%**	**38.55%**	**39.89%**	**38.85%**	**40.51%**
Allocation to OM&A	181,685	266,807	364,394	245,604	56,148	27,161	25,579
DB Pension: OM&A Allocation	**63.92%**	**63.73%**	**58.27%**	**61.45%**	**60.11%**	**61.15%**	**59.49%**
OPEBs Costs	540,111	601,600	672,600	619,200	472,960	565,600	547,500
Allocation to Capital	194,847	218,205	280,698	238,713	188,669	219,724	221,800
OPEBs: Capital Allocation %	**36.08%**	**36.27%**	**41.73%**	**38.55%**	**39.89%**	**38.85%**	**40.51%**

Question(s):

a) OEB staff notes from Table 19 that the defined benefit pension expense has decreased significantly from $399,693 in 2022 to $99,410 in 2023 and the expense is forecasted to further decrease to $44,415 in 2024 and $42,998 in 2025 while the corresponding discount rates have increased from 3.30% in 2022 to 5.3% in 2023, 4.6% in 2024 and 4.9% in 2025. Given the inverse relationship between the discount rate and pension liability and pension expense, please explain why the defined benefit pension expense has decreased significantly from 2022 despite the discount rate having increased since 2022.

b) Please explain the changes in the allocation between the capital expenditures and OM&A expenses compared to the 2020 allocation percentages in the 2020 rebasing application.

c) Algoma Power stated that “the actuarial reports will not be directly reconcilable to pension and OPEB expense amounts reported in bridge and test years given the differing accounting standards and the multiple DVA accounts relating to pension and OPEB”.

   i. Please explain whether the actuarial reports support the pension and OPEB expenses recorded on Algoma Power’s audited financial statements. If so, please provide the reconciliation between the actuarial reports and the pension and OPEB expenses on the audited financial statements. If not, please explain why not.

   ii. Please elaborate further on what are the differing accounting standards and how the different accounting standards impact the pension and OPEB expenses in bridge and test years.

   iii. Please elaborate further on what are the multiple DVAs and how these DVAs impact the pension and OPEB expenses in the bridge and test years.

4-Staff-49
Pension and OPEB

Ref 1: Algoma Power's 2020 Cost of service application EB-2019-0019, settlement proposal, pages 47 and 48
Ref 2: Exhibit 9, DVA continuity schedule
Ref 3: Exhibit 4, Section 4.4.3, Pension Expense and Post Retirement Benefits Expense

In Reference 1, The Parties agreed to remove the amortization of net actuarial gains in 2020 which resulted in increased capital expenditures of $8,038 and increased OM&A expenses of $14,244.

OEB staff summarizes the removal of the amortized actuarial gains and losses outlined in Table 21 of Reference 1 in the table below:

Table 2: Amortized Actuarial Gains and Losses in Pension and OPEB Expense in Last Rebasing Application

	Defined Benefit Pension Plan	**Post Retirement Benefit**	**Total**
Amortized Gain/(loss) (from Table 21 of 2020 Settlement Proposal)	54,418	(76,700)	(22,282)
Amortized Gain/(loss) allocated to capital (from Table 21 of 2020 Settlement Proposal)	19,631	(27,670)	(8,039)
Amortized Gain/(loss) allocated to OM&A (calculated by OEB staff)	34,787	(49,030)	(14,243)

In Reference 3, OEB staff notes that the 2020 Board approved Pension and OPEB expenses align with the Pension and OPEB expenses, excluding amortized actuarial gains and losses, as outlined in Reference 1.

Additionally, in Reference 1, the Parties agreed to accumulate all actual amortized actuarial gains and losses in the following accounts starting from the effective date of the 2020 cost of service proceeding: Account 1508, Subaccount – Amortized Pension Actuarial Gains/Losses and Account 1508, Subaccount – Amortized OPEB Actuarial Gains/Losses.

In this rate application, according to Reference 2, Algoma Power requests the continuance of these two DVAs.

Question(s):

a) Please clarify the treatment of the actuarial gains/loss of pension and OPEB in this application.
    i. Please confirm If the amortization of the actuarial gains/losses is included in the revenue requirement.
    ii. If confirmed, please explain why Algoma changed its proposal of the treatment for actuarial gains/losses in this application and not request for discontinuance of the two DVAs mentioned above.
    iii. If not, please confirm that Algoma is proposing to continue the regulatory treatment of the pension and OPEB as approved in its last rebasing application (i.e. use the two DVAs to continue tracking the actuarial gains/losses)
b) Please provide the actuarial gains/losses of pension and OPEB respectively since 2020.

Exhibit 5 – Cost of Capital

5-Staff-50
Ref 1: EB-2024-0063, Notice, March 6, 2024
Ref 2: EB-2024-0063, OEB Letter, April 22, 2024

Preamble:
On March 6, 2024, the OEB commenced a hearing (EB-2024-0063) on its own motion to consider the methodology for determining the values of the cost of capital parameters and deemed capital structure to be used to set rates for electricity transmitters, electricity distributors, natural gas utilities, and Ontario Power Generation Inc. The methodology for determining the OEB’s prescribed interest rates and matters related to the OEB’s Cloud Computing Deferral Account will also be considered, including what type of interest rate, if any, should apply to this deferral account.

On April 22, 2024, the OEB approved the final Issues List for this proceeding, including the following two issues, amongst other issues:

18. How should any changes in the cost of capital parameters and/or capital structure of a utility be implemented (e.g., on a one-time basis upon rebasing or gradually over a rate term)?

19. Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle of an approved rate term, and if so, how?

Question:

a) Please confirm that the applicant proposes to implement the outcomes from the OEB's generic cost of capital proceeding, including what the OEB decides with respect to implementation. If this is not the case, please explain.

5-Staff-51
Ref 1: EB-2024-0063, OEB Letter, July 26, 2024

Preamble:
On July 26, 2024, the OEB issued a Letter and Accounting Order regarding prescribed interest rates and the deemed short-term debt rate (DSTDR).

Question(s):

a) Please confirm that the applicant will use the 2025 DSTDR to be set in October 2024 on an interim basis.
b) Please confirm that the applicant will follow all other direction included in the OEB's Letter and Accounting Order issued on July 26, 2024, including the establishment of a new variance account for the DSTDR.

5-Staff-52
Long Term Debt
Ref 1: Exhibit 5, Page 12-13, 16
Ref 2: Ch. 2 Appendices, Tab 2-OB_Debt Instruments
Ref 3: Exhibit 5, Attachment 5B

Preamble:
In 2024 Algoma Power is planning to secure an additional $55M in third party debt, to bring its actual capital structure to more closely match the OEB deemed structure. In doing this, API plans to also retire all its existing affiliated debt of $12.75M.

Algoma Power has assumed debt issuance of $55M at a 6% interest rate based on recent research, issued on July 1, 2024.

The rate on the promissory note is 3.21%

Questions:

a) Please provide the updated information about the new loan expected to be funded on July 1, 2024.
b) What due diligence has Algoma Power undertaken to ensure its preferred lender is offering a competitive rate and product?
c) Please explain why Algoma Power decided to finance during a high rate environment, given that Algoma Power has been drawing from Short Term Debt since 2021.
d) Please explain why Algoma Power plans to use new loan with forecasted rate of 6% to repay existing affiliated debt with a rate of 3.21%.

Exhibit 6 – Revenue Requirement

6-Staff-53
Other Revenue – Other Electric Revenues
Ref 1: Chapter 2 Appendix 2-H
Ref 2: Exhibit 6, pp. 26-27
Ref 3: Accounting Procedures Handbook (APH) Guidance March 2015, section 13

Preamble:
Appendix 2-H in reference 1 shows a breakdown of Account 4220 – Other Electric Revenues which includes returns on rate base and PILS accruals for the ACM projects.

In reference 2, Algoma Power states that:

> *OEB 4220 has a balance in 2023 of $1,009,072 (2022 $64,796) related to a combination of the return on rate base and grossed-up PILS for the two ACM projects, based on the number of months the assets were in service in 2023 (12 months for the Sault building, 5 months for the Echo River substation project). OEB 4305 increased primarily related to $188,688 (2022 $Nil as the catch-up for 2022 was recorded in 2023) in PILS amount recorded with offset to OEB 1592 for the two ACM projects. The offset amount has been recorded under OEB 1110.*
>
> *OEB 4220 has a balance in 2024 of $1,234,000 (2023 $1,009,792) related to a combination of the return on rate base and grossed-up PILS for the two ACM projects, based on months in service in 2023 (12 months for both the Sault building and the Echo River substation project). OEB 4305 includes a credit balance in 2024 of $44,000 (2023 debit balance of $188,688) related to PILS amount recorded with offset to OEB 1592 for the two ACM projects.*

In reference 3, the APH Guidance from March 2015, section 13 provides guidance on how to record ACM projects.

Question(s):

a) Please provide the accounting entries for the two ACM projects including the rate riders/ RRRP funding recovery.
   i. Please describe the accounting treatment for revenues collected for Algoma Power's R1 and R2 rate classes vs. Seasonal and Streetlighting customers.
b) Please explain why Algoma Power has included ACM revenue requirement amounts in other revenues Account 4220 - Other Electric Revenues when the assets were in service, rather than transferring the in-service assets from construction work in progress to the 1508 Subaccount and recording the ACM depreciation expenses in the 1508 Subaccount, as required by the OEB accounting guidance provided in Reference 3.

6-Staff-54
Other Revenue – Pole Rental Revenue
Ref 1: Chapter 2 Appendix 2-H

Preamble:
Algoma Power evidence in Ref 1 shows and average revenue offset of $498,515 from 2020 actual to 2024.

Question(s):

a) Please explain why Algoma Power is estimating an income of $444,000 from pole rentals, which is approx. 11% below the average.

6-Staff-55
PILs
Ref 1: 2025 PILs Workform
Ref 2: Appendix 2-BA

Preamble:
In Reference 2, Algoma Power reports a total depreciation of $6,320,421 for the Test Year, based on a total PP&E of $276,304,269, which includes the addition of the ACM assets.

According to Tab T1 in Reference 1, Algoma Power adjusts regulatory taxable income by adding back the total depreciation before deducting the CCA amounts calculated in

Tab T8 Sch 8 CCA Test. The total depreciation of $6,320,421 reported as an addition to the regulatory taxable income matches the total depreciation reported in Appendix 2-BA. However, OEB staff notes the CCA amounts calculated in Tab T8 Sch 8 CCA Test are based on the UCC without the addition of the ACM assets.

Question(s):

a) Please confirm the OEB staff's observation and explain why the ACM assets are not included in the Tab 8 CCA Test in the Test Year.
b) Please update the 2025 PILs Workform to reflect the inclusion of the ACM assets in the Test Year.

6-Staff-56
PILs
Ref 1: Exhibit 6, S.6.4.2, page 18
Ref 2: Exhibit 6, Attachment 6C, 2023 API Corporate Tax Return
Ref 3: EB-2019-0019 Decision and Order, Nov 07, 2019, 2020 RRWF
Ref 4: 2025 PILs Workform
Ref 5: 2006 Electricity Distribution Rate Handbook, May 11, 2005

Preamble:
In Reference 1, Algoma Power notes "a taxable loss was triggered primarily as a result of enhanced CCA in 2023 as shown in the PILS model; however, that loss is being carried back and will be applied to 2022 taxable income. 2024 Bridge and 2025 Test Years both show positive taxable income." As per Tab H1 of Reference 4, Algoma Power has reported a taxable loss of $1,465,677 in 2023.

In its 2023 corporate income tax return as filed in Reference 2, Algoma Power has elected to carry back the current year loss of $1,728,346 to the previous tax year, with a remaining balance of $31,012 available for future tax years.

According to Reference 3, OEB staff notes that Algoma Power's approved PILs in its 2020 cost of service application is a debit amount of $333,974.

Section 7.2.3 of the 2006 Electricity Distribution Rate Handbook (2006 EDR Report) states that,

> *A distributor expecting to have any loss carry-forwards still available on December 31, 2005 must disclose the amount of those loss carry-forwards in the 2006 application, and apply them in full to reduce the taxable income calculated*

in the 2006 regulatory tax calculation. These amounts are to be entered in the 2006 OEB Tax Model.

Question(s):

a) Please reconcile the tax loss of $1,728,346 filed in the 2023 corporate income tax with the loss of 1,465,677 reported in the 2025 PILs Workform.
b) Please explain why Algoma Power believes it is reasonable to carry back the 2023 tax loss to the 2022 taxable income instead of carrying it forward, as stated in the 2006 EDR Report.
c) Please provide the 2025 PILs Workform based on the scenario where the tax loss is carried forward to the bridge and test years.

6-Staff-57
Accelerated CCA
Ref 1: Exhibit 6, section 6.4.2, pages 18 – 19
Ref 2: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, pages 63-64
Ref 3: OEB Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, July 25, 2019

Preamble:
In Table 12 of Reference 1, Algoma Power outlined the CCA variance of $269,942 accumulated in Account 1592, Sub-Account CCA changes for 2018 and 2019.

Additionally, Algoma Power has proposed to smooth the phase-out of the accelerated CCA by adjusting “the 2025 Test Year PILS amount equal to 1/5 of the grossed up PILs impact of the calculated CCA differences for the years 2028 to 2029 under the current enhanced CCA rates in effect for 2025, and the elimination of enhanced CCA rates that will be in effect for those same years.”

According to Reference 3, the OEB issued a letter in 2019 while establishing the sub-account CCA changes under Account 1592. The letter states that:

> *Under the Accounting Procedures Handbook, electricity distributors and transmitters are to record the impact of any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the OEB Tax Model that is used to determine the tax amount that underpins rates.*

The letter also states that:

> *The OEB expects Utilities, including those whose applications are currently before the OEB, to reflect any impacts arising from CCA rule changes in their cost-based applications for 2020 rates and beyond. The OEB recognizes that there may be timing differences that could lead to volatility in tax deductions over the rate-setting term. The OEB may consider a smoothing mechanism to address this.*

Section 2.9.1.5 of the Filing Requirements states that distributors are to provide calculations for accelerated CCA differences per year, based on actual capital additions. These calculations should include:

- The undepreciated capital cost (UCC) continuity schedules for each year, itemized by CCA class.
- The calculated PILs/tax differences.
- The grossed-up PILs/tax differences.
- Any other applicable information.
- Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable.
- A reconciliation of these amounts to the amounts presented in the Account 1592 sub-account for CCA changes in the DVA continuity schedule.

Question(s):

a) Please provide the following information as noted in Section 2.9.1.5 of the Filing Requirement to support Account 1592 – PILS and Tax Variances requested in this application for disposition:
   i. The undepreciated capital cost (UCC) continuity schedules for each year, itemized by CCA class.
   ii. A reconciliation of these amounts to the amounts presented in the Account 1592 sub-account for CCA changes in the DVA continuity schedule, if necessary.

6-Staff-58
Other Taxes
Ref 1: Exhibit 6, page 20
Ref 2: Exhibit 2, pages 70-71

Preamble:
In Reference 1, Algoma Power has proposed property tax expenses of $260K for the 2025 Test Year compared to the $119K approved in its 2020 cost of service application.

Algoma Power states that the increases in property taxes started in 2023 due to property taxes being paid on the new facility in Sault Ste. Marie.

According to Reference 2, Algoma Power completed its land purchase agreement on the 12.08-acre parcel of land located at 251 Industrial Park Crescent in Sault Ste. Marie. The purchase agreement included the purchase of 7.94 acres of land for the new work centre with severance and reconveyance of 4.14 acres of the property back to its original owner.

Question(s):

a) Please provide a breakdown of the $260k property tax expense by the facilities.
b) Please confirm the budgeted property taxes for the new facility in Sault Ste. Marie, included in the total proposed 2025 property tax expenses of $260K, is for the 7.94 acres of land for the new work centre.

Exhibit 7 – Cost Allocation

7-Staff-59
Cost Allocation
Ref 1: Exhibit 7, page 19
Ref 2: EB-2019-0019, Cost Allocation Model DRO, Tab I6.2

Preamble:
The status quo revenue to cost ratio for the Street Lighting rate class is 44% and seasonal rate class is 74.63%. Algoma Power has proposed to gradually increase the revenue to cost ratio for Street Lighting to the lower limit of OEB's policy range over 5 years and for the seasonal rate class over 3 years. In order to maintain revenue neutrality Algoma Power proposes to reduce the revenue to cost ratio of the Residential R2 rate class.

Question(s):

a) Can Algoma Power identify the reasons for the marked difference in the status quo revenue to cost ratio between 2020 cost of service in reference 2 and 2025 for the street lighting rate class?
b) Please explain how the number of bills issued to streetlighting rate class have changed significantly between 2020 in reference 2 and 2025? The number of bills in 2020 was 15 vs in 2025 it's 13,871.

c) Please describe any other rate mitigation proposals considered by Algoma Power for the Street Lighting and seasonal rate class and why they were not proposed in the current application.

7-Staff-60
Weighting Factors
Ref: Exhibit 7, p. 12 and Cost Allocation Model, Tab I5.2

Preamble:
OEB staff notes that weighting factors for some of the rate classes have changed compared to the last OEB approved weighing factors used in 2020 for Billing and Collecting.

Question(s):
a) Please provide the derivation of the proposed weighting factors.
b) Please explain why the weighting factors have changed from the 2020 OEB approved.

Exhibit 8 – Rate Design

8-Staff-61
Ref 1: Tariff Schedule and Bill Impact Model
Ref 2: OEB Letter - 2025 Inflation Parameters

Preamble:
The Tariff Schedule and Bill Impact Model in reference 1, Tab 3 contains Miscellaneous Service Charges which are calculated based on an inflation factor of 4.8% for 2023.

In reference 2, the OEB has recently issued a letter on June 20, 2024 with updated 2025 Inflation Parameters. In the letter, the OEB states that it has calculated the 2025 inflation factor for electricity distributors to be 3.6%.

Question(s):
a) Please update the Miscellaneous Service Charges in Tab 3 (reference 1) to reflect the 2025 inflation factor of 3.6%.
b) Please revise other tabs in reference 1 to reflect the update in (a).

8-Staff-62
RRRP Adjustment Factor
Ref 1: RRWF

Ref 2: Appendix A

Preamble:
In Appendix A, OEB staff has provided an updated RRRP adjustment factor of 4.75% and the associated analysis.

Question:

a) Please review and confirm that Algoma Power agrees with the calculated RRRP adjustment factor of 4.75%.
b) If not, please revise the analysis and explain what has been revised as applicable.

8-Staff-63
Fully Fixed Rate Design
Ref 1: Exhibit 8, p. 16
Ref 2: RRWF

Preamble:
Algoma Power stated that it has used the RRWF, with adjustments, to calculate the adjustment for the Seasonal rate class. In the scenario where Algoma Power applied the $4 incremental amount to the fixed rate for the Seasonal Class, the Seasonal bill impact at the 10th percentile of usage (ie: a small Seasonal customer using only 15kWh per month), the total bill impact exceeded the 10% threshold.

For the Seasonal rate class, Algoma Power is proposing to maintain the current fixed-variable split of 8%/92%.

Question(s):

a) Please provide a schedule showing the fixed variable/split for each remaining transition year.
b) Please state how many seasonal customers are at the 10^{th} percentile.
c) Please provide a scenario showing the continued transition towards a fully fixed rate design for seasonal customers, including the associated bill impacts.

8-Staff-64
Retail Service Transmission Rates
Ref 1: RTSR Workform
Ref 2: EB-2024-0183_2024 Uniform Transmission Rates Update, June 27, 2024

Preamble:

On June 27, 2024 the OEB issued its decision and order on updated Uniform Transmission Rates, which are as follows:

- $6.12/kW/Month Network Service Rate (a $0.34/kW increase)
- $0.95/kW/Month Line Connection Service Rate (no change)
- $3.21/kW/Month Transformation Connection Service Rate (no change)

Question(s):

a) Please update the RTSR work form to reflect the updated UTRs.
b) Please update the tariff and bill impact model accordingly.

8-Staff-65
Regulatory charges
Ref 1: Tariff and Bill Impact Model_API Version
Ref 2: OEB Letter: 2025 Inflation Parameters, June 20, 2024

Preamble:
On June 20, 2024 the OEB issued the 2025 inflation factor of 3.6% for electricity distributors.

Question(s):

a) Please update the regulatory charges in tariff and bill impact model to reflect the inflations factor of 3.6%.

8-Staff-66
Loss Factor
Ref 1: Chapter 2 Appendix 2-R
Ref 2: Exhibit 8, Table 17, p. 30

Preamble:
OEB staff notes distribution line losses have remained above 5% in the 5 historical years in reference 1.

Question(s):

a) Please explain why the actual purchased power in the load forecast model or that reported in RRR do not match either the higher or lower wholesale kWh Delivered to the Distributor values in reference 1.
b) Please explain why the distribution losses are higher than average in 2020.
c) Is Algoma Power considering a line loss study?

Exhibit 9 – Deferral & Variance Accounts

9-Staff-67
Echo River TS ACM
Ref 1: Exhibit 9, Table 9-11, page 31
Ref 2: Exhibit 2, Table 46, page 93
Ref 3: Exhibit 2, Table 45, page 91
Ref 4: Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (OEB ACM Report), September 18, 2014

Preamble:
In Reference 1, Algoma Power provides the incremental revenue requirement calculation for the Echo River TS ACM project based on the actual costs as well as a forecast for 2024.

Table 9-11 - IRR Calculation Echo River TS ACM Project

Incremental Revenue Requirement Based on Actual Costs Advanced Capital Module Echo River TS Project			2023A	2024F
ACM Fixed Assets				
Gross Fixed Assets - Opening			-	10,851,932
Additions			10,851,932	154,279
Gross Fixed Assets - Closing			10,851,932	11,006,211
Accumulated Depreciation/Amortization - Opening			-	(100,481)
Depreciation/Amortization Expense (Note 1)			(100,481)	(244,582)
Accumulated Depreciation/Amortization - Closing			(100,481)	(345,063)
Net Book Value - Opening			-	10,751,451
Net Book Value - Closing			10,751,451	10,661,148
Net Book Value - Average			5,375,726	10,706,300
Return on Rate Base				
	Deemed %	Rate		
Short Term Debt	4.00%	2.75%	5,913	11,777
Long Term Debt	56.00%	4.77%	143,596	285,987
			149,509	297,764
Return on Equity (ROE)	40.00%	8.52%	183,205	364,871
Return on Rate Base	100.00%	6.19%	332,714	662,635
Grossed-up Taxes/PILS				
Regulatory Taxable Income (ROE)			183,205	364,871
Add: Depreciation/Amortization Expense			100,481	244,582
Less: CCA (Note 3)			(868,155)	(811,044)
Incremental Taxable Income			(584,469)	(201,591)
		Rate		
Taxes/PILs Before Gross-Up		26.50%	(154,884)	(53,422)
Grossed-Up Taxes/PILs			(210,727)	(72,683)
Incremental Revenue Requirement (IRR)				
Return on Rate Base			332,714	662,635
Amortization Expense			100,481	244,582
Grossed-Up Taxes/PILs			(210,727)	(72,683)
IRR Total			222,468	834,534
Cumulative IRR			**222,468**	**1,057,002**
Note 1	Depreciation/Amortization based on in service month.			
Note 2	Original ACM modeling submitted assumed Year 1 CCA effective rate = 1x CCA rate and so that approach was taken in the calculation of IRR above. Remaining difference has been calculated for OEB 1592 DVA allocation purposes. Cumulatively, API will have passed the benefit of the enhanced CCA deductions through between a combination of the recalculated IRR and the OEB 1592 DVA forecasted amounts.			

Reference 2 outlines the in-service actual spending associated with each project in each year.

Table 46- ACM Project Spending – In-Service Timing

	SSM Facility	Notes	ERTS	Notes
Approved ACM Amounts	$ 12,690,000	2022 in-service	$ 7,500,000	2021 In-Service
Actual In-Service Additions	**SSM Facility**	**Notes**	**ERTS**	**Notes**
2022	$ 15,708,824	Building in-service, occupancy	$ -	
2023	$ 640,323	Close-out improvements, parking and driveway adjustments.	$ 10,906,211	Spare Transformer
2024	$ 200,622	Additional costs for severance and other items.	$ 100,000	Station Transformer Work
Actual In-Service Additions	**$ 16,549,769**		**$ 11,006,211**	
Adjust for IT Assets - see note	**$ 104,894**		**N/A**	
Total With Adjustment	**$ 16,654,663**			

Algoma Power provides a breakdown of the Echo River TS project budget and actual costs in Reference 3.

Table 45- ERTS Cost Breakdown

Cost Item	Budget	Total Actual Cost	Variance ($)
Cost payable to HOSSM/IESO	$7,500,000	$10,754,279	$3,254,279
API Internal Cost		$63,207	$63,207
Study Cost (for Alternative & Business Case		$181,111	$181,111
Modification required to API Wholesale Meter		$7,614	$7,614
Total	$7,500,000	$11,006,211	$3,506,211

Section 7.1.1 of the OEB ACM report states that,

> *The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In that report the Board determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IR plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the Price Cap IR plan term. The Board adopted this as a clarification to the policy on ICM in the Filing Requirements. This approach is unchanged for the new ACM/ICM policy.*

Question(s):

a) Please explain why the fixed assets additions for 2023 and 2024 reported in Reference 1 differ from the in-service additions for those years as reported in Reference 2. Please update the evidence as needed.

b) Please confirm in which year the Echo River TS was considered to be in service according to the Accounting Standards for Private Enterprises (ASPE).
   i. Did Algoma Power's external auditors of its financial statements agree on the capitalization of this asset in the year?
   ii. If not, why not?
c) Please explain in detail what Algoma Power internal cost and Study Cost outlined in Reference 3 entail.
   i. Please clarify which section of the ASPE allows for the inclusion of these types of costs as part of the capital asset cost.
d) Please confirm the total cost for the Echo River TS ACM project is to be included in the rate base based on the ASPE capitalization policy.
e) Please provide a fixed asset continuity schedule using the same format as Appendix 2-BA for the Echo River project by year, itemized by asset class.

9-Staff-68
SSM Facility ACM
Ref 1: Exhibit 9, Section 9.3.12, Pg. 26 - 32
Ref 2: Exhibit 2, Table 46, page 93
Ref 3: Appendix 2-BA

Preamble:
In Table 9-9 of Reference 1, Algoma Power provides the incremental revenue requirement calculation for the SSM facility ACM project. Additionally, Algoma Power states a pro-rata approach is used to allocate the capped amount of $12.69M by asset class based on the actual cost of $15.71M (used and useful in 2022) for depreciation expense and associated CCA deduction calculations.

Table 9-9 - IRR Calculation Sault Facility ACM Project

Incremental Revenue Requirement Based on Actual Costs Advanced Capital Module Sault Facility Project - Capped at $12,690,000			2022A	2023A	2024F
ACM Fixed Assets					
Gross Fixed Assets - Opening			-	12,690,000	12,690,000
Additions (Note 1)			12,690,000	-	-
Gross Fixed Assets - Closing			12,690,000	12,690,000	12,690,000
Accumulated Depreciation/Amortization - Opening			-	(21,550)	(280,151)
Depreciation/Amortization Expense (Note 2)			(21,550)	(258,601)	(258,601)
Accumulated Depreciation/Amortization - Closing			(21,550)	(280,151)	(538,752)
Net Book Value - Opening			-	12,668,450	12,409,849
Net Book Value - Closing			12,668,450	12,409,849	12,151,248
Net Book Value - Average			6,334,225	12,539,150	12,280,549
Return on Rate Base					
	Deemed %	Rate			
Short Term Debt	4.00%	2.75%	6,968	13,793	13,509
Long Term Debt	56.00%	4.77%	169,200	334,946	328,038
			176,168	348,739	341,547
Return on Equity (ROE)	40.00%	8.52%	215,870	427,334	418,521
Return on Rate Base	100.00%	6.19%	392,038	776,073	760,068
Grossed-up Taxes/PILS					
Regulatory Taxable Income (ROE)			215,870	427,334	418,521
Add: Depreciation/Amortization Expense			21,550	258,601	258,601
Less: CCA (Note 3)			(768,685)	(696,694)	(643,009)
Incremental Taxable Income			(531,265)	(10,759)	34,113
		Rate			
Taxes/PILs Before Gross-Up		26.50%	(140,785)	(2,851)	9,040
Grossed-Up Taxes/PILs			(191,544)	(3,879)	12,299
Incremental Revenue Requirement (IRR)					
Return on Rate Base			392,038	776,073	760,068
Amortization Expense			21,550	258,601	258,601
Grossed-Up Taxes/PILs			(191,544)	(3,879)	12,299
IRR Total			222,044	1,030,795	1,030,968
Cumulative IRR			**222,044**	**1,252,839**	**2,283,807**

Note 1 With $15,708,824 in costs used and useful in 2022, API used a pro-rata approach to allocate the capped amount of $12,690,000 by asset class for depreciation expense and associated CCA deduction calculations.

Note 2 Depreciation/Amortization based on in service month.

Note 3 Original ACM modeling submitted assumed Year 1 CCA effective rate = 1x CCA rate and so that approach was taken in the calculation of IRR above. Remaining difference has been calculated for OEB 1592 DVA allocation purposes. Cumulatively, API will have passed the benefit of the enhanced CCA deductions through between a combination of the recalculated IRR and the OEB 1592 DVA forecasted amounts.

Reference 2 outlines the in-service actual spending associated with each project in each year.

Table 46- ACM Project Spending – In-Service Timing

	SSM Facility	Notes	ERTS	Notes
Approved ACM Amounts	**$ 12,690,000**	**2022 in-service**	**$ 7,500,000**	**2021 In-Service**
Actual In-Service Additions	**SSM Facility**	**Notes**	**ERTS**	**Notes**
2022	$ 15,708,824	Building in-service, occupancy	$ -	
2023	$ 640,323	Close-out improvements, parking and driveway adjustments.	$ 10,906,211	Spare Transformer
2024	$ 200,622	Additional costs for severance and other items.	$ 100,000	Station Transformer Work
Actual In-Service Additions	**$ 16,549,769**		**$ 11,006,211**	
Adjust for IT Assets - see note	**$ 104,894**		**N/A**	
Total With Adjustment	**$ 16,654,663**			

Section 7.1.1 of the OEB ACM report states that,

> The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In that report the Board determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IR plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the Price Cap IR plan term.13 The Board adopted this as a clarification to the policy on ICM in the Filing Requirements. This approach is unchanged for the new ACM/ICM policy.

Question(s):

a) Please confirm in which year the SSM facility was considered to be in service according to the ASPE.
    i. Did Algoma Power's external auditors of its financial statements agree on the capitalization of this asset in the year?
    ii. If not, why not?
b) Please clarify why the land severance cost is considered as part of the total asset cost and provide the reference to the relevant section of ASPE.
c) Please confirm the total cost for the SSM Facility ACM project is to be included in the rate base based on the ASPE capitalization accounting policy.
d) Please provide a fixed asset continuity schedule using the same format as Appendix 2-BA for the SSM Facility ACM project by year, itemized by asset class, based on the actual project spending and capped amount.

9-Staff-69

ACM True-up CCA
Ref 1: Exhibit 9, Section 9.3.12, pages 26 - 32
Ref 2: 2025 Continuity Schedule
Ref 3: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, Section 2.2.8, pages 22-23

Preamble:
According to the 1592 PILs calculations outlined in Table 9-12 and Table 9-10 of Reference 1, OEB staff summarizes the CCA differences for both projects in the table below.

CCA Difference	2022	2023	2024
Echo River TS		(156,503)	12,520
SSM	(138,573)	12,978	9,678
Total	**(138,573)**	**(143,525)**	**22,198**
Accumulated Total	**(138,573.00)**	**(282,098.00)**	**(259,900.00)**

In Reference 3, the OEB provides guidance on the impacts of the accelerated capital cost allowance (CCA) related to the ACM/ICM true-up.

> The impacts of accelerated capital cost allowance (CCA)17 should not be reflected in an ACM revenue requirement proposal associated with these projects. The OEB will assess the impact of the accelerated CCA on all capital investments at the time of rebasing to minimize the complexity of the review. Distributors should include the impact of the CCA rule change associated with any ACM projects that are approved for ACM treatment in Account 1592 - PILs and Tax Variances – CCA Changes. Disposition of amounts tracked in the applicable Account 1592 CCA sub-account should be brought forward at the time of a distributor's next rebasing.

Question(s):

a) Please reconcile the CCA differences outlined in Reference 1 with the amounts reported in Reference 2 in Account 1592, Sub-Account PILs and Tax variance for 2006 and Subsequent Years, by year.
b) Please provide the CCA calculation for amounts recorded in Sub-Account PILs and Tax variance for 2006 and Subsequent Years, based on the actual cost for both ACM projects. These calculations should include:
    a) The undepreciated capital cost (UCC) continuity schedules for each year, itemized by CCA class.
    b) The calculated PILs/tax differences.

c) The grossed-up PILs/tax differences.
d) Any other applicable information.
e) Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable.
f) A reconciliation of these amounts to the amounts presented in the Account 1592 sub-account for CCA changes in the DVA continuity schedule.

c) Please provide a revised 2025 Continuity Schedule, if necessary.

9-Staff-70
DLI Rate Rider Recoveries
Ref 1: Exhibit 9, section 9.3.11, pages 24-25
Ref 2: 2025 Continuity Schedule

Preamble:
Table 9-5 in Reference 1 summarizes the differences in the DLI incremental revenue requirement calculations.

Table 9-5 - DLI Revenue Requirement

	2020 COS Submitted	Actual	Difference
Deferred and forecasted Incremental Revenue Requirement	273,697	209,779	(63,918)
Net Interest	10,265	8,993	(1,272)
Net Deferred Revenue Requirement	283,962	218,772	(65,190)

Table 9-6 in Reference 1 outlines the DLI rate rider recoveries compared to the actual revenue requirement.

Table 9-6 - DLI Rate Rider Recoveries

	2019	2020	2021	2022	2023	2024 Estimated	Cumulative Total	Actual Revenue Requirement	Difference (Over Collected)	# of Customers	Refund Rate Rider
DLI Rate Rider Recoveries	15,163	50,378	44,974	44,634	45,467	45,467	246,083	218,772	27,311	340	6.70

In Reference 1, Algoma Power proposes that “this remaining forecasted residual balance be disposed of on a final basis and that a one-year refund rate rider be provided to former DLI customers to return the excess rate riders collected to date.”

OEB staff notes the total claim amount for Account 1508, Sub-Account Dubreuilville Costs & Revenues is a credit balance of $65,190 according to Reference 2.

Question(s):

a) Please confirm whether the requested disposition amount related to the DLI revenue requirement is a credit amount of $27,311, resulting from the overcollection as calculated in Table 9-6.
   i. If so, please explain why the ending balance of the Sub-Account Dubreuilville in the 2025 Continuity Schedule does not match the over-collected amount of $27,211 and revise Reference 2 accordingly.
   ii. If not, please explain why.

9-Staff-71
Accounts 1588 and 1589
Ref 1: Exhibit 9, section 9.3.4, pages 20 -21
Ref 2: Electricity Act, section 36.1.1
Ref 3: 2025 GA Analysis Workform

Preamble:
In Reference 1, Algoma Power states:

> It appears the adjustments and payments it requires from the IESO in order to facilitate the disposition of accounts 1588 and 1589 for the years 2021 and 2022 fall outside the two-year limitation period imposed on the IESO under O. Reg. 153/23, which came into effect on July 1, 2023. Accordingly, API respectfully requests that, further to Sub-Section (7)(b), of Section 36.1.1 of the Electricity Act, the OEB issue an order requiring the IESO to:
> A) accept the proposed adjustments to API's Class A values for both May 2021 and January 2022 as set out in this application in furtherance of the final disposition of API's 1588 and 1589 variance accounts, and
> B) make payments to API in accordance with those adjustments so that API may dispose of those variance accounts on a final basis.
>
> API requests that this Order be contemplated in conjunction with API's request for approval of disposition of its Group 1 and 2 balances.

Sub-Section (7)(b) of Section 36.1.1 of the Electricity Act states that,

> (7) Despite subsection (1), the IESO shall not be restricted from making or receiving any payment or adjustment of any amount to or from a market participant, a consumer, an entity or a person in respect of an entitlement or a specified charge to which that subsection applies where such payment or adjustment results from,
>
> …
>
> (b) a decision, an order or a direction of the Board in respect of a variance account.

In Table 3 below, OEB staff summarizes the principal adjustments recorded in Accounts 1588 and 1589 related to the settlement true-up as reported in reference 3.

Table 3: Summary of Principal Adjustments Pertaining to the Order to the IESO

Principal Adjustments Reported in GA Analysis Workform	1588	1589	Settlement True-ups Subject to the Two-year Limitation
CT 148 Recalculated Settlement True-up for **2021**	(400,222)	61,135	**(339,087)**
CT 148 Recalculated Settlement True-up for **2022**	2,540	(21,657)	**(19,117)**
Total	**(397,682)**	**39,478**	**(358,204)**

OEB staff notes from the GA Analysis Workform that the above 2021 and 2022 adjustments for Accounts 1588 and 1589 have been reflected in the principal adjustments of the respective years on the DVA continuity schedule.

In Reference 1, Algoma Power further states that:

> *Given that API continues to review its 2023 1588/1589 activity and balances, it is not requesting disposition of 2023 activity for these accounts as part of the initial Application submission. If API is able to complete a timely internal review of the 2023 1588/1589 balances and is also able show that variances are within the +/-1% as required, it will consider bringing forward an updated disposition request within this proceeding for 2023 (in addition to 2021 and 2022 already requested). Alternatively, if the reconciliation work is not fully completed early on enough in the proceeding, API respectfully requests a deferral of the request of 2023 1588/1589 balances until an application is submitted for 2026 rates.*

Question(s):

a) Please clarify whether Algoma Power requested a resubmission to the IESO.
   i. If so, please provide details on when Algoma Power communicated with the IESO and IESO's response to Algoma Power's request.
   ii. If not, please explain why.
b) In Algoma Power's view, in order to get around the two year limitation period, must the order under section 36.1.1(7)(b) of the Electricity Act be directed to the IESO, or would a decision and rate order directed to Algoma Power be sufficient.
   i. Please provide a draft order in respect of the resettlement issue.
c) Please confirm the table compiled by OEB staff as above and revise the table as applicable.
d) Please explain why Algoma Power has considered the 2022 adjustment for a total of ($19,117) material.
e) Please confirm that the principal adjustments recorded in Accounts 1588 and 1589 are based on the assumption that the IESO resettles the adjustments for CT148 and refunds these adjustments to Algoma Power. If not, please clarify.
f) Please explain what Algoma Power intends to do with the principal adjustments if the OEB does not issue the requested order requiring the IESO to resettle. Under this scenario, please clarify if Algoma Power needs to write off the overcharged amount in its financial statements. If so, please provide the journal entries for the write off and please also quantify any impact on Algoma's return on equity.
g) Please fill out the impacts on Algoma Power and its customers in the table below.

	Scenario #1 – OEB makes the order as requested by Algoma Power		Scenario #2 – OEB does not make the order as requested by Algoma Power	
	Impact on Algoma Power	Impact on customers	Impact on Algoma Power	Impact on customers
Account 1588 (all customers)				
Account 1589 (Non-RPP customers)				

h) Please provide an update on the review of the 2023 activities.

9-Staff-72
Pole Attachment Variance
Ref 1: Exhibit 9, section 9.3.10, page 24
Ref 2: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, December 15, 2022, page 65
Ref 3: Accounting Guidance on Wireline Pole Attachment Charges, July 20, 2018, page 3

Preamble:
Algoma Power is requesting the disposition of Account 1508 – Pole Attachment Revenue Variance (debit balance of $296,246).

Section 2.9.1.7 of the Filing Requirements states that distributors are to provide a table showing the calculation of the account balance, showing at a minimum, the annual balance broken down by customer type, if applicable, and:

- the number of poles used in the calculation.
- the pole attachment charge incorporated in rates.
- the updated charge.

Question(s):

a) Please provide the information as noted in Section 2.9.1.7 of the Filing Requirement to support the Account 1508 – Pole Attachment Revenue variance balances requested in this application for disposition.

9-Staff-73
Generic Cloud DVA
Ref 1: EB-003-2023, Accounting Order, November 2, 2023
Ref 2: Cloud Computing Implementation Q&A Document, PDF, February 2024
Ref 3: EB-2024-0063, Notice, March 6, 2024

Preamble:
On November 2, 2023, the OEB issued the Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs (Cloud Computing Implementation Report). The Cloud Computing Implementation Report noted that the Cloud Computing Implementation Account is generally intended to record cloud computing implementation costs when utilities first transition from on-premise solutions to cloud computing. In February 2024, the OEB hosted a webinar and Q&A session related to

the Accounting Order for the establishment of a deferral account to record cloud computing arrangement implementation costs and issued a Q&A document.

On March 6, 2024, the OEB commenced a generic hearing (EB-2024-0063) on its own motion to consider the cost of capital and other matters, including those related to the OEB's Cloud Computing Deferral Account (e.g., what type of interest rate, if any, should apply to this deferral account).

Question(s):

a) Please confirm whether Algoma Power has considered cloud computing solutions in its rebasing term and whether any amounts have been included in its forecast.
b) If not confirmed, please explain why and Algoma Power's proposal to address its cloud solution implementation needs during its rebasing term.

9-Staff-74
GOCA Variance Account
Ref 1: The OEB's Decision and Order for Getting Ontario Connected Act Variance Account, October 31, 2023

Preamble:
On October 31, 2023, the OEB issued a decision and order EB-2023-0143 for the Getting Ontario Connected Act Variance Account (GOCA variance account). The decision states that:

The OEB notes that the GOCA variance account will only be available to a utility until the end of its current IRM period. The account is not available for utilities that have reflected Bill 93 in their most recent rebasing applications.

OEB staff notes from the DVA continuity schedule that the GOCA sub-account under Account 1508 does not have any amount claimed in this application.

Question(s):

a) Please confirm that the OM&A cost in the test year reflects the Bill 93 impact for the utility's locate cost.
b) If so, please confirm that the Account 1508 sub-account GOCA variance account is to be discontinued after this rebasing application and update the evidence accordingly.

c) If not, please provide the rationale why the Bill 93 impact is not reflected in the test year's OM&A cost.

9-Staff-75
Land Use Revenue Requirement Variance Account
Ref 1: Exhibit 9, section 9.4.1, pages 33-35
Ref 2: Exhibit 4, pages 37 – 40

Preamble:
In Reference 1, Algoma Power states that the forecasted $767,909 in the test year OM&A "will be the proposed 'baseline' against which any entries into the DVA will be assessed, ensuring that the net entries into the proposed account are clearly outside the base upon which rates were set. Algoma Power further states that "At this time API has limited certainty with respect to the land use payments to be incurred, therefore API expects the account balances will be material."

Additionally, Algoma Power states in Reference 2 that,

> *API cannot predict with accuracy the aggregate amount that it may have to pay to maintain these land rights. For planning purposes, however, the rights payments for the 2025 test year are budgeted to be $767,909 per year. This amount is based on continuing payments and the OM&A equivalent of the current revenue requirement estimate (subject to all of the uncertainty factors below) for negotiations with various entities.*

Algoma Power states that the 767,909 is based on continuing payments and the OM&A equivalent of the current revenue requirement estimate (subject to all of the uncertainty factors below) for negotiations with various entities. These factors are:

> 1. *Negotiated form of agreement will impact the accounting treatment for the agreement. API capitalizes easements and/or other permanent agreements, as well as the costs required to facilitate these costs. In the case of an easement form of agreement, API also typically incurs survey costs associated with the easement, which can be material in nature. Survey costs are part of the capitalized amount. API's preference is to arrange for permanent easements in order to have long-term price stability, as well as certainty regarding its ability to maintain its use of the lands in question, however some land owners/interest holders may not be willing or able to agree to a permanent arrangement with a one-time payment.*

2. *At this time, API is not able to accurately predict the cost levels associated with the negotiation outcomes.*
3. *API is unable to predict and control the timing and phasing of these payments over the test year and subsequent COS term. Different forms of agreement may also require a combination of ongoing and one-time costs, with the one-time implementation costs being related to such items as legal fees, up-front payments, and/or other expenses incurred during negotiations or included as requirements in the final agreements."*

Algoma Power notes that some of the test year OM&A payments "may ultimately take the form of capitalized one-time payments, which has the potential of reducing the annual revenue requirement associated with those agreements."

Question(s):

a) Please explain in detail why Algoma Power believes the materiality eligibility criterion is met, given the limited certainty regarding the land use payments to be incurred and the challenges in accurately predicting the baselined land cost embedded in the 2025 rates.
b) Given the level of uncertainty that is demonstrated by the factors listed by Algoma, please provide Algoma's thoughts on removing the $767,997 baseline land cost in the OM&A of the test year and use the deferral account to record the costs when they are incurred in the incentive period. Please provide the pros and cons of this approach as compared to the approach proposed by Algoma.
c) Please elaborate further on how the $767,997 is derived.
d) Please explain why Algoma Power has included some potential capital expenditures in the OM&A expenses.
e) Please confirm the land use payment amounts to be recorded in the requested new variance account will include both OM&A expenses and capital expenditures.
    i. If confirmed, please clarify that Algoma is to record the revenue requirement impact on the capital expenditure and the OM&A expense to be incurred in the requested DVA and the total amount is then compared to the $767,909 OM&A that is embedded in the test year's revenue requirement.
    ii. Please update the journal entries in the draft accounting order by separating the capital expenditure and OM&A
    iii. Please describe how and when the capital expenditures portion of the actual land use payments will be added to the rate base and provide the related journal entries.

iv. Please clarify that the requested DVA will be disposed of in the next cost of service application along with other Group 2 DVAs. If so, please explain why a separate rate rider is needed for this DVA.

v. Please provide a revised draft accounting order accordingly.

9-Staff-76
Defined Benefit Pension Plan Variance Account
Ref 1: Exhibit 9, Section 9.4.1, pages 36-37
Ref 2: Exhibit 4, pages 37 – 38
Ref 3: Report of the Ontario Energy Board, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (the OEB Report), EB-2015-0040, September 14, 2017

Preamble:
In Reference 1, Algoma Power proposes a Defined Benefit Pension Plan Variance Account to capture variances in the coming COS cycle. Algoma Power states that "API has based a portion of its Section 3461 pension expense forecasts on a forecast prepared by Mercer for API in February of 2024 for the 2025 test year. The forecast provided by Mercer is influenced by a discount rate assumption of 4.9%, which is higher than past historical trending. On this basis, API anticipates that the test year budgets for the Defined Benefit Pension Plan are relatively low, and the actual Defined Benefit pension costs will materially increase in future years of the COS (ex: 2026-2029), as discount rates will trend back in line with past historical levels."

Page 13 of Reference 3 states that, no set-aside mechanism is necessary for pensions at this time.

Question(s):

a) Please provide the rationale of the requested variance account, considering the guidance provided in the OEB Report of regulatory treatment of Pension and OPEB costs.
b) Has Algoma Power considered forecasting the pension expense for the 2025 Test Year based on a discount rate aligned with the past historical levels expected during the 2026-2029 term?

9-Staff-77
1508-Other Regulatory Assets – Pension and OPEBs Deferral and Variance Sub-Accounts
Ref 1: EB-2013-0368 and EB-2013-0369 Accounting Order

Ref 2: Exhibit 9, page 11
Ref 3: EB-2014-0055 Exhibit 1, Tab 1, Schedule 10, page 3 of 3

Preamble:
In Reference 1, the OEB directed Algoma Power to establish four Group 2 Accounts related to pension and other post-employment benefits costs that resulted from Algoma Power's adoption of Accounting Standards for Private Enterprises Section 3462 (which disallowed amortization to income of actuarial gains and losses), starting on January 1, 2013. These include two accounts for the transitional amounts upon adoption, as well as two accounts for the annual expense differences between Section 3462 and 3461 (3461, the standard that underpinned rates at the time, previously allowed certain actuarial gains/losses to be amortized to net income).

In Reference 2, Algoma Power states the following with respect to Account 1508 – Other Regulatory Assets – Pension Deferral Sub-Account:

> Due to the reasons outlined in the EB-2013-0368/EB-2013-0369 proceeding requesting the creation of these variance accounts, API is not requesting disposition of the balance of this Sub-Account in this proceeding.

The Accounting Order for the proceeding referred to above was approved as filed on January 9, 2014. In that Accounting Order, the following statements were made by the applicants:

"Disposition of the accounts is proposed to occur in a future cost of service proceeding and will be subject to the Board's prudence review. The proposed recovery through a rate rider will be based on the average remaining service lives of employees in each respective company…No carrying charges will be recorded on these accounts."

In the pre-filed evidence, under Exhibit 1, Tab 1, Schedule 10 (page 3 of 3) in API's subsequent 2015 Cost of Service application (EB-2014-0055), Algoma Power made the following statements:

"The 2014 Bridge and 2015 Test Year revenue requirement model was developed assuming Section 3461 utilizing the corridor method to smooth P&OPEB expenses. Therefore, within this Application, API is not seeking recovery of any transitional balances, nor is it requesting recovery of any variances calculated for 2013. Instead, API will continue to assess the balances within the established deferral and variance accounts and will look to seek disposition of these balances in a future proceeding."

Question(s):

a) Please confirm that the same approach has been utilized for the 2024 bridge and 2025 test years for estimating Pension and OPEB expenses (using the corridor method prescribed in the previous Section 3461 rules).
b) please elobarate on the reasons that Algoma Power does not request the disposition of the four sub-accounts that were established in EB-2013-0368/0369.
c) Please Algoma Power's thought of discontinuing these four sub-accounts. If not, please explain why not.