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

BY EMAIL

October 1, 2019

Christine E. Long
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Attention: Ms. Christine E. Long, Registrar

Dear Ms. Long:

Re: Algoma Power Inc. (Algoma Power)
Application for 2020 electricity distribution rates
OEB Staff Submission
Ontario Energy Board File Number: EB-2019-0019

In accordance with Procedural Order No. 1, please find attached OEB staff's submission on the settlement proposal in the above proceeding.

Yours truly,

Original Signed By

Birgit Armstrong
Project Advisor – Incentive Rate Setting & Regulatory Accounting

Encl.

ONTARIO ENERGY BOARD

STAFF SUBMISSION ON SETTLEMENT PROPOSAL

2020 ELECTRICITY DISTRIBUTION RATES

ALGOMA POWER INC.

EB-2019-0019

October 1, 2019

INTRODUCTION

Algoma Power Inc. (Algoma Power) is a wholly-owned subsidiary of FortisOntario Inc. Algoma Power serves an extended area 93 km east and 255 km north of the City of Sault Ste. Marie, covering approximately 14,200 km^2, which includes seven First Nation Reserves, 14 organized townships and a large number of unorganized townships.

Algoma Power serves approximately 13,238 customers. Algoma Power's residential and general service (R1) and industrial (R2) customers, which are deemed residential customers under Ontario Regulation (O. Reg) 442/01, pay rates below the cost of service. Rates for these customers are financially subsidized through the Distribution Rate Protection (DRP) under O. Reg 198/17, a First Nations Delivery Credit (FNDC) under O. Reg. 197/17 and/or the Rural and Remote Electricity Rate Protection (RRRP) fund under O. Reg 442/01. A significant portion of the Algoma Power's revenue requirement is funded through the RRRP.[1]

On April 4, 2019, the OEB issued a Decision and Order granting Dubreuil Lumber Inc. (DLI) leave to sell its distribution system to Algoma Power.[2] The transaction was closed on August 7, 2019 and an amended license was issued on August 13, 2019.

Algoma Power filed a cost of service application with the Ontario Energy Board (OEB) on May 17, 2019 seeking approval for changes to the rates that Algoma Power charges for electricity distribution, to be effective January 1, 2020.

The OEB issued an approved issues list for this proceeding on August 23, 2019. A settlement conference was held from August 28 – 29, 2019. The parties to the settlement proposal were Algoma Power, the School Energy Coalition and Vulnerable Energy Consumers Coalition (Parties). Algoma Power filed a settlement proposal setting out an agreement among all the Parties to the proceeding on September 24, 2019.

The settlement proposal represents a complete settlement of the issues in this proceeding.

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[1] Of the requested revenue requirement of $25,454,574, $14,342,179 or 56% will be funded through RRRP if approved.

[2] EB-2018-0271

For a typical residential customer with monthly consumption of 750 kWh, the total bill impacts under the filed settlement proposal would be an increase of $2.21 per month, before taxes or an increase of 1.8%. Under the RRRP program, base distribution rates for Algoma Power's residential, commercial and industrial customers are adjusted annually based on the average increase for all other electricity distributors in Ontario.

Algoma Power is also part of the DRP program, which caps the base distribution charge for certain residential customers for eight distributors in the province. This program has been in effect since July 2017 and the current monthly distribution charge is capped at $36.86.

This submission is based on the status of the record as of the filing of Algoma Power's settlement proposal and reflects observations which arise from OEB staff's review of the evidence and the settlement proposal. It is intended to assist the OEB in deciding upon Algoma Power's application and the settlement proposal.

Settlement Proposal

OEB staff has reviewed the settlement proposal in the context of the objectives of the *Renewed Regulatory Framework* (RRF)[3], the Handbook for Utility Rate Applications[4], other applicable OEB policies, relevant OEB decisions, and the OEB's statutory obligations. OEB staff is satisfied that the Parties considered the issues and outcomes of the RRF in the context of Algoma Power's application.

OEB staff further submits that the explanations and rationale provided by the Parties is adequate to support the settlement proposal and that the outcomes arising from the OEB's approval of the settlement proposal would adequately reflect the public interest and would result in just and reasonable rates for customers.

OEB staff will provide further specific submissions on the following issues, which are a subset of the issues listed in the settlement proposal:

- 1.1 Capital and 5.3, 5.4 and 5.5 Advance Capital Module (ACM)
- 1.2 Operating, Maintenance & Administration (OM&A)

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

- 2.1 & 2.2 Revenue Requirement
- 3.1 Load Forecast
- 3.3 Allocation of costs attributable to the Dubreuilville service area
- 3.5 RRRP funding
- 4.1 & 4.2 Accounting
- 4.3 Disposition of the Interim Licence Deferral Account (ILDA) and Transaction and Integration Cost Deferral Account (TICDA)
- 5.6 Effective date of January 1, 2020

1.1 Capital

Algoma Power proposed net capital additions of $8.73 million, which is a decrease of 1.57% from 2015 OEB-approved amounts. In the settlement proposal, the Parties agreed to net capital additions of $8.74 million for 2020. The variance of $8,038 is due to the agreement that Algoma Power will no longer amortize its pensions and other post-employment benefit (OPEB) related actuarial gains or losses in revenue requirement. This issue is discussed further under issue 4.1.

The Parties also agreed to a reduction in 2019 capital additions of $474,024 due to an updated forecast in DLI-related capital expenditures, of which a $250,000 related to the timing of engineering for the 2020 substation rebuild. This expenditure was added to the 2020 capital expenditures. With the updated 2019 capital additions and the agreed capital expenditures of $8.74 million for 2020, the settled 2020 test year rate base is $119.8 million.

In the context of the settlement proposal, OEB staff takes no issue with the 2020 capital expenditures and rate base amounts. Algoma Power has indicated that these amounts will be sufficient to enable the reliable operation of its system. OEB staff supports the proposed capital budget and rate base as outlined in the settlement proposal.

In addition to 2020 capital expenditures, the Parties agreed to a future funding commitment through an Advance Capital Module (ACM) for the following projects:

- 2021 Echo River Transformer Station (TS) – $7.5 million (capital contribution to Hydro One Sault Ste. Marie (HOSSM))
- 2022 Sault Ste. Marie Facility – $ 12.69 million

5.3 Echo River

As part of the settlement proposal, the Parties agreed to Algoma Power's ACM request regarding a second transformer at the Echo River TS, for $7.5 million. The proposed in-service date is 2021.

This project seeks to resolve issues with the contingency supply to Algoma Power's 34.5 kV system, east of Sault Ste. Marie, due to limitations on Algoma Power's NA1 feeder. The Parties agreed that a transmission solution would be the most appropriate solution. OEB staff takes no issue with the agreement.

OEB staff notes that at the time of this settlement proposal Algoma Power is still in negotiations with HOSSM regarding the final cost responsibility for this new transformer. This settlement proposal is based on the assumption that Algoma Power's cost for this project is based on a 100% capital contribution. The Parties agreed that the project is prudent subject to the condition that Algoma Power will provide a final cost estimate and business case, based on a detailed engineering study and cost estimate process by HOSSM, at the time of its next rebasing. At that time, Algoma Power must demonstrate that it considered the refined cost estimate and cost responsibility for the project in comparison to other reasonable alternatives prior to committing to having HOSSM proceed with the project.

The actual incremental revenue requirement associated with this project will be determined at the time of filing for cost recovery of this project.

OEB staff notes that the ACM policy affords an applicant the opportunity to establish the need and prudence of a future project, which in service date, falls within the five-year rate setting cycle of the current cost-based application. In this particular case, the Parties have agreed that need has been demonstrated but that Algoma Power will take on the risk of further supporting the particular alternative chosen at the time of rebasing.

OEB staff takes no issue with a later determination of prudence, subject to the reporting obligation and final prudence review detailed in the settlement proposal.

5.4 Sault Ste. Marie

The Parties agreed that the proposal for an ACM for a Sault Ste. Marie facility (head office, operation/shops and storage facility) of $12.69 million, with a proposed in-service date of 2022, is appropriate.

OEB staff notes, that the settlement proposal reduced the requested capital budget by $1.41 million (10%) from $14.1 million to $12.69 million. Algoma Power stated, in its application, that the lease on its existing facility is expiring and that the existing facility is no longer adequate. Algoma Power provided a detailed business case to resolve the issue. The study examined a status quo option, a lease option of a new facility, a Brownfield option as well as the chosen Greenfield option. OEB staff notes while this option is higher than the other options, Algoma Power's cost per square foot falls below some comparable facilities in Southern Ontario.[5] OEB staff submits that the criteria for need and prudence for this ACM project has been met.

The Parties agreed that the capital budget for this project will be capped at $12.69 million. If the actual capital expenditure exceeds this amount, Algoma Power will not be eligible to collect the additional capital at the time it applies for cost recovery during the Price Cap Incentive Rate-setting (IR) term. However, the Parties agreed that at the time of its next rebasing application, Algoma Power will have an opportunity to explain and justify the prudence of the exceeded capital budget.

Algoma Power is expected to support any variances from the forecast budget that was provided at the time of the ACM approval before any incremental amounts from what was forecasted could be considered for inclusion in rate base. OEB staff notes that the approach agreed to by Parties is a deviation from the ACM policy, which allows for applicants to seek incremental costs at the time of the ICM if it can demonstrate the prudence of the cost increases (subject to the 30% threshold). OEB staff does not oppose the delay in cost increase consideration to the next cost based application. In the context of this particular project, the Parties were of the view that a further incentive to control the capital budget was required.

5.5 ACM Funding Treatment

The OEB established the methodology for determining Algoma Power's funding mechanism in the 2007 proceeding.[6] This methodology gave effect to O.Reg.

[5] Waterloo North EB-2015-0108 and EB-2010-0144 and InnPower EB-2014-0086, using an inflation factor of 2% to escalate their costs to 2022 equivalency costs

[6] EB-2007-0744

442/01 titled “Rural or Remote Electricity Rate Protection” made under the *Ontario Energy Board Act*, 1998.

In its last rebasing Decision and Order[7], the OEB refined the methodology for calculating the RRRP funding. Included was the OEB’s finding that RRRP adjustments should be based on comparators’ base distribution rates and not take into account retail transmission rates, rate riders and rate adders.

As part of the settlement proposal, the Parties agreed to recovery of the ACM revenue requirement allocated to the RRRP-eligible classes (R1 and R2), during the IRM period, through a revenue requirement adjustment rather than a rate rider. This adjustment will not be subject to the annual adjustment by Algoma Power’s Price Cap IR factor.

This request constitutes a further refinement of the RRRP framework under which Algoma Power operates. The Parties noted that a rate rider cost recovery for a typical utility approximates what would have occurred had the investment been included in rate base in the test year and been subject to an annual base rate adjustment during the IRM period. In the case of Algoma Power, the majority of customers are eligible for rate protection under the RRRP and DRP programs. The settlement proposal notes that it is appropriate that Algoma Power’s ratepayers should receive the benefit of the RRRP and/or DRP for the capital related costs in the context of an ACM cost recovery. The Parties noted that it is the intent of the ACM policy to allow recovery of incremental revenue requirement during non-rebasing years with bill impacts that approximate a situation where the project costs had been included in base rates.[8]

OEB staff supports this proposal and is of the view that the agreed-upon funding mechanism reflects the spirit of the RRRP regulation as well as the spirit of the ACM policy. This funding methodology represents a simple and transparent approach to allow Algoma Power to smooth its capital spending and reflects manageable rate impacts over the long term.

1.2 OM&A

In the settlement proposal, the Parties agreed to a 2020 test year OM&A of $13.67 million, which represents an increase of $1.37 million (11.2%) over the 2015 OEB-approved OM&A of $12.30 million. This is an average increase of 2.24% per year over five years.

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[7] EB-2009-0278

[8] EB-2019-0019, Settlement Proposal p. 60

Through the interrogatory process Algoma Power adjusted its OM&A budget for the increased DLI-related costs, an update to Low-Income Energy Assistance Program costs and a reduction of intervenor costs for a total increase of $9,949.

As per the settlement proposal, the Parties agreed to a reduction to Algoma Power's OM&A budget as well as the reclassification of costs as follows:

- Reduction in OM&A of $450,000
- Increase in OM&A expenses due to the reclassification of $560,455 in shared Information Technology (IT) assets with an affiliate from other revenues to shared services
- Reduction of $123,553 due to a reclassification of DLI-related costs from OM&A expenses to a revenue requirement adjustment through other revenues

OEB staff submits that the reclassification of shared IT assets is appropriate. From 2015 to 2019 Algoma Power reflected these cost as a negative revenue offset in account 4380. As part of this settlement proposal, Algoma Power agreed to treat these cost as a shared service expense, which is reflected in its OM&A budget. OEB staff submits that this approach is appropriate and notes this reallocation represents a significant increase to the OM&A budget. However, OEB staff notes that this reclassification is revenue neutral since the corresponding amount was removed from the revenue offset account 4380.

OEB staff submits that the proposed 2020 test year OM&A expense of $13.68 million represents a reasonable increase from the 2015 OEB-approved OM&A budget and as stated in the settlement proposal; it will allow Algoma Power to maintain the safe and reliable operation of its distribution system.

2.1 & 2.2 Revenue Requirement

As outlined in Table 1 – Revenue Requirement Summary in the settlement proposal, the Parties have agreed to a service revenue requirement of $25.9 million and a base revenue requirement of $25.5 million. Algoma Power also included an updated Revenue Requirement Work Form (RRWF) to support the requested amounts. These amounts reflect a reduction of $448,292 to the base revenue requirement.

OEB staff notes that the changes to the revenue requirement are the result of the following factors:

- A revised opening rate base
- An addition of $8,038 to 2020 capital expenditures due to the agreement not to amortize actuarial gains or losses related to pensions and OPEB
- OM&A adjustments (see above)
- Other revenues reclassification

In the context of the settlement proposal, OEB staff supports the revenue requirement for the 2020 test year. OEB staff notes that the Parties have agreed to update the working capital allowance and cost of capital, using updated parameters for 2020 rates, during the draft rate order process.

3.1 Load Forecast

OEB staff supports the settlement of a load forecast of 227,437,704 kWh, which is a 1.1% increase over 2018 actuals and a customer forecast of 13,238, which is a 3.5% increase over 2018 actuals (due to the integration of Dubreuville customers) , as shown in Tables 12 and 13 of the settlement proposal.

The Parties agreed Algoma Power's methodology used for the load forecast, customer forecast, loss factors and Conservation and Demand Management adjustments is appropriate. As part of the settlement proposal, the Parties agreed to the following adjustment:

- Increase of 12.5 GWh in the 2020 load forecast for the R2 rate class

This change was a result of applying the decreasing trend from the regression only to the portion of the GS > 50 kW rate class excluding the five largest customers. This had the effect of increasing the forecast by approximately 2.5 GWh. Algoma Power also revised the forecast by 10 GWh to account for growth in the five largest customers.

OEB staff is of the view that these adjustment are reasonable.

3.3 Allocation of costs attributable to the Dubreuilville service area

In its application, Algoma Power proposed to allocate costs related to its newly acquired distribution system in the Dubreuilville service area directly to those customers.

As part of this settlement proposal, Algoma Power withdrew its proposal to directly allocate DLI-related costs to the R1 and R2 class; instead, the Parties agreed to allocate those costs in the manner prescribed by the OEB's cost allocation methodology. The impact of adding DLI-related costs to Algoma Power's overall cost structure is offset by the inclusion of DLI's customers to Algoma Power's customer base for the purpose of cost allocation, such that Algoma Power's customers outside of the Township of Dubreuilville, particularly in its Seasonal and Street Lighting rate classes, are not adversely affected by the inclusion of DLI-related costs.

OEB staff is of the view that the agreed-upon cost allocation methodology is in keeping with OEB policy and that a direct allocation would place an unnecessary administrative burden onto Algoma Power. In the context of the settlement proposal OEB staff supports the cost allocation methodology as appropriate.

4.1 & 4.2 Accounting

As per the settlement proposal, the Parties agreed to dispose of balances in its Group 1 (credit of $243,938) and Group 2 (debit of $275,045) Deferral and Variance Accounts (DVA) as of December 31, 2018 including forecasted interest through December 31, 2019. The Parties further agreed to dispose of 2018 balances and forecasted balances for 2019 in the following Group 2 account: Account 1508 – Pole Rental Revenue. This account will be closed as of December 31, 2019, and no further balances will be accumulated in this account.

On July 20, 2018, the OEB issued a letter to all rate-regulated licensed electricity distributors, advising them that the OEB is undertaking an initiative to standardize the accounting processes used by distributors relating to Regulated Price Plan (RPP) wholesale settlements. This letter also stated that, effective immediately, the OEB will not be approving Group 1 rate riders on a final basis pending the development of this further guidance.

On February 21, 2019, the OEB issued its Accounting Procedures Handbook Update - Accounting Guidance Related to Commodity Pass-Through Accounts

1588 & 1589, outlining standardized requirements for regulatory accounting and RPP settlements that all distributors are expected to follow (Accounting Guidance). The Accounting Guidance is effective January 1, 2019, and was to be implemented by August 31, 2019.

In the OEB's Addendum to Filing Requirements for Electricity Distribution Rate Applications – 2020 Rates (the 2020 Filing Requirements Addendum), under Section 3.2.5.3, the OEB stated that, for 2020 rate applications, distributors are to provide a status update on the implementation of the new Accounting Guidance, a review of historical balances, results of the review, and any adjustments made to account balances. The 2020 Filing Requirements Addendum also states the following expectations for final disposition requests of commodity pass-through account balances:

- Any historical balances that were previously approved on an interim basis, or not approved at all, including the 2018 balances, have been reviewed in the context of the Accounting Guidance and utilities are confident that there are no systemic issues with their RPP settlement and related accounting processes affecting those balances.

- Any historical balances that were previously not approved by the OEB due to concerns noted have been assessed in the context of the updated Accounting Guidance. Any necessary revisions or adjustments made are documented, discussed in detail, quantified, and provided to the OEB for review prior to request for final disposition.

In response to interrogatories, Algoma Power submitted that it was making best efforts to complete the review of its commodity account balances by the August 31, 2019 deadline.[9] Algoma Power has not requested final disposition of Group 1 balances since a detailed review was incomplete at the time of settlement.

OEB staff submits that it is appropriate to dispose of the 2018 Group 1 DVA balances on an interim basis and 2018 Group 2 DVA balances on a final basis.

OEB staff supports the proposed disposition of the forecasted balance in Account 1508 – Pole Rental Revenue. OEB staff submits that in the context of the settlement proposal, it is reasonable to dispose of this account on a forecast basis in this proceeding, rather than deferring disposition of amounts pertaining

[9] 9-Staff-70

to 2019 until Algoma Power’s subsequent rebasing application. OEB staff is of the view that the forecasted December 31, 2019 balance in this account is reasonable. OEB staff further submits that it is reasonable to close this accounts as of December 31, 2019, as any variances between forecast and actual results in these accounts are expected to be insignificant, given that the nature of the transactions in these accounts can be forecast with reasonably high accuracy.

Pension and OPEBs

In its application, Algoma Power proposed to recognize a portion of its accumulated actuarial gains/losses realized on its pension and OPEBs costs in the test period revenue requirement (calculated based on the corridor approach, under Accounting Standards for Private Enterprises (ASPE) 3461). The amounts recognized in the test period were calculated using the expected accumulated net actuarial losses (or gains) on pensions and OPEBs as of December 31, 2019. Under the corridor approach, the accumulated losses (or gains) that are in excess of 10% of the expected benefit obligation (i.e. the corridor) are amortized over the expected average remaining service life of active employees. For the 2020 test year, Algoma Power has recognized actuarial losses of $54,418 related to its pension, and actuarial gains of $76,700 related to its OPEBs. Both amounts are included within the 2020 test year values presented within Algoma Power’s application.[10]

Algoma Power agreed to change this approach and remove the amortization of actuarial gains/losses for the 2020 test year revenue requirement in order to align with how most other utilities in Ontario treat these costs for regulatory purposes. Currently, Algoma Power has two Group 2 accounts in place to track the difference between pension and OPEB costs measured under ASPE 3462 (where the full actuarial gain or loss is recognized in income) versus those measured under ASPE 3461. The Parties agreed that starting on the effective date of this proceeding Algoma Power will accumulate all actuarial gains/losses in these existing accounts: Account 1508 Other Regulatory Assets – Sub-Account – Pension Expense Variance and Account 1508 Other Regulatory Assets – Sub-Account Other Post-Employment Benefits Expense Variance.

As a result, capital expenditures in 2020 increased by $8,038 (included as an adjustment to Account 1830) and OM&A expenses increased by $14,244 (included as an adjustment to Account 5615).

[10] Interrogatory Response: 9-Staff-73, p. 118

OEB staff supports this approach as it essentially mirrors the approach that most utilities, particularly under International Financial Reporting Standards (IFRS), would use with respect to actuarial gains and losses.

4.3 Disposition of DLI-related costs

Algoma Power was appointed as the interim operator of the DLI distribution system on April 4, 2017 after DLI advised the OEB that it would no longer be able to continue to operate the system beyond April 27, 2017.[11]

In its recent Decision and Order,[12] the OEB approved the acquisition of DLI's distribution system by Algoma Power. Costs related to this transaction were tracked in two accounts, the Interim Licence Deferral Account (ILDA) (debit $1,048,148) and the Transaction and Integration Costs Deferral Account (TICDA) (debit $98,969).

As part of the mergers, acquisitions, amalgamations and divestitures proceeding, the OEB approved an interim, partial disposition of balances tracked in the ILDA to recover costs related to the depreciation and return on capital for the 2017-2019 period. This disposition resulted in an interim rate rider of $11.16/month over a period of six years, starting July 1, 2019. This rate rider is only applicable to customers in the Township of Dubreuilville and does not impact Algoma Power's legacy customers.

The Parties agreed to dispose of above balances as follows:

a) Continuation of a rate rider of $11.16/month until December 31, 2024 (applicable only to customers in the Township of Dubreuilville)
b) $433,282 – Inclusion of the undepreciated capital costs in Algoma Power's 2020 rate base (Gross additions of $453,221 minus depreciation $19,939)
c) $598,729 – Recovery of costs related to one-time events, transaction and integration cost over a five-year period from 2020 to 2024 through an annual adjustment to its base revenue requirement plus interest amount of $19,036 for a total of $617,765
    - Resulting in an annual adjustment of $123,553 ($617,765/5)

[11] EB-2017-0153

[12] EB-2018-0271

OEB staff notes that the disposition through a) continues to be on an interim basis. The settlement proposal notes that a request for final disposition of this account will be brought forward in the next rebasing application. Subject to that provision, OEB staff supports the disposition of costs attributable to customers in the Township of Dubreuilville as well as the inclusion of DLI assets into Algoma Power's rate base that are noted in part b) above. OEB staff submits that the quantum and cost recovery mechanism are appropriate.

OEB staff notes that the disposition of one-time events, transaction and integration costs in part c) is unique and unusual. Typically, Group 2 account balances are disposed of through a rate rider funding mechanism. In this case, the Parties agreed to dispose of the balance of $617,765 through an annual adjustment to Algoma Power's revenue requirement over a five-year period.

OEB staff notes the RRRP funding mechanism only considers the fixed monthly charge and variable distribution charges[13], without consideration for a rate rider, regardless of its nature. If a rate rider disposition were applied, the transaction and integration costs would fall outside of the RRRP framework. The Parties agreed that existing Algoma Power customers should be able to benefit from the RRRP and DRP framework for DLI-related transaction costs in order to avoid harm to its legacy customers.

OEB staff submits that the settlement proposal should be considered in this context. OEB staff is of the view that the proposed disposition through an annual revenue requirement adjustment is reasonable in light of Algoma Power's unique circumstances.

5.6 Effective date January 1, 2020

In the settlement proposal, the Parties agreed that an effective date of January 1, 2020 is appropriate. OEB staff notes that the complete settlement proposal was filed on September 24, 2019. OEB staff submits that an effective date of January 1, 2020 is appropriate.

All of which is respectfully submitted

[13] As determined in the OEB's Decision and Order EB-2009-0278, pp.5-8