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

Ontario

EB-2013-0110

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Algoma Power Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2014.

BEFORE: Marika Hare
Presiding Member

Allison Duff
Member

DECISION and ORDER

February 20, 2014

Algoma Power Inc. ("Algoma") filed an application with the Ontario Energy Board (the "Board") on August 16, 2013 under section 78 of the Act, seeking approval for changes to the rates that Algoma charges for electricity distribution, effective January 1, 2014 (the "Application") and includes the impact of the Rural or Remote Rate Protection ("RRRP") funding, pursuant to Ontario Regulation 442/01.

The Application met the Board's requirements as detailed in *the Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") dated October 18, 2012 and the *Filing Requirements for Electricity Distribution Rate Applications* dated July 17, 2013. Algoma selected the Price Cap Incentive Rate-Setting ("Price Cap IR") option to adjust its 2014 rates. The Price Cap IR methodology provides for a mechanistic and formulaic adjustment to distribution rates and charges in the period between cost of service applications. Algoma last appeared before the Board with a full cost of service application in the EB-2009-0278 proceeding.

The Board conducted a written hearing and Board staff participated in the proceeding. No letters of comment were received.

On October 28, 2013, Algoma filed supplemental evidence related to the assignment of the stretch factor used for its Price Cap IR calculation to adjust its 2014 rates. Following Board staff's submission regarding the supplemental evidence, Algoma filed a reply submission and Notice of Motion (the "Motion") requesting that the Board make provision for further interrogatories and written submissions on Algoma's supplemental evidence. The Board granted Algoma's Motion.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Incentive Regulation Mechanism and RRRP;
- Proposed Stretch Factor Reassignment;
- Rural or Remote Electricity Rate Protection Charge;
- Revenue-to-Cost Ratio Adjustments;
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates; and
- Review and Disposition of Group 1 Deferral and Variance Account Balances.

Incentive Regulation Mechanism and RRRP

Algoma's Application was filed on the basis of the Price Cap IR, modified to accommodate the requirements of the RRRP. Specifically, the setting of rates for Algoma's Residential R-1 and R-2 rate classes is subject to the RRRP Regulation, Ontario Regulation 442/01, section 4 subsections 3.1 and 3.2:

> (3.1) For each year, in respect of the rates for a distributor serving consumers described in paragraph 5 of section 2, the Board shall calculate the amount by which the distributor's forecasted revenue requirement for the year, as approved by the Board, exceeds the distributor's forecasted consumer revenues for the year, as approved by the Board. O. Reg. 335/07, s. 1 (2).
>
> (3.2) For the purpose of subsection (3.1), the distributor's forecasted consumer revenues for a year shall be based on the rate classes and on the rates set out

> for those classes in the most recent rate order made by the Board and shall be adjusted in line with the average, as calculated by the Board, of any adjustment to rates approved by the Board for other distributors for the same rate year. O. Reg. 335/07, s. 1 (2).

In its Decision on Algoma's most recent cost of service application (EB-2009-0278), the Board approved a methodology to calculate the RRRP adjustment to be applied to existing rates to generate the new base rates, (i.e. the Monthly Service Charge and the Distribution Variable Rate), for the R-1 and R-2 rate classes. The RRRP adjustment is based on the average annual change in distribution rates for all rate regulated distributors for the Residential and GS<50 kW customer rate classes. In its Application, Algoma used a RRRP Adjustment factor of 2.2% for the R-1 and R-2 rate classes which will be updated in the draft Rate Order for this proceeding.

Under an IRM regime, absent RRRP, a price cap adjustment index applies to the distributor's existing Board approved rates for all customer rate classes. In this case, the rates applicable to the R-1 and R-2 rate classes are to be adjusted by the RRRP adjustment only.

In its Decision on Algoma's 2012 IRM (EB-2011-0152), the Board enhanced the approved methodology to calculate the RRRP funding for the R-1 and R-2 rate classes during IRM years using the difference between:

i. The revenue requirement for the R-1 and R-2 rate classes adjusted by the price cap adjustment index; and
ii. The revenues generated by the R-1 and R-2 rate classes using the RRRP Adjustment.

The rates for all other customer classes not eligible for RRRP would be adjusted by the price cap adjustment index.

Board staff submitted that Algoma had calculated the rate adjustments in accordance with the Board's enhanced methodology. Furthermore, Board staff submitted an updated RRRP adjustment factor of 3.76%, which Algoma accepted in its reply submission.

The Board finds that Algoma has calculated the rate adjustments for the R-1, R-2, Seasonal and Street Lighting rate classes in accordance with the methodology approved in the EB-2011-0152 proceeding and approves the updated RRRP adjustment factor of 3.76%.

Proposed Stretch Factor Reassignment

The Board issued the *Report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (the "Price Cap IR Report") which provides the 2014 rate adjustment parameters for distribution companies selecting either the Price Cap IR or Annual IR Index option.

Distribution rates under the Price Cap IR option are adjusted by an inflation factor, less a productivity factor and a stretch factor. The inflation factor for 2014 rates is 1.7%. Based on the total cost benchmarking model developed by Pacific Economics Group Research, LLC (the "PEG model"), the Board determined that the appropriate value for the productivity factor is zero percent. The Board also determined that the stretch factor can range from 0.0% to 0.6% for distributors selecting the Price Cap IR option, assigned based on a distributor's cost evaluation ranking. In the Price Cap IR Report, the Board assigned Algoma a stretch factor of 0.6%.

As a result, the net price cap index adjustment for Algoma is 1.1% (i.e. 1.7% - (0% + 0.6 %)). Subject to the RRRP findings, the price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. The price cap index adjustment does not apply to the components of delivery rates set out in the list below.

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Electricity Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;

- microFit Charge; and
- Retail Service Charges.

Algoma is requesting that the Board assign the middle stretch factor of 0.3% for its 2014 rates, rather than the 0.6% assigned in the Price Cap IR Report as based on the PEG model.

Algoma stated that the PEG model did not accurately assess and compare the efficiency of Algoma within the general operating environment of distributors in Ontario. Algoma submitted that the estimated cost drivers used in PEG's analyses understate Algoma's predicted costs. Specifically, Algoma takes the position that the coefficients are not valid in its circumstances, as Algoma is an extreme outlier within the data set used by PEG to determine its coefficients.

Board staff indicated that this is Algoma's second request to the Board to alter its assigned stretch factor. In the Board's Decision setting Algoma's 2012 rates (EB-2011-0152), the Board denied Algoma's request for the mid-point stretch factor of 0.4% instead of the assigned 0.6%. In that proceeding Algoma referred to prior Board decisions and referred to itself as "high cost" and "low revenue" distributor, indicative of its special circumstances for measuring productivity. In its Decision the Board stated:

> To award a stretch factor that is different from that set out in the letter would have the effect of providing incremental relief to the utility for those qualities that are already appropriately dealt with via the RRRP mechanism. No incremental arguments were provided that would justify a different stretch factor. In any event, an IRM application is not an appropriate venue in which a change in stretch factors should be considered.

Board staff submitted that Algoma's arguments in its 2012 application are similar to those presented in this proceeding for 2014 rates. Board staff submitted that Algoma's analyses included in its interrogatory responses do not support the assignment of Algoma to the middle stretch factor of 0.3%. Rather, Board staff indicated that the PEG model predicts a distributor's costs based on its own historical actual data and the business condition variables faced by that distributor. As a result, Algoma's unique circumstances were factored into PEG's analysis.

Board staff submitted that Algoma chose the Price Cap IR method of the three rate-setting methods identified in the RRFE Report. If Algoma did not consider the Price Cap IR option compatible with its business needs, other rate setting options were available.

Finally, Board staff submitted that Algoma's stretch factor request was immaterial as the impact of applying a stretch factor of 0.6% versus 0.3% was $60,238, below the materiality threshold of approximately $106,000. Board staff submitted that Algoma would have to demonstrate it should be assigned the lowest stretch factor of 0.0% to exceed the materiality threshold.

In its reply, Algoma submitted the basis for its stretch factor request in this Application is completely different from its submissions in its 2012 EB-2012-0152 proceeding. In 2012, Algoma argued it was unique in terms of its high cost and low revenues and should not have its stretch factor based on a comparison to other distributors. In this Application, Algoma is submitting the PEG model is not responsive to its unique attributes. Algoma stated that while it is seeking the same relief in this proceeding, the bases for its submissions are different.

Algoma indicated that the materiality threshold did not apply to its stretch factor request in this proceeding; the threshold applied to Z factor and incremental capital module applications. However, Algoma indicated that the cumulative incremental difference in the stretch factor assignment would exceed the materiality threshold over time.

Finally, Algoma submitted that it did not have the option to purse alternative rate-making options to supports its business needs. Algoma indicated that it was bound by the Settlement Agreement approved by the Board in EB-2009-0278, and it did not have the choice to pursue an alternative to the Price Cap IR option.

Board Findings

The Board does not consider the circumstances in this proceeding to be similar to EB-2011-0152 when the Board denied Algoma's request for a change in stretch factor. In 2012, the Board indicated that an IRM application was not the appropriate venue to argue for a change in stretch factor. Since then, Board practice has changed. The Price Cap IR Report issued on November 27, 2013 specifically states that:

> During this consultation, some distributors wrote to the Board claiming extenuating circumstances that they believe should make them eligible for specific treatment in relation to stretch factor assignments. The Board believes that these requests should be addressed on a case-by-case basis.

The Board therefore finds that Algoma acted appropriately and responsibly in requesting the Board to review its stretch factor in this proceeding.

The Board agrees that Algoma is a unique distributor but the issue for the Board to decide in this proceeding is more specific. The issue is whether the parameters and coefficients of the PEG model, which establish the stretch factors, are appropriate for Algoma. To test this, an understanding of the model parameters and their applicability to Algoma is required.

Although the PEG model is based on data from all Ontario distributors, Algoma submits the five cost drivers are not representative of its unique attributes, namely:

1. number of customers served;
2. kWh deliveries;
3. system peak capacity;
4. average km of distribution over the sample period; and
5. percent of customers added in the last 10 years.

Algoma submitted that the coefficients or cost drivers in the PEG model are based on the industry average, and are not representative of Algoma which, it claims, is an outlier in the Ontario distribution industry. Algoma provided evidence to highlight differences in its service territory in interrogatory response 1-Staff-4s. The Board notes that during the PEG model consultation process on June 27, 2013, prior to the filing of this Application, Algoma notified the Board of its concerns with the PEG model and its applicability to Algoma.

In summary, Algoma submitted that the Board's assignment of the 0.6% stretch factor, as generated by the PEG model, would be inappropriate. In the absence of a reliable prediction of Algoma's costs, a reasonable compromise would be to start Algoma at the middle stretch factor of 0.3%.

Consistent with the Price Cap IR Report, the Board finds that Algoma's evidence illustrates that the PEG model, although applicable to the vast majority of distributors, may not apply to distributors that are particularly unique. The Board grants Algoma's request and assigns a stretch factor of 0.3% for the purpose of setting 2014 rates. The Board finds that assigning Algoma to the highest stretch factor of 0.6% would not be appropriate as the PEG model was designed to benchmark the whole distribution sector. Algoma has consistently argued that the PEG model does not fit its circumstances.

The Board disagrees with Board staff that Algoma could have pursued different rate making options for the 2014 rate year given its concerns with the applicability of the PEG model. First, Algoma felt bound by the Settlement Agreement approved by the Board in its last cost of service proceeding EB-2009-0278. Second, after the Board's Price Cap IR Report was issued on November 21, 2013, it was too late for Algoma to pursue other options and file with the Board in time for a January 1, 2014 implementation.

The Board does not consider the middle stretch factor assignment of 0.3% a "reasonable compromise". In addition, the Board does not intend to set a precedent by which Algoma can rely upon in future applications. In assigning the 0.3% for one year, the Board is providing Algoma with sufficient time to decide on the appropriate course of action for future incentive rate setting. As Algoma is scheduled to file a cost of service application in 2015 (or a 5-year custom incentive regulation plan), Algoma could avail itself of other rate making options with the expiry of its current Settlement Agreement. Algoma could file a different plan for 2015 or select the Price Cap IR option and accept the PEG model's updated stretch factor assignment. In general, if the PEG model does not apply to a distributor's circumstances, the Price Cap IR option is probably not a viable option.

The Board finds that the following Incentive Regulation Price Cap Metrics should be used to update Algoma's proposed 2014 distribution rates and 2014 RRRP funding amount.

- RRRP Adjustment Factor: 3.76%
- Price Escalator: 1.7%
- Stretch Factor: 0.3%
- Productivity Factor of 0.0%
- Price Cap Index (calculated): 1.4%

Rural or Remote Electricity Rate Protection Charge

The Board issued a Decision and Rate Order (EB-2013-0396) establishing the RRRP benefit and charge for 2014. The Board determined that the RRRP charge to be paid by all rate-regulated distributors and collected by the Independent Electricity System Operator ("IESO") shall be increased to $0.0013 per kWh effective May 1, 2014, from the current $0.0012 per kWh. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects the new RRRP charge.

Shared Tax Savings Adjustments

In its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors,* the Board determined that a 50/50 sharing of the impact of legislated tax changes between shareholders and ratepayers is appropriate. The tax reduction will be allocated to customer rate classes on the basis of the last Board approved cost of service distribution revenue.

The Application identified a total tax savings of $42,128 resulting in a shared amount of $21,064 to be refunded to rate payers.

The Board approves the disposition of the shared tax savings of $21,064 based on a volumetric rate rider using annualized consumption for all customer classes over a 10-month period from March 1, 2014 to December 31, 2014.

Retail Transmission Service Rates

Electricity distributors are charged for transmission costs at the wholesale level and then pass on these charges to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

The Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* which outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2014. The Board's guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new Uniform Transmission Rates ("UTR") levels and the revenues generated under existing RTSRs.

The Board issued its Rate Order for Hydro One Transmission (EB-2012-0031) which adjusted the UTRs effective January 1, 2014, as shown in the following table:

2014 Uniform Transmission Rates

Network Service Rate	$3.82 per kW
Connection Service Rates Line Connection Service Rate Transformation Connection Service Rate	 $0.82 per kW $1.98 per kW

The Board finds that these 2014 UTRs are to be incorporated into the filing module.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Algoma's 2012 actual year-end total balance for Group 1 accounts including interest projected to December 31, 2013 is a credit of $105,489. In its submission, Board staff noted that the principal amounts as of December 31, 2012 reconcile with the amounts reported as part of the *Reporting and Record-keeping Requirements*. As $105,489 results in a total credit claim of $0.0006 per kWh, it does not exceed the preset disposition threshold. Accordingly, Algoma did not seek disposition of balances in its Application.

The Board finds that no disposition of Group 1 balances is required at this time.

IMPLEMENTATION

The Board has made findings in this Decision and Order which change the 2014 distribution rates from those proposed by Algoma.

The Board expects Algoma to file a draft Rate Order, including a proposed Tariff of Rates and Charges and all relevant calculations showing the impact of this Decision and Order on Algoma's determination of the final rates. Supporting documentation shall include, but not be limited to, filing a completed version of the 2014 IRM Rate Generator model, updated rate design model and RTSR model.

A Rate Order will be issued after the steps set out below are completed.

THE BOARD ORDERS THAT:

1. Algoma shall file with the Board a draft Rate Order that includes revised models in Microsoft Excel format and a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision by February 28, 2014.

2. Board staff shall file any comments on the draft Rate Order including the revised models and proposed rates with the Board and forward to Algoma within 7 days of the date of filing of the draft Rate Order.

3. Algoma shall file with the Board responses to any comments on its draft Rate Order including the revised models and proposed rates within 4 days of the date of receipt of Board staff comments.

All filings to the Board must quote file number **EB-2013-0110,** be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/ and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, February 20, 2014
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary