Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2014-0055

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, 2015.

BEFORE: Ken Quesnelle
Presiding Member and Vice Chair

Allison Duff
Member

DECISION AND ORDER

January 8, 2015

Algoma Power Inc. (Algoma Power) filed a complete cost of service application (the Application) with the Ontario Energy Board (the Board) on May 12, 2014 under section 78 of the *Ontario Energy Board Act*, *1998* (the OEB Act), seeking approval for changes to the rates that Algoma Power charges for electricity distribution, to be effective January 1, 2015.

The Board declared Algoma Power's current rates interim, effective January 1, 2015.

Energy Probe Research Foundation (Energy Probe), the Vulnerable Energy Consumers Coalition (VECC) and the Algoma Coalition were intervenors in the proceeding.

A settlement conference was held. Algoma Power and the intervenors (the Parties) reached agreement on a number of issues (the Settlement Proposal). The Settlement Proposal was filed with the Board on October 10, 2014. Board staff participated in the settlement conference and supported the Settlement Proposal. After receiving the Settlement Proposal, the Board held an oral hearing on October 20, 2014 to hear the remaining three, unsettled issues.

At the conclusion of the oral hearing, the Board established dates for submissions from the Parties and Board staff.

While the Board has considered the entire record in this proceeding, it has made reference only to the evidence necessary to provide context to its findings. The issues dealt with in this Decision are the Settlement Proposal and the three, unsettled issues which were:

- Recovery of a Rural or Remote Electricity Rate Protection ("RRRP") funding variance from 2002 to 2007;
- Appropriate revenue-to-cost ratios; and
- Appropriate fixed/variable rate splits.

RRRP Funding Variance

Algoma Power seeks to recover a variance of $173,534 that acrrued between 2002 to 2007. During 2002 to 2007, Great Lakes Power Limited, Algoma's predecessor, was the distributor licenced to provide service to customers in the geographic area served by Algoma Power today. Algoma Power is asking the Board to allow it to recover the $173,534 from the RRRP variance account administred by Hydro One.

Electricity distributors in rural and remote service areas, such as Algoma Power, receive RRRP funding from a provincial account administered by Hydro One. The Board approves the funding amount such distributors receive from Hydro One and in turn, the distributor provides the RRRP credit amount to its RRRP eligible customers. From 2002 to 2007, the Board approved a fixed, monthly RRRP funding amount of $194,484 and a monthly customer credit of $28.50 for Great Lakes Power Limited.

RRRP funds are sourced from all distributors including those located in rural or remote service areas which have RRRP eligible customers. Hydro One records collections from distributors and also records payments made to distributors with RRRP eligible customers in a variance account[1]. Variance account balances result from differences between the inflow of collections and the outflow of payments.

Algoma Power indicated that the $173,534 variance, which it is claiming in this application, was related to two factors. First, its billing system allocated the $28.50 credit on a 30-day basis. During months with 31 days, the credits were issued for $29.45[2], or $1.05 higher than the Board approved amount. As a result, over the 2002 to 2007 period, customers were given credits exceeding the approved amount by $188,001.

Second, the number of eligible customers to receive the RRRP credit declined from 2002 to 2007. The RRRP payments received from Hydro One were based on a formula which assumed a fixed number of customers. The formula did not change based on the actual number of customers. As a result, over the 2002 to 2007 period, funding received from Hydro One exceeded payments made to customers by $14,467. The result of these two factors was a net overpayment to customers of $173,534.

Algoma Power clarified that it is not seeking a rate order from the Board to recover the RRRP variance. Algoma Power claims that the circumstances differ from those in which a cost that forms part of the revenue requirement is typically recovered. To recover the variance, Algoma Power is seeking a determination from the Board that it is "entitled to be compensated for the $173,534 in lost revenues for which it received no compensation". Algoma Power indicated that the basis for its entitlement to compensation is subsection 79(3) of the OEB Act which indicates that "a distributor is entitled to be compensated for lost revenue resulting from a rate reduction provided under subsection (1)".

Algoma Power further submitted that the Board has a great deal of discretion to determine whether a cost is recoverable when setting rates under section 78 of the OEB Act, and the Board is required by law to comply with subsection 79(3) of the OEB Act.

Board staff submitted that Algoma Power is not entitled to the variance as proposed. Board staff indicated that under section 79(3) of the OEB Act, a distributor is only

[1] Account 1508 (Other Regulatory Assets: Sub-Account RRRP Variance)
[2] (31/30 * $28.50 = $29.45)

entitled to compensation for the rate protection credit approved by the Board pursuant to section 79(1), not the credit amount actually given to customers. Board staff also submitted that Algoma Power is seeking compensation many years after the variance occurred. The rates from 2002 to 2007 were established under final rate orders which may not be varied, and no deferral or variance account was established for RRRP credits provided to customers.

Board staff submitted that Algoma Power's request could result in retroactive or retrospective rates as it is effectively seeking to adjust the $28.50 monthly credit to be $29.45 in months with 31 days. Board staff indicated that if Algoma Power was compensated from Hydro One's variance account, it would likely result in distributors prospectively collecting $173,534 more from consumers in other service areas to fund the variance.

The Algoma Coalition submitted that rates were final and there were no exceptions to allow Algoma Power to recover the under-compensation. Recovery at this late date would amount to "impermissable" retroactive ratemaking. The Algoma Coalition also submitted that this proceeding is not the correct forum to determine this issue. As Hydro One was not a party to this proceeding and was not able to make representations on its behalf, "it is trite law that an organization that is not a party to a proceeding cannnot be bound by an order resulting therefrom."

Energy Probe submited that Algoma Power has a variance of $188,001 because it gave back too much money based on the assumption and use of a 30-day per month proration of the $28.50. The correct billing approach would have ensured customers were given credits equal to the payments received from Hydro One. There would have been no variance associated with the proration of days. Energy Probe submitted that the Board should deny the request to recover the funding variance which resulted from a calculation error or oversight on behalf of Algoma Power.

VECC submitted that without the appropriate regulatory variance account in place before or during the event from 2002 to 2007, the Board cannot, as a matter of law, order Hydro One to make a payment for the past amounts claimed by Algoma Power. VECC argued that Algoma Power is "under the impression" that there exists an approved regulatory account for the purpose of this variance based on an email response from Hydro One [3]. As Hydro One is not a party to this proceeding, its views on the relief required based on the facts presented in this proceeding are unknown. VECC indicated that if the Board approved the payment to Algoma Power, the recovery would be collected ultimately from other Ontario ratepayers who cannot be charged retoractively for errors of this distributor.

VECC also submitted that Algoma Power is simply too late to claim a purported variance that occurred seven years ago. VECC indicated that Great Lakes Power Limited had an obligation to regularly true-up variances in the monthly fixed credit such that bill proration would not systematically over or under charge its customers.

In reply argument, Algoma Power submitted that its method of allocating the RRRP credit was appropriate. If the credit had been allocated on a 31-day basis, it would have resulted in credits less than $28.50 in months with less than 31 days.

Algoma Power indicated that even if it had made an error, which it did not, it is still entitled to compensation under subsection 79(3) of the OEB Act, as the OEB Act does not include an exception to subsection 79(3) for errors. Algoma Power further noted that distributors are, without exception, entitled to be compensated for lost revenues resulting from RRRP rate reductions.

Algoma Power also submitted that it does not need to have its own Board-approved deferral or variance account to record its under-compensation as it is not seeking rate recovery. The source of Algoma Power's entitlement to compensation is subsection 79(3) of the OEB Act. Algoma Power's legislative entitlement to compensation, along with Hydro One's RRRP variance account, have existed since 2002.

Algoma Power further submitted that because it is not seeking a rate to recover its compensation for lost revenues associated with RRRP, all retroactive ratemaking arguments put forward by Board staff and intervenors are outside the scope of this proceeding. Algoma Power indicated that it is not asking the Board to effectively amend its 2002 rate order or any other final rate order.

In reply argument, Algoma Power submitted that the Algoma Coalition's position was incorrect in that Hydro One should be a party to this proceeding as it is the source for the recovery. Algoma Power indicated that Hydro One simply administers the RRRP

[3] Undertaking No. J1.5 from Oral Hearing

variance account, which is funded by all ratepayers in Ontario. Hydro One neither has a financial interest in the funds that go into or out of the variance account, nor has the responsibility for any variances that arise.

Board Findings

The Board will not provide Algoma Power with a determination that recovery from Hydro One's RRRP variance account is appropriate. Algoma Power submits that the Board is required by law to comply with subsection 79(3) of the OEB Act and therefore a trueing-up of any variances must be implemented. The Board is satisfied that the intent of section 79(3) of the OEB Act can be met without the true–up of the variances as proposed by Algoma Power.

"Compensation for lost revenue resulting from the rate reduction provided under subsection (1)" refers to the mechanics of ensuring RRRP distributors receive payments in order to fund the customer credits. Subsection (1) indicates that the Board "shall provide rate protection for those customers or prescribed classes of customers by reducing the rates that would otherwise apply". Compensation in the context of subsection 79(1) and 79(3) is the compensation to fund the credits provided to RRRP customers. The Board acknowledges that the clearance of variances for a RRRP distributor is not explicitly provided for in sections 79(1) and 79(3) of the OEB Act. The Board finds that the legislation does not require a clearance of Algoma Power's variances. The Board considers it to have the discretion to deteremine whether Algoma Power's variances are trued-up or not.

Algoma Power's current mechanism, after 2007, applying sections 79(1) and 79(3) of the OEB Act does not include a true-up feature. The rate protection provided to its eligible customers in compliance with section 79(1) is accomplished by treating the funding amount (compensation) it recieves as an offset to its projected revenue requirement in the setting of rates. Any variances that result between expected revenues and actual are dealt with in accordance with normal regulatory pratice.

Customer numbers are the billing determinants for many rates in a Board-approved rate order. Variances occur and are absorbed; a standard regulatory risk for a distributor with rates established on a forward test year basis. There is nothing apparent with respect to the uniqueness of the RRRP credit of $28.50 per customer or the wording of section 79(3) to indicate that a true-up for variances in customer numbers is required.

The variance due to changes in customer numbers was just one of the two factors comprising the $173,534 variance, yet the true-up principle is the same for the billing proration variance.

The Board notes that the $28.50 credit was a fixed monthly amount. The payment from Hydro One of $194,484 was also a fixed amount. In 2002, no one would have expected the number of customers to remain flat without change over time, yet no variance account was established for the RRRP distributor.

The Board further notes that Hydro One's variance account was established for the purpose of administering the collection and dispersion of RRRP funding. In establishing the RRRP charges, the Board takes into account the balances in the relevant variance account. All rates, by which RRRP funds are collected, are variable based on a per kilowatt hour of electricity withdrawn from the IESO-controlled grid.

The Board acknowledges that Hydro One was not a party to this proceeding and the evidence regarding the operation of the variance account in the time period in question may not be complete. It is not possible to rule on the question of whether Algoma Power's proposal would result in retroactive ratemaking without a full understanding of the operation of the account in the time period in question. The Board finds that in the absense of any evidence to the contrary, it is appropriate to apply the same approach to the application of section 79 as exists today.

Revenue-to-Cost Ratios

Algoma Power has proposed revenue-to-cost ratios for each of its classes as follows:

Table 1
Revenue-to-Cost Ratios

Customer Class	Proposed "status quo" ratios 2015	Previously approved ratios 2011	Filing Guideline ranges[4]
Residential – R1	111.63 %	114.10 %	85 – 115 %
Residential - R2	111.71 %	59.80 %	80 – 120 %
Seasonal	54.97 %	115.00 %	85 – 115 %
Street Lighting	25.04 %	43.00 %	70 – 120 %

The issue of revenue-to-cost ratios for Algoma Power differs in scope from those of other distributors as a consequence of its eligibility for the RRRP. Unlike other distributors, any distribution rate increase for Algoma Power's R1 and R2 classes is capped by regulation at the provincial average rate increase (the RRRP Adjustment Factor). Any remaining cost from Algoma Power's R1 and R2 classes is collected through the RRRP. In addition, if the Seasonal and Street Lighting rate classes have ratios lower than 100%, the difference is also collected from all Ontario electricity customers who fund RRRP.

Algoma Power reported several issues with the Board's revenue-to-cost ratio model given its unique customer density and system configuration. Algoma Power submitted that individual rate classes may not have the appropriate level of allocated costs and the use of its 2011 cost allocation to underpin revenue-to-cost ratios "is somewhat misleading". As a result, Algoma Power proposed that the Board allow for one year's grace to work with Board staff and intervenors to reconfigure its cost allocation methodology in time for its 2016 incentive rate making (IRM) application. Until 2016, Algoma proposed "status quo ratios", or ratios that result from increasing current rates sufficient to recover the revenue deficiency[5].

[4] EB-2010-0219: Report of the Board - Review of Electricity Distribution Cost Allocation Policy
[5] Revenue Deficiency = Current Revenue Requirement less Revenue Recovery at Existing Rates

Board staff indicated that Algoma Power's proposal to decrease the Seasonal and Street Lighting ratios further from the ranges in the Filing Guidelines is not supportable even if uncertainty exists regarding allocated costs. Board staff submitted that the revenue-to-cost ratios for these two classes should be increased gradually over the course of the IRM period to reach the lower end of their respective ranges.

Board staff expressed concern with Algoma Power's proposal to include a new cost allocation study with its 2016 IRM application. Board staff submitted that the IRM process is not designed to accommodate an update of cost allocation and rate design unless previously approved by the Board. Rather, the current cost of service application is the appropriate place for Algoma Power to establish revenue-to-cost ratios to apply in the IRM term.

The Algoma Coalition submitted that as Algoma Power's distribution system was unique, it should be granted the ability to maintain status quo revenue-to-cost ratios for 2015.

Energy Probe had concerns with Algoma Power's request for one year's grace as there was no guarantee a comprehensive study could be completed in time for the 2016 rates application. Energy Probe submitted that the Board should direct Algoma Power to increase the ratios for the Seasonal and Street Lighting classes sufficient to reach a 10% total bill impact each year from 2016 to 2019 in order to raise the ratios closer to the ranges in the Filing Guidelines. Energy Probe supported its submission with the fact that Algoma Power's witness did not anticipate any cost allocation changes that would affect the Street Lighting ratio in a material way.

VECC supported Algoma Coalition's proposal to review cost allocation and file its study with the 2016 rate application. However, VECC submitted that for 2015, the Board should establish a preliminary pattern for future Seasonal and Street Lighting ratios during the IRM period to reach the lower end of the ranges in the Filing Guidelines. Specifically, the Board should direct Algoma Power to increase the Seasonal ratio to 60% and maintain the proposed Street Lighting ratio of 25.04%. In the absence of any further direction from the Board in future proceedings, the Board should increase the ratios as follows:

Table 2
Proposed Revenue-to-Cost Ratios in subsequent IRM period

	2015	2016	2017	2018	2019
Seasonal	60%	66%	72%	78%	85%
Street Lighting	25.04%	10% Bill Impact			

In reply argument, Algoma Power indicated VECC and Energy Probe's submissions were similar and reasonable. Algoma Power revised its proposed ratios according to those in Table 2.

Board Findings

The Board approves Algoma Power's revised proposed ratios from 2015 to 2019 as the class-specific ratios gradually increase toward the ranges in the Filing Guidelines. As this is a cost of service proceeding, the Board finds it necessary to establish a plan for the subsequent IRM period until a new cost allocation study is available. Any subsequent Board findings as a result of the study would supercede the annual ratios approved in this Decision.

The Board agrees with Board staff that it would not be appropriate for Algoma Power to include a new cost allocation study as part of an IRM application. The IRM process is designed to be streamlined, based on a mechanistic formula. Algoma Power is encouraged to proceed with its cost allocation study given its unique service area and to involve the intervenors and Board staff in the process. Algoma Power should consider and propose the appropriate form of application to enable a Board review of any new cost allocation and rate design proposals.

Fixed/Variable Rate Splits

Algoma Power proposed to increase the fixed and variable charges for its R1 class by the RRRP Adjustment Factor, thereby maintaining the current fixed-variable split. For its R2 class, Algoma Power proposes to maintain the monthly service charge at $596.12 throughout the subsequent IRM period. For the Seasonal and Street Lighting classes, Algoma Power proposed to maintain the monthly service charge at the 2014 approved amount of $26.75 and $0.98, respectively.

Algoma Power submitted that its rate design proposals are consistent with the approach agreed to in its previous cost of service application (EB-2009-0278) and used throughout the intervening IRM period from 2012 to 2014. For the Seasonal class, Algoma Power indicated that a conscious effort was made to limit increases in the fixed monthly service charge while allowing increases to the variable volumetric component. Algoma Power explained the rationale was to give individual consumers more ability to influence their overall costs. For the Street Lighting class, Algoma Power noted that there was no fixed component to the rate prior to EB-2009-0278.

The Algoma Coalition asked the Board to consider the unique attributes of Algoma Power as a distributor in northern Ontario in making its determination with respect to fixed-variable splits and to limit increases to fixed monthly service charges. Energy Probe and VECC supported Algoma's proposed increases to the R1 fixed and variable rates. Energy Probe took issue with the R2 proposal to maintain the current R2 fixed rate. Energy Probe submitted that the R1 and R2 rates should be set on the same basis and both the fixed and variable rates should be increased by the RRRP Adjustment Factor.

With respect to the Seasonal and Street Lighting classes, Energy Probe and VECC both submitted that the Board should direct Algoma Power to increase its rates to maintain the current fixed-variable splits. Both intervenors indicated that Algoma Power's proposal to maintain current, fixed service charges necessarily increases the variable charges for these rate classes. As a result, low-volume customers receive a decrease and high-volume customers receive an increase in their total bills.

Board staff made no submissions regarding the proposed fixed-variable rate splits.

In reply submission, Algoma Power agreed that Energy Probe's submission may be the more equitable solution for customers within the R2 class and revised its proposal to increase the fixed and variable charges by the RRRP Adjustment Factor.

With respect to the Seasonal and Street Lighting classes, Algoma Power maintained its proposals and made no further submissions.

Board Findings

The Board finds that fixed and variable rates for the R1 and R2 classes should be increased by the RRRP Adjustment Factor for 2015. As both R1 and R2 receive the RRRP adjustment, it is appropriate that both rate classes receive increases commensurate with the average increase for non-RRRP eligible customers in Ontario. The Board-approved RRRP Adjustment Factor for 2015 is 0.79% as indicated in a letter to Algoma Power dated October 4, 2014.

The Board finds it appropriate to maintain the current fixed-variable rate splits in 2015 for the Seasonal and Street Lighting classes. The Board does not agree that test year rate design should be based on previous settlement considerations and negotiations, especially given a potential four year subsequent IRM period. In addition, the Board does not support maintaining fixed rates at current levels as a means to lower total bills for low-volume Seasonal and Street Lighting customers. The Board directs Algoma Power to maintain the current fixed-variable splits for the Seasonal and Street Lighting rate classes until a new cost allocation study is complete and rate designs are proposed.

Settlement Proposal

The Board commends the Parties on reaching a settlement on most of the issues. Having reviewed the Settlement Proposal, and given its findings regarding the three unsettled issues, the Board accepts the Settlement Proposal in its entirety and accepts the combined rate effects as reasonable. A copy is attached as Appendix A.

The Board reminds the parties that, since settlements are the result of negotiations on numerous interconnected and sometimes complex issues, the terms of a settled issue in one proceeding may not necessarily be accepted by the Board in other proceedings.

Implementation

The Board directs Algoma Power to file a Draft Rate Order complete with detailed supporting material, including all relevant calculations showing the allocation of the revenue requirements from the Settlement Proposal to the classes, the determination of final rates and all approved rate riders, including bill impacts, and a calculation showing reconciliation of the total revenues by class to the revenue requirements. Supporting documentation shall include, but not be limited to, the filing of completed versions of the Revenue Requirement Work Form Excel spreadsheet, and the Cost Allocation Excel spreadsheet reflecting the Board's findings. Details of the revenue-to-cost ratios and the fixed variable splits are also to be included.

The Board approves a January 1, 2015 effective date and a February 1, 2015 implementation date for new rates. As the Board's final Rate Order will not be issued until after the effective date of January 1, 2015, Algoma Power's rates have been declared interim[6] effective January 1, 2015. The Board directs Algoma Power to include in its filing a foregone revenue rate rider related to January 2015.

THE BOARD ORDERS THAT:

1. Algoma Power shall file with the Board, and shall also forward to intervenors, 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 no later than **11 days** from date of issuance of this Decision and Order.

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

3. Algoma Power shall file with the Board and forward to intervenors 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 and/or intervenors' comments.

Cost Awards

The Board will issue a separate decision on cost awards once the following steps are completed:

1. Intervenors shall file with the Board and forward to Algoma Power their respective cost claim no later than **7days** from the date of the issuance of the final Rate Order.

[6] Interim Rate Order and Procedural Order No.3, issued October 16, 2014

2. Algoma Power shall file with the Board, and shall forward to intervenors within **17 days** from the date of issuance of the final Rate Order any objections to the claimed costs.

3. Intervenors shall file with the Board and forward to Algoma Power any responses to any objections for cost claims within **24 days** from the date of issuance of the final Rate Order.

4. Algoma Power shall pay the Board's cost incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote the file number, EB-2014-0055, 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 http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. 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 7 paper copies.

DATED at Toronto, **January 8, 2015**

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A

TO DECISION AND ORDER

EB-2014-0055

ALGOMA POWER INC.

DATED JANUARY 8, 2015

Settlement Proposal

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, 2015.

EB-2014-0055

Algoma Power Inc.

Settlement Proposal

October 10, 2014

This settlement proposal (the “Settlement Proposal”) is for the consideration of the Ontario Energy Board (the “Board”) in its determination of the rate application by Algoma Power Inc. (“Algoma Power” or “API”) for 2015 electricity distribution rates.

INTRODUCTION

Algoma Power filed an application with the Board on May 12, 2014 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B), seeking approval for changes to the rates that Algoma Power charges for electricity distribution, to be effective January 1, 2015 (the “Application”). The Board assigned the Application File Number EB-2014-0055.

Three parties requested and were granted intervenor status: Energy Probe Research Foundation (“Energy Probe” or “EP”); the Vulnerable Energy Consumers Coalition (“VECC”); and the Algoma Coalition (the "Coalition" or "Algoma Coalition"). These parties are referred to collectively as the “Intervenors”.

In Procedural Order No. 1, issued on June30, 2014, the Board approved the Intervenors in this proceeding and made its determination regarding the cost eligibility of the Intervenors.

In Procedural Order No. 2, issued on July 10, 2014, the Board set out dates for interrogatories (July 21 and 22, 2014), interrogatory responses (August 7, 2014), a Technical Conference (August 20, 2014), and a Settlement Conference (September 8-9, 2014).

Subsequent to the Technical Conference, parties conferred on and agreed to a proposed issues list for the Board's consideration. On August 28, 2014, the Board issued a decision in which it approved the proposed issues list (the "Issues List"), which is at Attachment "A" to this Settlement Proposal.

The Settlement Conference was duly convened in accordance with Procedural Order No.2 with Ms. Gail Morrison as facilitator. The Settlement Conference lasted longer than the Board's prescribed dates and concluded on October 8, 2014.

Algoma Power and the following Intervenors participated in the Settlement Conference (collectively the "Parties"):

- the Coalition
- Energy Probe
- VECC

The role adopted by Board Staff in the Settlement Conference is set out on page 5 of the Board's Settlement Conference Guidelines (the "Guidelines"). Although Board Staff is not a party to this Proposal, as noted in the Guidelines, the Board Staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Guidelines. The Parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the proposed settlement of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this settlement proposal.

SETTLEMENT PROPOSAL

This Settlement Proposal represents a partial settlement of the issues, in that some cases have been completely settled, while three issues remain unsettled. It is acknowledged and agreed that none of the Parties will withdraw from this Settlement Proposal under any circumstances, except as provided under Rule 32.05 of the Board's Rules of Practice and Procedure.

The Parties explicitly request that the Board consider and accept this Settlement Proposal as a package. None of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Settlement Proposal. The distinct issues addressed in this proposal are intricately interrelated, and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this Settlement Proposal which may be unacceptable to one or more of the Parties. If the Board does not accept the Settlement Proposal in its entirety, then there is no settlement unless the Parties agree in writing that those portions of the Settlement Proposal that the Board does accept may continue as a valid settlement, subject to any revisions that may be agreed upon by the Parties.

In the event that the Board directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties must agree with any revised Settlement Proposal prior to its resubmission to the Board for its review and consideration as a basis for making a decision.

Unless otherwise expressly stated in this Settlement Proposal, the agreement by the Parties to the settlement of each issue shall be interpreted as being for the purpose of settlement only and not a statement of principle applicable in any other situation. Where, if at all, the Parties have agreed that a particular principle should be applicable generally, this Settlement Proposal so states expressly. This is consistent with Board policy, under which settlements and their approval by the Board are considered to be specific to the facts of the particular case, and not precedents unless clearly so stated.

It is also agreed that this Settlement Proposal is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Settlement Proposal. However, none of the Parties will in any subsequent proceeding take the position that the resolution therein of any issue settled in this Settlement Proposal, if contrary to the terms of this Settlement Proposal, should be applicable for all or any part of the 2015 Test Year.

The Parties agree that the following unsettled issues will be addressed by way of a hearing for determination by the Board:

- Is the applicant's proposal to recover the RRRP funding variance from the 2002 to 2007 period appropriate?
- Are the proposed revenue-to-cost ratios appropriate?
- Are the proposed fixed/variable splits appropriate?

The Parties believe that an oral hearing is the most appropriate forum to address these unsettled issues because the Board will be privy to discussions made during witness examination, and an oral hearing will give the Board the opportunity to ask API's witnesses and the intervenors questions should any arise.

The Settlement Proposal provides a description of each of the settled issues, together with references to the evidence before the Board. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the responses to Interrogatories and Technical Conference Questions and Undertakings, and all other components of the record up to and including the date hereof, including additional information included by the Parties in this Settlement Proposal, and the Attachments to this document.

References to the evidence supporting this Settlement Proposal on each issue are set out in each section of this Settlement Proposal. The Attachments were prepared by the Applicant. The Intervenors are relying on the accuracy and completeness of the Attachments in entering into this Settlement Proposal.

The revenue requirement and rate adjustments arising from this Settlement Proposal will allow Algoma Power to make the necessary investments to serve customers, maintain the integrity of the distribution system, to maintain and improve the quality of its service, and to meet all compliance requirements during 2015.

Algoma Power has filed budgets for the Test Year that are illustrative of how it would achieve these goals, however, the actual decisions as to how to allocate resources and in what areas to spend the agreed- upon capital and OM&A are ones that must be made by the utility during the course of the year. This is typical of all forward test year cost of service applications, and such decisions are subject to the Board's normal review in subsequent proceedings. Furthermore, Algoma Power submits that the reduced amounts of capital and OM&A that were agreed on through settlement, may not allow Algoma Power to sufficiently complete all projects/plans as they were originally contemplated in the Application.As noted above this will not compromise its ability to maintain the integrity of its distribution system and its service quality.

ORGANIZATION AND SUMMARY OF THE SETTLEMENT PROPOSAL

The following Attachments accompany this Proposal:

"A" – The Issues List Decision dated August 28, 2014
"B" – Updated Chapter 2 Appendices (*from the Filing Requirements for Electricity Distribution Rate Applications*)

The following list identifies those Appendices that have been updated since the original Amended Application datedMay 27, 2014 filing:

2-BA: Fixed Assets Continuity Schedule, December 31, 2014

2-BA: Fixed Assets Continuity Schedule, December 31, 2015

2-H: Other Operating Revenue Offset Table

2-P: Cost Allocation

2-V: Revenue Reconciliation

2-W: Bill Impacts

2-Z: Tariff of Rates and Charges

“C” – Schedule of Cost of Power

“D” – Tax Calculations

“E” – Adjustment to 2015 Load Forecast with CDM Adjustment

“F” – Revenue Requirement Workform

"G" - API/Algoma Coalition Stakeholder Sessions

The following electronic models will accompany this Settlement Proposal and will be filed with the Board:

A. Revenue Requirement Workform; API 2015_RRWF_Settlement 20141010.xlsm
B. Rate Design Model; API_Settlement_2015EDR_RateDesign_20141010.xlsx
C. Bill Impact Model;API_2015EDR_Bill_Impact _Model_Settlement_20141010.xlsx
D. Cost Allocation Model;API_ 2015_Cost_Allocation_Model_V3 1 - Settlement_20141010.xlsm
E. Settlement Appendices: Settlement_Appendices_20141010.xlsx

This Settlement Proposal has been organized to follow the Board's approved Issues List. It should be noted that the Issues List was not available to Algoma Power at the time it prepared its pre-filed evidence, nor was it available to the Intervenors at the time they prepared their interrogatories and technical conference questions. As such, although the Parties have organized this Settlement Proposal in accordance with the Issues List, we trust that the Board will appreciate the difficulty of addressing each sub-issue individually, given that none of the evidence in this proceeding was organized in this manner.

OVERVIEW OF THE SETTLEMENT PROPOSAL

The Parties have reached a partial settlement.

In reaching settlement, the Parties have been guided by the Filing Requirements for 2014, and the *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 (“RRFE”).

The agreement among the Parties reduces Algoma Power’s applied-for service revenue requirement by $558,675, from $23,863,189 to $23,304,514.

Table 1 below provides the components of Algoma Power’s revenue requirement for the 2015 Test Year, incorporating the changes as settled.

Table 1. Contributions to Change to Revenue Requirement

		Applied-for		Settlement		Change	
		%	$	%	$	%	$
1	Rate Base		99,266,498		98,071,831		- 1,194,666
2	Cost of Capital	6.71%		6.71%		-	
3	Return on Rate Base		6,663,164		6,582,973		- 80,192
4	OM&A Expenses		12,812,679		12,412,679		- 400,000
5	Amortization		3,947,009		3,899,209		- 47,800
6	Income Taxes (including other tax credits)		440,336		409,653		- 30,683
7	2015 Service Revenue Requirement		23,863,189		23,304,514		- 558,675
8	Less Miscellaneous Revenue		436,758		466,758		30,000
9	2015 Base Revenue Requirement		23,426,431		22,837,756		- 588,675

Table 2 details the individual contributions of matters arising from the interrogatory process and the settlement to the change in Rate Base.

Table 2 Proposed Settlement Rate Base

RATE BASE

Description	2014 Bridge Year	Stranded Meters	2014 Bridge Year Revised	2015 Test Year	Other Settlement Adjustments	Revised 2015 Test Year
Gross Fixed Assets	157,557,032	(890,528)	156,666,504	165,812,251		165,812,251
Accumulated Depreciation	(65,418,323)	652,221	(64,766,102)	(68,713,111)	47,800	(68,665,311)
Net Book Value	92,138,709	(238,307)	91,900,402	97,099,140		97,146,940
Average Net book Value				94,499,771		94,523,671
Working Capital Requirement				35,750,569		
Proposed Adjustment to OM&A					(400,000)	
Increase in Cost of Power					131,033	
Net change in Working Capital Requirement					(268,967)	35,481,602
Working Capital Allowance				4,647,574	10%	3,548,160
Rate Base				99,147,345		98,071,831
Original Rate Base						99,266,498
Difference						(1,194,667)

The change to the rate base is attributable to several factors, these are:

- Interrogatory 2 – Energy Probe – 8 highlighted a matter associated with the stranded meters in gross assets and accumulated depreciation. In API's response to this interrogatory the rate base for 2015 was re-calculated on the average of opening and closing net book value for 2015 with the opening balance excluding stranded meters. The re-calculation of the 2015 rate base provided with API's interrogatory response is reflected in Table 1.
- For the purpose of settlement, API has reduced its proposed amortization expense in the test year by $47,800.
- API has reduced its proposed working capital requirement by $400,000 reflecting the reduction, for the purpose of settlement, in its 2015 test year proposed OM&A expense.
- API has increased its cost of power by $131,033 to reflect the changes to the load forecast as accepted by the Parties. Details of the determination of the changes to the cost of power were presented in Undertaking JT1.8.
- For the purpose of settlement, API has reduced its working capital allowance from 13% to 10% of the revised working capital requirement.

The accumulated effect of each of these measures reduces API's proposed test year rate base by $1,194,667 from $99,266,498 to $98,071,831.

This reduction of $1,194,667 in the test year rate base has the further effect of reducing API's return on rate base by $80,192 and reducing income tax, both as detailed in Table 1.

The remaining contributors to the reduced 2015 test year revenue requirement are the $400,000 reduction to OM&A expense, the $47,800 decrease in amortization expense, the resultant changes to income tax, including the $7,425 apprenticeship tax credit, and the $30,000 increase in the 2015 test year forecast for other revenue. These accumulated reductions to rate base are partially offset by a $131,033 increase in cost of power. This increase in cost of power is solely attributable to the revised load forecast which adds 1,133,546 kWh of energy throughput. Each of these matters is addressed individually in this Proposed Settlement Agreement.

Table 3below provides bill impacts for a typical customer by rate class for the Proposed Settlement Base Revenue Requirement. These rate impacts have been calculated on the basis of a rate design incorporating the actual 2015 RRRP Adjustment Factor of 0.79% which as issued by the Board on October 3, 2014.

Table 3 Summary of Total Bill Impacts

Summary of Bill Impacts				Total Bill		
Customer Class	Type	Usage kWh	Demand kW	Includes OCEB (if applicable)		
				Current	Proposed	%
Residential - R1	RPP-TOU	250		63.04	61.55	-2.38%
		800		147.58	138.19	-6.36%
		1,500		255.18	235.76	-7.61%
		2,000		332.03	305.43	-8.01%
		5,000		793.16	723.52	-8.78%
		10,000		1,561.71	1,420.33	-9.05%
		15,000		2,330.26	2,117.16	-9.15%
Residential - R2	Non-RPP	30,000	50	4,694.57	4,858.65	3.49%
		81,000	160	11,753.29	12,269.77	4.39%
		90,000	225	13,406.62	14,119.30	5.32%
		4,100,000	6,000	542,714.15	562,688.13	3.68%
R2, Interval	Non-RPP	90,000	225	13,502.27	14,119.30	4.57%
Seasonal	RPP-TOU	287		110.14	109.78	-0.33%
		1,000		292.68	297.47	1.63%
Street Lighting	Non-RPP	150	1	50.17	54.75	9.12%
		19,056	62	6,364.05	6,937.78	9.02%

The billing parameters for a Street Lighting customer i.e., 19,056 kWh and 62 kW are changed from the evidence presented in the original Application. This change is intended make the example illustrative of an actual API Street Lighting customer as was discussed during the review stage of the Application.

Table 4 below provides a more detailed bill impact assessment.

Table 4 Detailed Summary of Bill Impacts

Summary of Bill Impacts

Customer Class	Type	Usage kWh	Demand kW	Sub-Total A			Sub-Total B			Sub-Total C			Total Bill		
				Excludes Pass Through			Distribution			Delivery			Includes OCEB (if applicable)		
				Current	Proposed	%	Current	Proposed	%	Current	Proposed	%	Current	Proposed	%
Residential - R1	RPP-TOU	250		31.46	33.00	4.88%	34.17	32.60	-4.60%	37.46	35.98	-3.94%	63.04	61.55	-2.38%
		800		49.72	50.10	0.76%	56.66	47.09	-16.88%	67.17	57.92	-13.77%	147.58	138.19	-6.36%
		1,500		72.96	71.87	-1.49%	85.27	65.54	-23.14%	104.99	85.85	-18.24%	255.18	235.76	-7.61%
		2,000		89.56	87.42	-2.39%	105.72	78.72	-25.54%	132.01	105.79	-19.86%	332.03	305.43	-8.01%
		5,000		189.16	180.72	-4.46%	228.36	157.78	-30.91%	294.09	225.47	-23.33%	793.16	723.52	-8.78%
		10,000		355.16	336.22	-5.33%	432.78	289.55	-33.09%	564.23	424.92	-24.69%	1,561.71	1,420.33	-9.05%
		15,000		521.16	491.72	-5.65%	637.19	421.32	-33.88%	834.37	624.38	-25.17%	2,330.26	2,117.16	-9.15%
Residential - R2	Non-RPP	30,000	50	753.62	713.25	-5.36%	985.58	1,109.82	12.61%	1,223.77	1,368.06	11.79%	4,694.57	4,858.65	3.49%
		81,000	160	1,100.12	970.92	-11.74%	1,726.41	2,116.87	22.62%	2,488.61	2,943.23	18.27%	11,753.29	12,269.77	4.39%
		90,000	225	1,304.87	1,123.18	-13.92%	2,000.74	2,538.50	26.88%	3,072.59	3,700.56	20.44%	13,406.62	14,119.30	5.32%
		4,100,000	6,000	19,496.12	14,651.12	-24.85%	51,197.06	66,343.48	29.58%	79,779.59	97,331.82	22.00%	542,714.15	562,688.13	3.68%
R2, Interval	Non-RPP	90,000	225	1,304.87	1,123.18	-13.92%	2,000.74	2,538.50	26.88%	3,157.24	3,700.56	17.21%	13,502.27	14,119.30	4.57%
Seasonal	RPP-TOU	287		73.41	76.50	4.21%	76.41	75.93	-0.62%	80.18	79.82	-0.45%	110.14	109.78	-0.33%
		1,000		168.81	185.52	9.90%	177.28	181.56	2.41%	190.43	195.10	2.45%	292.68	297.47	1.63%
Street Lighting	Non-RPP	150	1	24.71	27.50	11.29%	25.87	29.81	15.23%	29.50	33.54	13.71%	50.17	54.75	9.12%
		19,056	62	3,397.84	3,752.28	10.43%	3,545.18	4,045.86	14.12%	3,770.21	4,277.37	13.45%	6,364.05	6,937.78	9.02%

In its Application, API had requested RRRP funding of $14,515,412. In this Proposed Settlement Agreement, API is requesting RRRP funding of $13,964,040 a reduction of $551,372. This reduction has two primary drivers; the predominant driver is the reduction in Service Revenue Requirement of $558,675, and the second is API'sremoval of its request to recover $192,509 of stranded meter costs by allocating them to the Residential - R1 class. API will now recover these costs by way of a rate rider specific to the Residential – R1 rate class.These reductions are offset by the actual RRRP Adjustment Factor of 0.79% being significantly less than the assumed RRRP Adjustment factor in the Application of 3.76%. The RRRP Adjustment Factor directly impacts the share of revenue attributable to the Residential – R1 and Residential – R2 rate classes that is either recovered from rate or is allocated to RRRP funding.

In addition, the Parties agree that in the event that that Board is unable to implement Algoma Power's distribution rates by January 1, 2015, the Intervenors support a January 1, 2015 effective date for distribution rates.

PLANNING

a) Capital

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

i. customer feedback and preferences;
ii. productivity;
iii. benchmarking of costs;
iv. reliability and service quality;
v. impact on distribution rates;
vi. trade-offs with OM&A spending;
vii. government-mandated obligations; and
viii. the applicant's objectives.

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 2; Interrogatory 2-Energy Probe-8, Interrogatory 2-Staff-8

For the purposes of settlement, the Parties accept that the level of planned capital expenditures is appropriate, as is the rationale for planning and pacing choices, and has been adequately explained giving due consideration to the items listed in i-viii above, subject to the qualifications set out below.

Qualifications:

i) Stranded Meters: For the purpose of settlement, the Parties agree that Algoma Power's opening 2015 rate base should be reduced by $119,153, being one half of the net book value of stranded meters removed from opening rate base, as shown in Table 6 provided in the summary to this section.The evidentiary basis for this change is API's response to interrogatory 2-Energy Probe-8.

ii) Allowance for Working Capital: For the purpose of settlement, the Parties agree that Algoma Power's allowance for working capital will be calculated based on 10% of the sum of cost of power and controllable expenses, instead of 13% as originally proposed by Algoma Power. The effect of decreasing the allowance for working capital has been partially offset by an increase in the cost of power of $131,033. The increase in cost of power is a consequence of the change to the load forecast which is being used in this Proposed Settlement Agreement. The Parties have agreed to use the load forecast defined by Undertaking JT1.8. The impact of the change in load forecast on the elements contributing to the cost of power is shown below in Table 5.

Table 5 The2015 Cost of Power Expense Summary

2015 Cost of Power Expense Summary						
Charge Type	Updated as per Undertakings		As per the Application		Change	
4705 - Cost of Power	$ 19,243,046		$ 19,132,846		$ 110,200	
4708 - Charges - WMS	$ 949,245		$ 943,800		$ 5,445	
4714 - Charges - NW	$ 1,449,453		$ 1,441,452		$ 8,001	
4716 - Charges - CN	$ 1,036,440		$ 1,030,661		$ 5,778	
4730 - Charges - Rural Rate Assistance	$ 280,459		$ 278,850		$ 1,609	
4751 - Charges - IESO SME	$ 110,281		$ 110,281		$ -	
Total	$ 23,068,922		$ 22,937,890		$ 131,033	

This table has been excerpted from API's response to Undertaking JT1.8 filed with the Board on August 22, 2014.

iii) Customer Feedback and Preferences: API will conduct an annual stakeholder session with the Algoma Coalition as described at Attachment "G".

Summary:

As a result of the qualifications set out above, the Parties accept that Algoma Power's 2015 rate base for the purpose of setting 2015 rates is $98,071,831. The Parties accept the following components of Algoma Power's 2015 rate base:

Table 6 Summary of Changes to the 2015 Rate Base

RATE BASE

Description	2015 Test Year Application	2014 Bridge Year	Stranded Meters	2014 Bridge Year Revised	2015 Test Year, IR Response	Other Settlement Adjustments	Proposed Settlement 2015 Test Year
Gross Fixed Assets	165,812,251	157,557,032	(890,528)	156,666,504	165,812,251		165,812,251
Accumulated Depreciation	(68,713,111)	(65,418,323)	652,221	(64,766,102)	(68,713,111)	47,800	(68,665,311)
Net Book Value	97,099,140	92,138,709	(238,307)	91,900,402	97,099,140		97,146,940
Average Net book Value	94,618,924				94,499,771		94,523,671
Working Capital Requirement	35,750,569				35,750,569		
Proposed Adjustment to OM&A						(400,000)	
Increase in Cost of Power						131,033	
Net change in Working Capital Requirement						(268,967)	35,481,602
Working Capital Allowance	4,647,574				4,647,574	10%	3,548,160
Rate Base	99,266,498				99,147,345		98,071,831

b) OM&A

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

i. customer feedback and preferences;
ii. productivity;
iii. benchmarking of costs;
iv. reliability and service quality;
v. impact on distribution rates;
vi. trade-offs with capital spending;
vii. government-mandated obligations; and
viii. the applicant's objectives

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 4; Interrogatory 4-Energy Probe-25, Interrogatory 4-Energy Probe-29, Interrogatory 4-Staff-21

For the purposes of settlement, the Parties accept that the level of planned OM&A expenditures as agreed to is appropriate, as is the rationale for planning choices, and has been adequately explained giving due consideration to the items listed in i-viii above, subject to the qualifications set out below. The parties have given consideration to the matters of productivity and benchmarking of costs and are conscious of the Board's Decision in the matter of API's 2014 incentive rate-setting application; EB-2013-0110. In its Decision, the Board found that the PEG model, although applicable to the vast majority of distributors, may not apply to distributors that are particularly unique.[1] Further in its Decision, the Board indicated that it was providing

[1] Decision and Order, EB-2013-0110 dated February 20, 2014, page 7 & 8

Algoma with sufficient time to decide on the appropriate course of action for future incentive rate setting.[2] API is scheduled to apply for a form of incentive rate-setting in 2015 for rates effective January 1, 2016. In that application API will address productivity and benchmarking of costs.

Qualifications:

i) OM&A:

For the purpose of settlement, the Parties agree that Algoma Power will reduce its proposed 2015 OM&A expense of $12,704,879 by $400,000, resulting in a 2015 OM&A budget of $12,304,879.The Parties agreed on the adjustment based on an “envelope” approach, so that any determination of potential budget reductions to reflect the Board-approved 2015 OM&A will be at the discretion of Algoma Power.

ii) Amortization:

For the purpose of settlement, the Parties agree that Algoma Power will adjust its operating costs for the purpose of setting 2015 rates by reducing its proposed amortization expense in the Test Year by $47,800,representing the difference between the actual amortization expense for capital additions from 2011 through 2013 which was determined based on depreciation being calculated in the month following when an asset was placed in service and the amount that would have been calculated ifthe half-year-rule had been used.The evidentiary basis for the quantum of this reduction is Algoma Power's response to interrogatory 4-Energy Probe-25.

iii) Apprenticeship Tax Credit:

For the purpose of settlement, the Parties agree that Algoma Power will reduce its forecast 2015 income tax expense by $7,425 representing an Ontario apprenticeship training tax credit in the Test Year. The evidentiary basis for the quantum of this reduction is Algoma Power's response to interrogatory 4-Energy Probe-29.This tax credit is included in the determination of the test year income tax amount shown on line 6 of Table 1.

[2] Decision and Order, EB-2013-0110 dated February 20, 2014, page 8

iv) Customer Feedback and Preferences: API will conduct an annual stakeholder session with the Algoma Coalition as described at Attachment "G".

Summary:

As a result of the qualifications set out above, the Parties accept that Algoma Power's 2015 operating costs for the purpose of setting 2015 rates is as shown below in Table 6.

Table 6. Contributions to Change to 2015 Operating Costs

	Applied-for $	Settlement $	Change $
OM&A Expenses	12,812,679	12,412,679	- 400,000
Amortization	3,947,009	3,899,209	- 47,800
Income Taxes (including other tax credits)	440,336	409,653	- 30,683
Total	17,200,024	16,721,541	- 478,483

REVENUE REQUIREMENT

i. Have all elements of the Base Revenue Requirement been appropriately determined in accordance with Board policies and practices?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 6; Interrogatory 6-Staff-30

For the purposes of settlement, the Parties accept that all elements of the Base Revenue Requirement have been appropriately determined in accordance with Board policies and practicesthat the Parties are aware of including, but not limited to, the Board's Filing Requirements and the RRFE. More specifically, in negotiating this Settlement Proposal the Parties were mindful of achieving the objectives set out in the RRFE, those being: customer focus; operational effectiveness; public policy responsiveness; and financial performance.

Changes to individual components of the revenue requirement have been noted and explained under sections 1a and 1b above.

ii. Has the Base Revenue Requirement been accurately determined based on these elements?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 6; Interrogatory 6-Staff-31

For the purposes of settlement, the Parties accept that all elements of the Base Revenue Requirement has been accurately determined in accordance with Board policies and practices including, but not limited to, the Board's Filing Requirements and the RRFE. As set out above, the Parties agree to Algoma Power's 2015 base revenue requirement in the amount of $22,837,756.

Further, for the purpose of settlement the Parties agree that Algoma Power's 2015 forecast other revenues used to set 2015 rates should be increased by $30,000 from $436,758 to $466,758.

The following table that illustrates the components of Algoma Power's base revenue requirement:

Table 7 Components of Revenue Requirement

	Applied-for		Settlement		Change	
	%	$	%	$	%	$
Rate Base		99,266,498		98,071,831		- 1,194,666
Cost of Capital	6.71%		6.71%		-	
Return on Rate Base		6,663,164		6,582,973		- 80,192
OM&A Expenses		12,812,679		12,412,679		- 400,000
Amortization		3,947,009		3,899,209		- 47,800
Income Taxes (including other tax credits)		440,336		409,653		- 30,683
2015 Service Revenue Requirement		23,863,189		23,304,514		- 558,675
Less Miscellaneous Revenue		436,758		466,758		30,000
2015 Base Revenue Requirement		23,426,431		22,837,756		- 588,675

LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

i. Are the proposed customer classes, load and customer forecast, loss factors, CDM adjustments and resulting billing determinants an appropriate reflection of the energy and demand requirements of the applicant and its customers?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 3; Interrogatory Algoma Coalition #6, Interrogatory 3-Staff-19, Interrogatory 3-Energy Probe-13, Interrogatory 3-Energy Probe-15, Interrogatory 3-VECC-11, Interrogatory 3-VECC-16, Undertaking No. JT1.6, Undertaking No.JT1.7, Undertaking No. JT1.8

For the purposes of settlement, the Parties accept thatAlgoma Power's customer classes, load and customer forecast, CDM adjustments and resulting billing determinants as presented in the Application are an appropriate reflection of the energy and demand requirements of the Applicant and its customers, subject to the following qualifications:

Qualifications:

i) Load Forecast:
For the purposes of settlement, the Parties accept the customer and load forecast as was presented by API in response to undertakings JT1.6, JT1.7 and JT1.8 arising from the Technical Conference, of this proceeding, held on August 20, 2014.

Table 8, below, provides a comparison of the load forecast accepted by the Parties for the Proposed Settlement and that used in the original Application.

Table 8 Revised Test Year Forecast

Algoma Power Inc. Test Year Load Forecast

	Per Undertakings	Per Application	Change
Retail kWh	2015 CDM Adjusted Load Forecast	2015 CDM Adjusted Load Forecast	
Residential - R1	105,791,701	104,826,589	965,112
Seasonal	7,731,414	7,680,066	51,348
Residential - R2	83,288,188	83,171,116	117,072
Street Lights	804,705	804,690	15
Total Customer (kWh)	197,616,007	196,482,461	1,133,546
kW	2015 CDM Adjusted Load Forecast	2015 CDM Adjusted Load Forecast	
Residential - R1	-		
Seasonal	-		
Residential - R2	198,901	198,897	4
Street Lights	2,380	2,380	0
Total Customer (kW)	201,281	201,277	4

Table 9 provides a clear definition of the test year forecast with respect of the adjustments made for CDM for each customer classification.

Table 9 Class Specific Adjustments to Load Forecast

Adjustment To Load Forecast

Algoma Power Inc.

Retail kWh	Weather Normalized 2015F (Elenchus)		CDM Load Forecast Adjustment	2015 CDM Adjusted Load Forecast
	A	C = A / B	E = D * C	F = A - E
R1 (kWh)	106,126,288	54%	334,587	105,791,701
Seasonal (kWh)	7,755,866	4%	24,452	7,731,414
R2 (kW)	83,551,603	42%	263,415	83,288,188
Street Lights (kW)	807,250	0%	2,545	804,705
Total Customer (kWh)	198,241,007	100%	625,000	197,616,007
	B		D	

kW	Weather Normalized 2015F (Elenchus)		CDM Load Forecast Adjustment *	2015 CDM Adjusted Load Forecast
	G	I = G / H	J = G / A * E	K = G - J
R1 (kWh)	-	0%		-
Seasonal (kWh)	-	0%		-
R2 (kW)	199,530	99%	629	198,901
Street Lights (kW)	2,388	1%	8	2,380
Total Customer (kW)	201,918	100%	637	201,281

Finally Table 10 is the detailed test year weather normalized customer and load forecast used for the rate design in the Proposed Settlement.

Table 10 Test Year Customer and Load Forecast

2015 Test Year Normalized Customer and Load Forecast Information

Customer Class Name	2010 Actual	2011 Actual	2012 Actual	2013 Year End	2013 Normalized	Bridge Year 2014 Normalized	Test Year 2015 Normalized
Customers and Connections							
Residential - R1	8,031	8,082	8,166	8,306	8,306	8,432	8,559
Seasonal	3,538	3,453	3,405	3,298	3,298	3,191	3,084
Residential - R2	43	46	49	50	50	50	50
Street Lighting (# of Connections)	1,052	1,052	1,018	1,018	1,018	1,018	1,018
TOTAL	12,664	12,633	12,638	12,672	12,672	12,691	12,711
Volumes in kWh							
	2010 Actual	2011 Actual	2012 Actual	2013 Year End	2013 Normalized	Bridge Year 2014 Normalized	Test Year 2015 Normalized
Residential - R1	98,515,494	103,344,412	103,512,450	106,250,425	104,788,841	104,839,037	105,791,701
Seasonal	11,130,245	10,087,145	10,136,343	8,458,860	8,342,500	8,025,496	7,731,414
Residential - R2	70,938,155	75,394,032	79,423,076	83,700,857	83,416,121	83,425,900	83,288,188
Street Lighting	721,376	523,958	728,404	807,250	807,250	807,250	804,705
TOTAL	181,305,270	189,349,547	193,800,273	199,217,392	197,354,712	197,097,683	197,616,008
Volumes in kW							
	2010 Actual	2011 Actual	2012 Actual	2013 Year End	2013 Normalized	Bridge Year 2014 Normalized	Test Year 2015 Normalized
Residential - R1							
Seasonal							
Residential - R2	163,570	176,514	185,948	199,530	199,530	199,530	198,901
Street Lighting	Note: Street Ligting revenue in API is based on kWh.						
TOTAL	163,570	176,514	185,948	199,530	199,530	199,530	198,901
	N/a	**2011 Actual**	**2012 Actual**	**2013 Actual**		**2014 Actual**	**2015 Board Calculation**
RRRP Adjustment Factor		2.500%	2.810%	3.750%		3.760%	0.790%
Transformer Ownership Allowance							
kW		115,523	118,393	123,494		123,494	123,494
$		69,314	71,036	74,096		74,096	74,096

Is the proposed cost allocation methodology including the revenue-to-cost ratios appropriate?

Status: No Settlement

Supporting Parties: N/A

Evidence: Exhibit 7; Interrogatory 7Staff32, Interrogatory 7Staff33, Interrogatory 7Staff34, Interrogatory 7-VECC-31, Interrogatory 7-VECC-33, Interrogatory 7-VECC-34, Interrogatory 7-VECC-35, Undertaking No. JT1.8

The Parties request that this issue be addressed by an oral hearing for the reasons set out above.

Are the Applicant's proposals for rate design appropriate?

Status: No Settlement

Supporting Parties: N/A

Evidence: Exhibit 8; Interrogatory 8-Energy Probe-35, Interrogatory 8-VECC-36, Interrogatory 8-VECC-37, Interrogatory 8-VECC-41

The Parties request that this issue be addressed by an oral hearing for the reasons set out above.

Is the Applicant's proposal for RRRP funding appropriate?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 8, Interrogatory 7-VECC-34, Interrogatory Algoma Coalition #4, Interrogatory Algoma Coalition #5, Interrogatory 8-Energy Probe-35, Interrogatory 8-VECC-36, Undertaking No. JT1.8

For the purposes of settlement, the Parties accept that Algoma Power's proposal for RRRP funding methodology is appropriate.API's electricity distribution rates for Residential Service Classification (both Residential R–1 and Residential R–2) are adjusted in accordance with Ont. Reg. 442/01. The electricity distribution rates for these classes are adjusted in line with the average of rate adjustments of select rate classes of other distributors in the most recent rate year, as calculated by the Board; the RRRP Adjustment Factor. The approved method of calculating the average rate adjustments of other distributors in order to calculate the rate increase for the customers of API, and the remaining amount that is payable under RRRP, was decided in the Board's Decision and Order, EB-2009-0278, dated November 11, 2010.

Shown below is the RRRP funding determination which has been excerpted from the API Proposed Settlement Rate Design Model accompanying this Proposed Settlement. The RRRP funding being requested in this Proposed Settlement Agreement is $13,964,040. This amount has been calculated using the Board's issued calculation of the 2015 RRRP Adjustment Factor of 0.79%.

Table 11 Calculation of the 2015 RRRP Funding Amount

Determination of Residential R1 & R2 2015 Electricity Distribution Rates and RRRP Funding

2015 Distribution Base Rate Determination											
			Billing Determinant		**F/V Split**		**Distribution Rates**		**Revenues**		
Customer Class	**Metric**	**Average # of Customers**	**kWh**	**kW**	**Fixed Allocation**	**Variable Allocation**	**Monthly Service Charge**	**Variable Charge**	**Fixed**	**Variable**	**Total Revenue**
Residential - R1	kWh	8496	105,791,701		13.6%	86.4%	22.24	0.1356	2,267,699	14,349,470	16,617,169
Residential - R2	kW	50		198,901	12.0%	88.0%	820.21	18.1276	492,124	3,605,601	4,097,725
									2,759,823	**17,955,071**	**20,714,894**
2015 Application of Rate Indexing Methodology											
Delivery Charges Indexed by Simple Average of Other LDC Increases in Current Year											
Simple Average Increase in Delivery Charge for 2015 using the 2014 Board Approved RRRP Adjustment Factor											**0.79%**
			Billing Determinant		**F/V Split**		**Distribution Rates**		**Revenues**		
Customer Class	**Metric**	**Average # of Customers**	**kWh**	**kW**	**Fixed Allocation**	**Variable Allocation**	**Monthly Service Charge**	**Variable Charge**	**Fixed**	**Variable**	**Total Revenue**
Residential - R1	kWh	8496	105,791,701		40.7%	59.3%	23.34	0.0328	2,379,862	3,465,392	5,845,254
Residential - R2	kW	50		198,901	36.8%	63.2%	600.83	3.1131	360,498	619,199	979,696
Hold Residential - R2 Fixed Charge at $596.12					36.5%	63.5%	596.12	3.1273	357,672	622,024	979,696
Transformer Ownership Allowance - Allocated to the Residential - R2 class										74,096	74,096
									2,737,534	**4,087,417**	**6,824,951**
The Rural and Remote Rate Protection Amount Required for 2015											**$13,964,040**

ii. Do the impacts of any rate change require mitigation?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 8, Tab 2, Schedule 12

Table 12 below has been determined on the basis of the rate design accompanying this Proposed Settlement Agreement. There are no total impacts which exceed 10 percent and therefore API is not proposing rate mitigation.

Table 12 Summary of Bill Impacts

Summary of Bill Impacts						
Customer Class	**Type**	**Usage kWh**	**Demand kW**	**Total Bill**		
				Includes OCEB (if applicable)		
				Current	Proposed	%
Residential - R1	**RPP-TOU**	**250**		63.04	61.55	-2.38%
		800		147.58	138.19	-6.36%
		1,500		255.18	235.76	-7.61%
		2,000		332.03	305.43	-8.01%
		5,000		793.16	723.52	-8.78%
		10,000		1,561.71	1,420.33	-9.05%
		15,000		2,330.26	2,117.16	-9.15%
Residential - R2	**Non-RPP**	**30,000**	**50**	4,694.57	4,858.65	3.49%
		81,000	**160**	11,753.29	12,269.77	4.39%
		90,000	**225**	13,406.62	14,119.30	5.32%
		4,100,000	**6,000**	542,714.15	562,688.13	3.68%
R2, Interval	**Non-RPP**	**90,000**	**225**	13,502.27	14,119.30	4.57%
Seasonal	**RPP-TOU**	**287**		110.14	109.78	-0.33%
		1,000		292.68	297.47	1.63%
Street Lighting	**Non-RPP**	**150**	**1**	50.17	54.75	9.12%
		19,056	**62**	6,364.05	6,937.78	9.02%

ACCOUNTING

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

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 1, Tab 1, Schedule 11

For the purpose of settlement, the Parties accept that all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and the rate-making treatment of each of these impacts is appropriate.

API uses the ASPE accounting standard and has done so since January 1, 2011. Previous to January 1, 2011, API used the CGAAP accounting standard. Pursuant to the Board letter of July 17, 2012, API has applied changes to the depreciation expense and capitalization policies effective January 1, 2013, consistent with the Board's regulatory accounting policy direction in that letter. These changes are reflected in API's 2013 Actuals, 2014 Bridge Year and 2015 Test Year results.

ii. Are the Applicant's proposals for deferral and variance accounts and their disposition appropriate?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 9, Undertaking No. JT1.4

For the purpose of settlement, the Parties accept Algoma Power's proposals for deferral and variance accounts and their disposition including the extension of the sunset date on the rate rider to dispose of the Seasonal Mitigation deferral account.

Algoma Power applied for the recovery of its Group 1 regulatory deferral and variance account ("DVA") balances as at December 31, 2013, with projected interest to December 31, 2014. The total of Group 1 accounts requested for disposition is a credit of $452,421. API also sought recovery of selected Group 2 and other DVA accounts including: a debit of $18,864 for OEB 1568, LRAM Variance Account; a debit of $760,467 for OEB 1574, Deferred Rate Impact Amounts; a credit of $1,850,564 for OEB 1576, Accounting Changes under CGAAP; and a credit of $446,778 for OEB 1592,PILs and Tax Variance for 2006 and Subsequent Years. These amounts, as well as their disposition timeframesare set out in the following table.

This Settlement Proposal will result in the following rate riders:

Residential Service Classification		
Rate Rider for Recovery of Stranded Meter Assets (2014) - effective until December 31, 2015	$	1.8800
Rate Rider for the Disposition of Deferral/Variance Accounts (2014) - effective until December 31, 2015	$/kWh	(0.0129)
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	$/kWh	0.0201
Rate Rider for the the Recovery of Lost Revenue Adjustment (LRAM) - effective until December 31, 2015	$/kWh	0.0002
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	$/kWh	(0.0019)
Residential - R2 Classification		
Rate Rider for the Disposition of Deferral/Variance Accounts (2014) - effective until December 31, 2015	$/kW	(5.4026)
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	$/kW	8.4104
Rate Rider for the the Recovery of Lost Revenue Adjustment (LRAM) - effective until December 31, 2015	$/kW	0.0029
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	$/kW	(0.7877)
Seasonal Customers Classification		
Rate Rider for Deferral/Variance Account Disposition - effective until June 30, 2019	$/kWh	0.0307
Rate Rider for Stranded Meter Assets (2014) - effective until December 31, 2015	$	2.30
Rate Rider for the Disposition of Deferral/Variance Accounts (2014) - effective until December 31, 2015	$/kWh	(0.0129)
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	$/kWh	0.0201
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	$/kWh	(0.0019)
Street Lighting Service Classification		
Rate Rider for Deferral/Variance Account Disposition - effective until June 30, 2019	$/kWh	(0.0129)
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	$/kWh	0.0201
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	$/kWh	(0.0019)

OTHER

i Is the Applicant's proposal to seek recovery of the RRRP funding variance from the 2002 to 2007 period appropriate?

Status: No Settlement

Supporting Parties: N/A

Evidence: Exhibit 9, Tab 8; Interrogatory 9Staff41, Interrogatory 9-VECC43

The Parties request that this issue be addressed by oral hearing for the reasons set out above.