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Ontario

BY E-MAIL

July 21, 2013

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Algoma Power Inc. ("API")
2015 Electricity Distribution Rates
Board Staff Interrogatories
Board File No. EB-2014-0155

In accordance with Procedural Order No. 2, please find attached Board Staff interrogatories in the above proceeding. Please forward the following to API and to all other registered parties to this proceeding.

In addition please advise API that responses to interrogatories are due by August 7, 2014.

Yours truly,

Original Signed By

Suresh Advani

Encl.

Algoma Power Inc. (“API”)
2015Electricity Distribution Rates
EB-2014-0155
Board Staff Interrogatories

1. 0Staff1 - Responses to Letters of Comment

Following publication of the Notice of Application, has API received any letters of comment in respect of this application?

a) If so, please confirm whether a reply was sent by API in response to such comments and if so, please file copies of such responses with the Board.

b) If not, please explain why a response was not sent and advise whether API intends to respond and file a copy of the response if and when such response is given.

2. 1Staff2 – Conditions of Service

- Ref: Exhibit 1/Tab 1/Sch. 18/p. 1

a) Please identify any rates and charges that are included in the Applicant’s Conditions of Service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered through these rates and charges.

b) Please provide a schedule outlining the revenues recovered from these rates and charges from 2010 to 2013 inclusive, and the revenue forecasted for the 2014 bridge and 2015 test years.

c) Please explain whether, in the Applicant’s view, these rates and charges should be included on the Applicant’s tariff sheet of approved rates and charges.

3. 1Staff3 - Updated Appendix 2-W, Bill Impacts

- Ref: Exhibit 1/Tab 1/Sch. 6/p. 1
- Ref: Appendix 2-W (Exhibit 8/Tab 2/Sch. 11/p. 1)

Upon completing all interrogatories from Board staff and intervenors:

a) Please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (i.e. Residential – R1 800 kWh; Residential – R1 2,000 kWh).

4. 1Staff4 – Evolution of Customer Engagement

- Ref: Exhibit 1/Tab 3/Sch. 1
- Ref: Filing Requirements for Electricity Distribution Rate Applications[1] (section 2.4.2, page 8)

Chapter 2 of the Filing Requirements states, "The RRFE Report contemplates **enhanced** engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations." (Emphasis added)

a) Please describe the differences between customer engagement conducted in preparation for the current application and previous customer engagement.

b) Please explain how customer engagement has been enhanced.

5. 1Staff5 – Reflecting Customer Needs in the Application

- Ref: Exhibit 1/Tab 3/Sch. 1

1 http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Filing_Reqs_Dx_Applications_ch_1.2.3.5_20130717.pdf

- Ref: Filing Requirements for Electricity Distribution Rate Applications[2] (section 2.4.2, page 8)

Chapter 2 of the Filing Requirements states, "Distributors should specifically discuss in the application how their customers were engaged in order to determine their needs. This **could** include references to any communications sent to customers about the application such as bill inserts, town hall meetings held, or other forms of outreach undertaken to engage customers and explain to them how the application serves their needs and expectations and the feedback heard from customers through these engagement activities." (Emphasis added)

a) What forms of outreach were employed to explain how the current application serves the needs and expectations of customers? If none were employed, please explain why.

6. 2Staff6 – Rate Base

- Ref: Exhibit 2/Tab 1/Sch. 2/p. 1

Board staff notes the following year-over-year percentage increase in rate base since API's last cost-of-service rate application in the year 2011.

Variance	2012 Actual	2013 Actual	2014 Bridge	2015 Test Year
%	8.6%	8.8%	7.0%	4.9%

a) Please explain the material reason(s) for the year-over-year percentage increase in rate base for the historical years 2012 and 2013, bridge year 2013 and test year 2014.

2 http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Filing_Reqs_Dx_Applications_ch_1.2.3.5_20130717.pdf

7. 2Staff7 – Capex – Historical Pattern and Distribution Rate Impacts

- Ref: Exhibit 2/Tab 3/Sch. 2/p. 2

Upon comparing actual vs. approved capital expenditures for 2010 and 2011, Board staff notes an under expenditure of 8% to 10%.

a) Please provide reasons for the under expenditure.

b) Did API take this under expenditure trend into account when planning its capital expenditure forecast for the 2015 test year and beyond?

c) In its annual capital planning, does API consider rate impacts on its next cost-of-service application?

d) What changes ensued from these considerations with respect to the 2015 cost-of-service application?

8. 2Staff8 – Stranded Meters

- Ref: Exhibit 2/Tab 2/Sch. 1/p. 3 – 4

Board staff notes that API is proposing to dispose of a stranded meter balance of $278,026.

Board staff also notes that in its letter[3] to the Board, dated March 12, 2013, API identified a stranded meter disposition amount of $331,640, and proposed to apply for disposition of its stranded meters in its next cost-of-service application.

a) Please reconcile the two smart meter disposition amounts.

3 http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/386389/view/Algoma_Ltr_Stand%20Meters_20130312.PDF

9. 2Staff9 - Monthly Billing Impacts on Working Capital

- Ref: Exhibit 2/Tab 1/Sch. 5/p. 1
- Ref: Exhibit 2/Tab 1/Sch. 6/p. 1

a) Please identify the billing frequency that the applicant is planning on using for the test period and beyond.

b) If the applicant is planning to implement monthly billing, please refer to parts c) through g) below. If not, please explain why not.

c) Please identify any impacts that the implementation of monthly billing has had on billing and collection expenses or any other OM&A category.

d) Please identify the percentage of customers on e-billing as of December 31, 2013.

e) Please describe the Applicant's efforts to promote e-billing to its customers.

f) Please describe other initiatives that the Applicant has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.

g) As part of the decision making process, has the applicant determined the impact of the change to monthly billing on its working capital? If so, how is the working capital impacted by this change? If not, why not?

10. 2Staff10 – Asset Condition Assessment ("ACA")

- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.2.1(d) Vintage of Information on Investment Drivers
- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.3.2(c) Age profile tables
- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix B/Distribution Asset Management Plan ("DAMP")

In the 1st reference, API indicates that asset condition information feeds into the asset condition assessment process, which ultimately drives project identification and prioritization. API notes that it intends to improve the accuracy of API's asset record databases. Respecting the asset record, API also notes that "a complete inventory of standard distribution (excluding sub-transmission express feeder) pole and line assets was conducted in the early 1980's using standard collection methods available at the time […] API will endeavour over the next three to five years to audit and revise asset records and to collect more spatially accurate data using GPS and GIS technology".

At section 6 of the DAMP, API describes its methodology for managing its distribution assets. API also provides an age distribution for poles and overhead transformers. Staff notes that the health of assets may include several parameters including age.

a) Please augment reference 3 by including findings and recommendations for each asset category.

b) With the vintage of information at hand, has API developed a health or risk distribution of its assets?

c) If so, please submit a full picture of the asset population health or risk distribution by asset category.

d) If applicable, please submit the methodology for the development of a composite health/risk index.

e) Please indicate whether API has or will conduct an independent third party assurance review of its asset condition assessment.

11. 2Staff11 – Level of Service Targets, Performance Indicators & Performance Measurement

- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.4.1(d) Table of Capital Expenditures by Category
- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.4.5.2 Material Investments/Protection, Automation, Reliability

- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.2.3 Performance for Continuous Improvement
- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.2.1(b) Expected Sources of Cost Savings

The 1st reference tabulates 13 material capital projects/programs. Several of these are described in the 2nd reference as being driven by reliability considerations. Staff understands that these projects will impact customer service and service reliability indicators.

To illustrate, in the 2nd reference, in evaluating benefits, API notes that for this particular project, “each future 8-hour customer outage avoided for station maintenance activities or forced outages scenarios, the SAIDI benefit would be in the range of 0.74 to 1.24, depending on the station.”

With respect to performance, API notes in the 3rd reference that it compiles and submits reliability statistics and ESQR reports to the Board, and that these reports are reviewed to determine if any failure to meet target performance levels, or any trending in performance requires corrective action, or adjustments to future capital or maintenance programs.

The 4th reference provides a qualitative measure of various forecast cost saving sources.

a) Please identify the projects outlined at reference 1 that will have an impact on API’s levels of service. Where feasible, please quantify the anticipated improvement, and please highlight, where applicable, the cost/improvement trade-off.

b) Please indicate which relevant maintenance activities planned during the DSP will impact levels of service. Please provide a cost figure, and quantify anticipated improvements.

c) In order to identify planned spending (described in section 5.4.5.2) by driver, please tabulate all areas of capital and OM&A growth starting with the driver/need (e.g. poor reliability, worker safety, etc…) for the investment. Please indicate the anticipated directional or absolute result and expected timing of result. Please use the suggested format below as guidance:

Driver	Expenditure	Activities	Results & Timing	Corresponding Projects/ Programs at Reference 1
e.g.Poor reliability	Capital Expenditure Operational Expenditure	Increase maintenance Perform system modifications and additions Install real-time monitoring assets	Improved reliability by month/year X Improvements in customer satisfaction	

d) Where enhanced efficiencies are forecast over the DSP horizon or beyond as a result of the activities undertaken by API, please provide an estimate of the savings for each efficiency.

e) Please describe APIs plans to report on the projects/programs presented in the 1st reference.

12. 2Staff12 – Capex Forecast and Pacing

- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix D (Appendix 2-AB)

Board staff notes that API's annual capital expenditure forecast for the period 2015 (test year) to 2019 is in the $7M to $8M range for every year except 2017 where the forecast is $13.4M.

a) Please confirm whether the spike in the capital expenditure forecast for the year 2017 is entirely attributable to the Echo River TS upgrade project.

b) Please explain the planning process undertaken to evaluate the ensuing rate consequences of this investment schedule, including alternatives evaluated that would pace investments in a way that would lead to smoother rate impacts.

13. 2Staff13 – Pacing Considerations and Rate Impact

- RRFE Report[4]
- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.4.5.2 Material Investments

In addressing the methods to support proposed investments, at page 36, the RRFE highlights that "filings must enable the Board to assess whether and how a distributor has sought to control costs in relation to its proposed investments through the appropriate optimization, prioritization and pacing of investment expenditures."

a) Please discuss pacing considerations and rate impact associated with the investments at reference 2.

b) Please specify conditions (e.g. budgetary constraints, load adjustments, etc…) under which the current DSP would be modified and which planned projects would be deferred and/or abandoned? Please define qualitatively and quantitatively the impact of such investment deferrals.

14. 2Staff14 – Benchmarking Considerations

- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.3.1(b) Asset Management Process Overview
- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix E/4. Benchmarking
- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.4.5.2 Material Investments

API indicates at various points of the DSP that it uses some internal benchmarking for budgeting purposes, noting in the 1st reference for example that non-discretionary activities and general plant items are generally budgeted based on a five-year rolling average of historical activity and costs, and

[4] http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf

sustainment programs such as the Pole Replacement programs are generally budgeted based on the target replacement rate, (which is itself based on number, type, age and condition of in-service assets) times an estimated replacement cost per unit, based on analysis of historical costs.

The Vegetation Management ("VM") study includes a discussion on benchmarking in that context and the reasons why the use of benchmarking for VM may be difficult to achieve.

In the 3rd reference, certain assets such as the IT Hardware, and Fleet have cyclical patterns.

a) Is benchmarking against comparable industry peers or with respect to best practices part of API's capital and OM&A expenditure planning? If so, please specify.

b) If benchmarking is not part of expenditure planning process please explain why.

c) Please discuss benchmarking as it relates to:

    i. Pole replacement programs;
    ii. IT expenditures; and
    iii. Fleet related expenditures.

d) Please provide additional information related to the Sensus contract(s), scope of work and cost relative to other vendors

15.2 Staff15 – Regional Planning Considerations

- Exhibit 2/ Tab 3/ Sch.1/ Appendix A/ 5.2.1 (f) Contingencies
- Exhibit 2/ Tab 3/ Sch.1/ Appendix A/ Appendix B/Regional Infrastructure Planning (RIP) Process Letter of January 17, 2014

The 1st reference indicates that API has not included any capital expenditure related to regional planning in this DSP.

a) Please confirm that the Echo River TS planned project in 2017 is not part of the RIP.

b) Please discuss the cost implications of implementing the solutions proposed in the January 17, 2014 letter to remedy the described reliability concerns. Where cost sharing is anticipated, please indicate so.

c) Please indicate the likelihood and timing of carrying out any project related to the three areas where reliability concerns have arisen.

d) Does API anticipate any cost as a result of potential upgrades on the 44 kV system supplying API's Limer –No.4 circuit delivery point? Are these the upgrades that might trigger one of the ICMs discussed in the evidence? If different, please indicate the timing and quantum of the anticipated cost of the upgrades.

e) Please provide any relevant update following the July 23, 2014 RIP kick-off meeting.

f) What public engagement activities are planned as part of the regional planning initiative?

16. 2Staff16 – Overview of Assets Managed

- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.3.2(d) Overview of Assets Managed
- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.4.1(d) Table of Expenditures by Category
- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix B/DAMP

In the 1st reference, API indicates that it may bring 2 separate ICMs in connection with the Goulais TS / Batchawana TS and Limer/No.4 Circuit 44 kV Supply. API also indicates that is in discussions with GLPT in respect of the Echo River TS and cost responsibility considerations. The 2nd reference shows that construction of the Echo River TS project is planned for 2017 and forecast to cost M$4.55.

In the 1st reference, the asset management process flowchart shows two asset planning outputs, namely capital plans and inspection and maintenance programs.

Section 4 of the DAMP discusses inspection and maintenance programs, but historical or forecast cost figures are not provided.

a) Please indicate what material projects/programs resulted from capacity/contingency analyses versus those that were driven by the ACA. Where applicable please submit evidence

b) As the largest standalone cost item of the DSP:
   i. Please explain why API expects any cost sharing in respect of Echo River TS. What percentage share would API be responsible for?
   ii. Please indicate whether the amount in the 2nd reference excludes any cost sharing.
   iii. If applicable, please update the Board on any developments between API and GLPT.

c) Please indicate the likelihood of bringing the two ICMs discussed at reference 1 and their respective cost implications.

d) Please distinguish multi-year capital projects from inspection and maintenance programs presented at reference 2.

e) To provide an expenditure picture that allows a comparative analysis, please include capital and O&M in the same schedule for all relevant system and non-system assets, historical and forecast.

f) Please provide trends over time for all major capital expenditures, capital vs. O&M (planned vs. unplanned) and capital vs. depreciation for the 10 year-period. Please also provide explanations of trends and outliers.

17. 2Staff17 – Justifying Plan Expenditures

- Ref: Exhibit 2/Tab 3/Sch. 1/Appendix A/5.4.5.2 Material Investments

To establish whether the most cost-effective actions have been adopted, whether pacing of the investments is appropriate, and establish the value and rate impacts of material projects/programs on ratepayers, the evidence at the reference should include additional quantitative information on the economics of the projects/programs.

a) For material projects/programs, please distinguish between discretionary and non-discretionary projects, and provide:

   i. An overview of the economics of the project (eg. assumptions, NPV calculation) and a discussion of alternatives in that context ;
   ii. Where applicable please reference or submit additional documentation, such as independent studies that support a recommended option;
   iii. The impact of the project on rates;
   iv. Any investment pacing considerations related to the project; and
   v. Quantitative benefits to be incurred from maintaining/upgrading or replacing the asset(s), such as lower operating costs, increased efficiency, etc.

b) For programs, please provide:

   i. An overview of the economics of the program and a discussion of alternatives and benchmarking (internal /external/best practices);
   ii. The impact of the program on rates;
   iii. Any investment pacing considerations related to the program and the expenditure cycle adopted; and
   iv. Benefits to be incurred from planned expenditures on program, such as lower operating costs, increased reliability, etc.

18. 3Staff18 – Other Revenue

- Ref: Exhibit 3/Tab 1/Sch. 1/p. 2/Table 3.1.1.1

Board staff notes that Algoma Power's total Other Revenues for 2013 actual and 2014 bridge year are negative, i.e. ($273,128) and ($296,090) respectively. Board staff further notes that the drivers for the negative total are negative revenue values for "Regulatory Debits" and "Cost and Expenses of Merchandising, Jobbing, etc."

a) Please explain what is included in "Regulatory Debits" and "Cost and Expenses of Merchandising, Jobbing, etc."

b) Please clarify why the revenue values for "Regulatory Debits" and "Cost and Expenses of Merchandising, Jobbing, etc." are negative?

c) Please explain why Merchandising and Jobbing initiatives are undertaken if they are unable to result in positive revenues for API?

19. 3Staff19 – Load Forecast

- Ref: Exhibit 3/Tab 1/Sch. 2/Appendix A – Elenchus Report/Sch. 2/p. 2
- Ref: Load Forecast Model Excel File/Tab "OLS Model"

Board staff notes the following multiple regression analysis coefficients and corresponding standard error.

	Coefficient	Standard Error
Constant	5,809,523.564	1,304,324.332
Monthly HDD	9,432.89862	276.851516
Monthly CDD	67,375.6972	11,571.85289
Peak Days	115,509.4711	60,138.96742
Time	510.6920021	2371.339827

Board staff further notes that with respect to Peak Days, the standard error is more than half of the coefficient's value, and with respect to Time, the standard error is more than four times the coefficient's value.

a) Please run the regression analysis without the Time variable;

b) Please run the regression analysis without the Time and Peak Days variables; and

c) Given the problems with the regression analysis identified in a) and b), please indicate whether it is sufficiently robust to be used in the determination of rates?

20. 4Staff20 – Inflation Increase

- Ref: Exhibit 4/Tab 1/Sch. 1

Board staff is unable to ascertain the percentage inflation increase that API has applied to calculate expected expenditures.

a) Please provide the percentage inflation increase.

b) Please identify the source document for the inflation assumption.

21. 4Staff21 – OM&A Cost Increase

- Ref: Exhibit 4/Tab 1/Sch. 1/p. 1
- Ref: Board's Letter - Board Determination of Stretch Factor Rankings for 2013 3rd Generation Incentive Regulation Applications (IRM3)[5]
- Ref: Report of the Board - Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (EB-2010-0379)[6]

Board staff notes that API's proposed future OM&A increases are significant. The proposed OM&A costs for the test year 2015 represent a 16.6% increase compared to 2013 actuals, and a 34.5% increase compared to 2011 actuals.

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5 http://www.ontarioenergyboard.ca/oeb/_Documents/2013EDR/Board_ltr_LDC_2013_IRM3_Stretch_Factor_20121128.pdf

6 http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0379/EB-2010-0379_Report_of_the_Board_20131121.pdf (Appendix D)

a) Please identify any customer engagement that supports the increases proposed in this application.

b) Further, how has the Applicant communicated these benefits to its customers, and how did customers respond? Please provide some examples, including any customer feedback. If no communications took place, please explain why not

c) Please provide the analysis that was performed to assess API's planning decisions reflect best practices of Ontario distributors.

d) Please identify any initiatives considered and/or undertaken by API, including any analysis conducted, to optimize plans and activities from a cost perspective, for example, balancing cost levels of OM&A versus capital.

e) The Board's letter of November 28, 2012, established the stretch factor assignments for 2013 rates. API was assigned to Stretch Factor Group 3 out of three groups. On November 21, 2013, the Board established the stretch factor assignments for 2014 rates in the *Report of the Board: Rate Setting Parameters and Benchmarking under the renewed Regulatory Framework for Ontario's Electricity Distributors.* API was assigned to Group V out of five groups. Please provide details on any initiatives undertaken to improve API's assignment in future years.

f) Please identify what improvements in services and outcomes the applicant's customers will experience in 2015 and during the subsequent IRM term as a result of increasing the provision for OM&A in 2015 at the rate indicated.

22.4 Staff22 – OM&A (Administrative and General)

- Ref: Exhibit 4/Tab 1/Sch. 1/p. 1/Table 4.1.1.1

Board staff notes that API's actual costs for Administrative and General increased by 44% over the one year period 2012 to 2013, and have grown from this level since.

a) Please provide a detailed explanation for this increase, which appears to have been a permanent step-change in costs.

23. 4Staff23 – OM&A Cost Drivers

- Ref: Exhibit 4/Tab 2/Sch. 2/p. 1

Board staff notes the following notable increases in OM&A costs forecast by API for the test year 2015 from the bridge year 2014.

Outage Response Costs	$180,000
General Administration	$150,000
Vegetation Management	$840,000
SCADA	$176,000

a) Please explain the reason for the forecast increase in costs. What business decision led to the increases, and what alternatives were considered? What consideration was given to the additional value for customers as a result of these decisions? What customer input was sought to inform these decisions?

b) Further, please explain the projected change in API's operating environment to rationalize the forecast increase in costs; and

c) Are these projected cost increases for the test year 2015 expected to be a one-time event or recurring going forward?

24. 4Staff24 – OM&A Cost Per Customer and Full Time Equivalent ("FTE")

- Ref: Exhibit 4/Tab 2/Sch. 3/p. 1/Appendix 2-L

- Ref: Report of the Board - Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (EB-2010-0379)[7]
- Ref: OEB - 2012 Yearbook[8] of Electricity Distributors

Board staff notes API's OM&A costs per customer and FTE have steadily increased since 2012 to the test year 2015, and comparing the bridge year 2014 to the test year 2015 have increased by about 12%. Board staff also notes the other members of the stretch factor assignment group to which API has been assigned include: Hydro One Networks Inc., Toronto Hydro-Electric System Limited and Woodstock Hydro Services Inc.

a) What increased value, both qualitative and quantitative will the customers receive for the increased OM&A costs per customer and FTE.

b) Did API consider alternatives to keep the OM&A costs down, and if so, what?

c) A review of the OEB's most recent 2012 Yearbook of Electricity Distributors shows API's OM&A per customer much higher than the other distributors in Group 5. This result does not appear to be the same for OM&A per FTE. Please explain the operating conditions that lead to such differences and what plans API has to address this.

25. 4Staff25 – Amortization of Regulatory Costs

- Ref: Exhibit 4/Tab 8/Sch. 1/p. 1/Table 4.8.1.1
- Ref: Appendix 2-M

Board staff notes that API's costs related to its 2015 cost-of-service rate application comprise Legal costs of $110,000, Consultant costs of $40,000 and

[7] http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0379/EB-2010-0379_Report_of_the_Board_20131121.pdf (Appendix D)

[8] http://www.ontarioenergyboard.ca/oeb/_Documents/RRR/2012_Electricity_Yearbook.pdf

Intervenor cots of $75,000, each to be amortized over a cycle of five years. Board staff also notes that in Table 4.8.1.1 and Appendix 2-M, Legal costs and Consultant costs have been labeled as “One-Time”, whereas Intervenor costs have been labeled as “On-Going”.

a) Please confirm whether the “On-Going” label with respect to Intervenor costs is an oversight.

b) If the label is not an oversight please explain the rationale for Intervenor costs being deemed as “On-Going”.

26. 4Staff26 – Achievement of Objectives

- Ref: Exhibit 4/Tab 4/Sch. 1/Appendix A (Appendix 2-K)

With respect to non-management employees (union and non-union), the Applicant has proposed material (5.6%) increases in headcount and (8.1%) increases in employee compensation for the Test year relative to the 2013 actual levels.

a) What objectives has the applicant established for its operations?

b) Please provide specific information on why the proposed cost increases are necessary for the applicant to achieve the objectives that the applicant has targeted in the capital and operating expenditure sections of its application, and the alternative methods for achieving these objectives that were considered and rejected in favour of the proposed headcount and compensation increases.

27. 4Staff27 – Low-Income Energy Assistance Program (“LEAP”)

- Ref: Exhibit 4/Tab 9/Sch. 1/p. 1
- Ref: Exhibit 1/Tab 2/Sch. 2/p. 1

- Ref: Filing Requirements for Electricity Distribution Rate Applications[9] (section 2.7.3.6, page 31)

Board staff notes that API has committed $24,238 to the LEAP. Board staff also notes that the Board's Filing Requirements for Electricity Distribution Rate Applications point to a reasonable commitment being the greater of 0.12% of distribution revenue requirement or $2,000. Board staff further notes that this formula yields $28,111.

a) Please provide an explanation for API's LEAP commitment being lower than the recommended amount.
b) Please provide the trends in bad debt and arrears in API's service territory over the past five years. Does the trend support API's LEAP proposal?

28. 4Staff28 – Depreciation and Amortization

- Ref: Exhibit 4/Tab 12/Sch. 2 (Tax Calculations for 2015)
- Appendix 2-CU (Depreciation and Amortization Expense for 2015)
- Revenue Requirement Work Form ("RRWF") (Depreciation and Amortization)

The amount for depreciation and amortization in the Tax Calculations differs from the amount shown in the Depreciation schedule for 2015, and used in the RRWF.

a) Please provide an explanation for the difference.

29. 5Staff29 – Long-Term Debt Rate

- Ref: Exhibit 5/Tab 1/Sch. 1/p. 2
- Ref: Exhibit 5/Tab 1/Sch. 1/Appendix A/p. 28
- Ref: Exhibit 5/Tab 1/Sch. 2/Appendix 2-OA

9 http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Filing_Reqs_Dx_Applications_ch_1.2.3.5_20130717.pdf

Board staff notes API's long-term debt rate on unsecured notes is 5.118%, resulting in a Weighted Average Cost of Capital ("WACC") of 6.69%. Board staff further notes that Appendix 2-OA indicates a long-term debt rate of 5.15% resulting in a WACC of 6.71%.

a) Please provide an explanation for this apparent discrepancy.

30. 6Staff30 - Updated Revenue Requirement Work Form ("RRWF")

- Ref: Exhibit 6/Tab 1/Sch. 4/Appendix A

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

31. 6Staff31 - Revenue Deficiency

- Ref: Exhibit 6/Tab 1/Sch. 4/p. 1
- Ref: Exhibit 1/Tab 2/Sch. 2/p. 1
- Ref: Cost Allocation Model Excel File/Tab "O1 Revenue to cost RR"

In Exhibit 6, API calculates the revenue deficiency as the difference between "the 2015 Test Year revenue requirement of $24,708,794" and "the forecast 2015 Test Year revenue, based on 2014 approved rates, at $21,077,494".

Board staff notes that the distribution revenue requirement API is seeking is calculated as $23,426,431 in both Exhibit 1 and the cost allocation model. Board staff also notes that the distribution revenue at existing rates is calculated as $20,356,651 in the cost allocation model.

a) Please reconcile and explain the origins of the $24,708,794 (vs. $23,426,431) and $21,077,494 (vs. $20,356,651) numbers in Exhibit 6.

b) In the event these numbers are in error, please re-calculate the revenue deficiency using the correct numbers.

32. 7Staff32 – Seasonal Class and Street Lighting Class

- Ref: Exhibit 7/Tab 1/Sch. 2/p. 9
- Ref: Exhibit 7/Tab 1/Sch. 3/p. 2 - 3

API is proposing RC ratios of 55.03% and 24.66% respectively for the Seasonal and Street Lighting Class.

API states that as there is no Board policy range equivalent of the revenue-to cost (“RC”) ratio for API’s Seasonal class, by default API has assumed the same Board policy range as the Residential – R1 class, i.e. 85% to 115%.

Board staff notes in the tables pertaining to re-balancing RC ratios and Proposed RC ratios, the policy range indicated for the Seasonal class is 80% to 115%.

Board staff also notes that the Board’s policy range for the Street Lighting Class is 70% to 120%.

a) Please provide the rationale for proposing ratios outside the Board’s policy range for these two classes; and

b) Please confirm if the 80% to 115% range pertaining to the Seasonal class is an oversight.

33. 7Staff33 – Density Allocator

- Ref: Exhibit 7/Tab 1/Sch. 2/p. 7 - 8

API states: “the weighting of the density allocator has contributed to the re-distribution of costs among the customer classes as compared to the 2011 results.”

API also states: “the density weighting of the model may not appropriately reflect the reality of distribution costs apportioned at API”.

a) Please reconcile these two statements;

b) Please provide information and further details supporting the 2nd statement, i.e. density weighting of the model does not reflect reality of distribution costs; and

c) With respect to the cost allocation methodology, please explain what changes, if any, API has investigated to result in a more “realistic” allocation.

34. 7Staff34 – Cost Allocation Model Input

- Ref: Exhibit 7/Tab 1/Sch. 2/p. 7

API states: “The Cost Allocation Model asks the Applicant to provide the structure circuit length along highways as the input. The layout of API’s distribution system and spatial distribution of its customers in very rural and remote areas means that much of API’s distribution system is located off-road. In the previous cost of service review this input was left blank. In this Application, API has approximated the input required by the model by using its total length of line”.

a) Why has API input density information in the cost allocation model associated with this application but left it blank the last time?

b) Please provide a run of the cost allocation model for the 2015 test year that leaves the density information blank as in the previous cost of service review.

c) How does API estimate its total length of line?

35. 8Staff35 – Loss Factor

- Ref: Exhibit 8/Tab 2/Sch. 8/p. 2 -3

Board staff notes that API's proposed Total Loss Factor ("TLF") of 1.0917, i.e. 9.17% is 6.1% higher than its current Board-approved TLF of 1.0864, i.e. 8.64%.

Board staff further notes that included in the causes for this increase is the re-configuration of the distribution supply to accommodate maintenance to either the Echo River Transmission Station or the transmission supply to the Northern Avenue Station.

a) Please explain what steps if any API has taken to mitigate this situation in order to minimize distribution losses going forward, including any interim measures that can be implemented if capital investments are a longer term solution. Please also explain if any reductions in losses have been factored into a cost-benefit analysis that would support the advancement of any planned project.

36. 9Staff36 – Departure from Uniform System of Accounts – Account 1518 and 1548

- Ref: Exhibit 1/Tab 1/Sch. 10
- Ref: Exhibit 9/Tab 5/Sch. 1

API has stated that it does not track the variances in the Account 1518, Retail Settlement Variance Account – Retail and Account 1548, Retail Settlement Variance Account – Service Transaction Request.

According to the Accounting Procedures Handbook ("APH")[10]:

[10] http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Accounting_Procedures_Handbook_Elec_Distributors.pdf (Article 490, page 4)

A distributer must establish at least two variance accounts for the purpose of recording variances between reasonable costs incurred for the provision of retail services and the rates for these services in their Board-approved rate order. These are:

i. A Retail Cost Variance Account for Retail Services ($RCVA_{Retail}$), and
ii. A Retail Cost Variance Account for Service Transaction Requests ($RCVA_{STR}$)

a) Please provide an explanation for not following the APH.

b) Please quantify the estimated balances in Accounts 1518 and 1548 as of December 31, 2013, had Algoma followed the APH.

37. 9Staff37 – Account 1508 – Other Regulatory Assets – Ontario Clean Energy Benefit Sub-Account

- Ref: Exhibit 9/Tab 1/Sch. 1/p. 9
- Ref: EDDVAR Continuity Schedule for 2012 and 2013

The January 6, 2011 letter[11] of the Board with respect to Implementation of the Ontario Clean Energy Benefit (EB-2011-0009) stated the following:

The Board expects that any principal balances in "Sub-account Financial Assistance Payment and Recovery Variance – Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable. The Board also expects that any request for review and disposition of associated carrying charges will be addressed as part of a distributor's cost of service rate application and be subject to a prudence review at that time.

11 http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/ltr_OntCleanEnergyBenefit_Implementation_20110106.pdf

Board staff notes that API's Account 1508, Sub-account Ontario Clean Energy Benefit has continued to build credit balances in its account in 2012 and 2013 and the carrying charges recorded in 2012 were a debit amount.

a) Given the Board direction in the January 6, 2011 letter, why have credit balances been building in this account?

b) Why are the carrying charges a debit amount in 2012, while there was a large credit balance in this account in 2012/

38. 9Staff38 – EDDVAR Continuity Schedule

- Ref: EDDVAR Continuity Schedule

API is showing the following amounts in the columns titled Adjustments – Other:

	2011			
Account #	Adjustments Principal	Adjustments Interest	Directional Inconsistency between Principal and Interest	Total Adjustments 2011
1580	-$416,763	-$5,502		-$422,266
1584	$62,125	-$167	x	$61,958
1586	-$109,426	-$2,417		-$111,843
1588	-$1,294,882	$11,462	x	-$1,283,419
1589	$830,898	-$67,311	x	$763,587
1590	-$322,541	$122,448	x	-$200,093
	-$1,250,589	$58,514		**-$1,192,075**

	2012			
Account #	Adjustments Principal	Adjustments Interest	Directional Inconsistency between Principal and Interest	Total Adjustments 2012
1588	$314,012	$0	x	$314,012
1589	-$744,397	$46,051	x	-$698,346
1595	$66,872	$0	x	$66,872
	-$363,513	$46,051		**-$317,462**

	2013			
Account #	Adjustments Principal	Adjustments Interest	Directional Inconsistency between Principal and Interest	Total Adjustments 2013
1588	$179,041	$0	x	$179,041
1589	-$207,970	$0	x	-$207,970
	-$28,930	$0		**-$28,930**

a) Please provide explanations for the nature of the adjustments for all of the years noted above.

b) If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

c) Board staff notes that in many instances, the direction of the interest adjustment is not consistent with the principal adjustment. Board staff has marked these inconsistencies with ‘x’ in the Tables above. Please provide explanation for the adjustments where the sign on the interest is not consistent with the principal adjustment made.

39. 9Staff39 – Fixed Assets Continuity Schedule

- Ref: Exhibit 9/Tab 4/Sch. 2 (Appendix 2-BA1 for 2013 and 2014)
- Ref: Appendix 2-BA (Fixed Asset Continuity Schedules for 2013 and 2014)

- Ref: Exhibit 9/Tab 4/Sch. 3 (Appendix 2-EE)

Board staff notes that in the Fixed Assets continuity Schedule for 2014, the beginning balance is the closing balance from the Fixed Assets Continuity **before** the "Allocations" columns for both, cost and accumulated depreciation. The "Allocations" column has been added by API, but the reason for this adjustment has not been explained.

a) Please provide an explanation for the "Allocations" columns under "Cost" as well as under "Accumulated Depreciation".

b) Net additions under former CGAAP for 2013 and 2014 per Appendix 2-EE do not match the net additions per respective Appendix 2-BA1 for 2013 and 2014. Please explain the discrepancy.

c) Net depreciation under former CGAAP for 2013 and 2014 per Appendix 2-EE do not match the net depreciation per respective Appendix 2-BA1 for 2013 and 2014. Please explain the discrepancy.

d) Net additions under revised CGAAP for 2013 and 2014 per Appendix 2-EE do not match the net additions per respective Appendix 2-BA for 2013 and 2014. Please explain the discrepancy.

e) Net depreciation under revised CGAAP for 2013 and 2014 per Appendix 2-EE do not match the net depreciation per respective Appendix 2-BA for 2013 and 2014. Please explain the discrepancy.

40. 9Staff40 – Property, Plant & Equipment ("PP&E")

- Ref: Exhibit 9/Tab 4/Sch. 3 (Appendix 2-EE)
- Ref: OEB - 2012 Yearbook[12] of Electricity Distributors

[12] http://www.ontarioenergyboard.ca/oeb/_Documents/RRR/2012_Electricity_Yearbook.pdf

The Opening net PP&E per Appendix 2-EE does not match the 2012 ending net PP&E reported by API under RRR 2.1.7, and published by the Board in the 2012 Yearbook.

Opening Net PP&E 2013 per Appendix 2-EE	$80,883,969
Closing Net PP&E 2012, per 2012 Yearbook	$81,495,181

a) Please explain the discrepancy.

41. 9Staff41 – Funding Variance

- Ref: Exhibit 9/Tab 8/Sch. 1 (including Appendix A)

API's predecessor GLPL collected annually, $2,333,808 from the RRRP pool of funds for 2002 to 2007 as per the Board's Rate Order RP-2003-0149. API is seeking $173,534 which it accrued as an accounts receivable for the difference between what GLPL collected from Hydro One for RRRP and what GLPL credited its customers from 2002 to 2007.

GLPL appealed the Board's decision, EB-2007-0744, dated October 30, 2008. The Board's decision was upheld at Divisional Court, Court of Appeal for Ontario and further appeal was dismissed by the Supreme Court of Canada.

Fortis bought GLPL's distribution business on October 9, 2009. API's cost of service rates were set by the Board on a final basis effective December 1, 2010. API has had its rates set on a final basis by IRM for 2012 and 2013. The Board issued a decision on February 20, 2014 which approved rates on a final basis.

In its Decision on API'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. The rates for all other customer classes not eligible for RRRP would be adjusted by the price cap adjustment index.

a) Table 9.8.1.1 of the evidence shows that API received the exact RRRP in accordance with the Board's Rate Order. As this was part of the revenue requirement, which is not subject to true-up, what is API's justification for this proposal?

b) Please comment on API's proposal for recovery of amounts that pre-date its purchase of the distribution business from GLPL given the impermissibility of retroactive ratemaking.

c) Please explain why any amounts arising from the period prior to API's first rate order in 2010 should be considered by the Board given that rates are set on a final basis by the Board

d) Did API seek the Board's approval for a deferral account to record these amounts for recovery from the rate payers?

e) Why did API not seek the Board's approval to address this issue in its previous Cost of Service application?

42. 9Staff42 – Disposition Period

- Ref: Exhibit 9/Tab 6/Sch. 1/p. 3

Board staff notes that API is assuming a 1-year period for disposition of the credit balance in Deferral/Variance accounts and debit balance in the Global Adjustment Sub-Account.

a) Please explain why API did not consider a 2-year disposition period to mitigate rate volatility.

b) Please provide a table outlining bill impacts attributable to rates riders for the disposition of Deferral/Variance accounts and the Global Adjustment Sub-Account assuming both a 1-year and 2-year disposition period.