August 7, 2014

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

Dear Ms. Walli:

RE: 2015 ELECTRICITY DISTRIBUTION RATE APPLICATION FOR ALGOMA POWER INC. ("API") – EB-2014-0055
INTERROGATORY RESPONSES

Please find accompanying this letter, two (2) copies of the API's responses to interrogatories posed by Board staff and the intervenors. Co-incidentally with the submission, an electronic copy of these responses along with requested Excel Worksheets have been filed via the Board's Regulatory Electronic Submission System.

If you have any questions in connection with the above matter, please do not hesitate to contact the undersigned at (905) 994-3634.

Yours truly,

Original signed by:

Douglas R. Bradbury
Director, Regulatory Affairs

Enclosures

(page left blank intentionally)

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.

RESPONSE:

As of the date of this interrogatory, July 21, 2014, API has not received any letters of comment in respect of this Application.

a) Not applicable

b) Not applicable

(page left blank intentionally)

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.

RESPONSE:

a) As stated in Exhibit 8 Tab 2 Schedule 6 page 1, API does not have any rates or charges reflected in its Conditions of Service.

b) Not applicable

c) Not applicable

(page left blank intentionally)

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).

RESPONSE:

a) The only interrogatory posed which has resulted in a modification to Appendix 2-W, Bill Impacts is 8.0 – VECC – 41. In part c) of this Interrogatory, VECC pointed out that API had not included the 2013 Rate Rider for Foregone Revenue (2013) – effective until December 31, 2014 in its bill impact calculation.

The impact of including the Rate Rider for Foregone Revenue (2013) – effective until December 31, 2014 is very minor and has the result of lowering the total bill impact by tenths of a percent.

An updated Bill Impact Model accompanies these interrogatory responses.

(page left blank intentionally)

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.

RESPONSE:

a) API has been undertaking enhanced engagement activities for at least 10 years. As described in Exhibit 1, Tab 3, Schedule 1, API uses a number of engagement opportunities to seek an alignment between customer needs and API's operational and capital plans, including: bill inserts; annual meetings with large customers; an annual customer survey and annual municipal stakeholder meetings. API is continuously looking to further enhance its customer engagement, as well as enhancing its agendas each year as a way to provide continuous improvement in this process for our customers. Some of the more recent improvements to API's enhanced customer engagement are as follows:

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

i) API has introduced the customer satisfaction survey in 2010 as a tool to determine satisfaction on a number of key service outcomes. The survey results have provided support for the implementation of an Outage Management System to provide more accurate and timely response to outages.

ii) API determined during a number of Municipal Stakeholder Meetings that municipal infrastructure upgrades and utility infrastructure renewals could be better coordinated based on specific feedback. For the past few years, API has been meeting separately with municipal roads managers to align municipal work with that of the utility in the same areas. This has reduced costs to both the utility and the municipalities since the coordination has minimized the chances and expenses of duplicating the same work.

iii) API remains diligent in promoting and engaging customers through its CDM programs. A variety of outreach efforts have been deployed including the placement of ads in municipal publications, marketing material displays in keys areas of all municipalities and community outreach events and Home Shows. These events are attended by a combination of both CDM and customer service staff providing an opportunity to interact with customers at a grassroots level.

API will continue to look for ways to enhance engagement between distributors and their customers to provide better alignment between its operational plans and customer needs and expectations

b) See answer to a) above.

5. 1Staff5 – Reflecting Customer Needs in the Application

- 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, "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.

RESPONSE:

API employs many forms of customer engagement as described in Exhibit 1, Tab 3, Schedule 1. In addition, API has described some more specific examples of this in its answer to 4Staff21.

---

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

(page left blank intentionally)

Algoma Coalition
Embedded Distributor

1. Please explain the effect that the Dubreuil Forest Products Ltd. embedded distributor has on other Algoma Power Inc. (hereinafter “Algoma Power”) customers.

RESPONSE:

Dubreuil Forest Products Ltd. has a Distribution Licence, ED-2012-0074, issued to Dubreuil Lumber Inc. For the purposes of rate design and customer billing, the embedded distributor has been designated as a Residential – R2 customer. This designation allows RRRP funding to be associated with the customer.

This customer has no effect on the remainder of API’s customers. The cost allocation apportions costs to each customer class equitably and electricity distribution rates are designed to recover these class apportioned costs equitably from all customers within each classification.

(page left blank intentionally)

Algoma Coalition
New Connections

2. We understand Argonaut Gold Inc. will be a major new connection. Please explain whether there have been expenditures in anticipation of this new connection, and, if so, confirm the level of such expenditures.

RESPONSE:

API is unable to disclose personal information about existing customers or prospective customers. However, API can disclose that it has not made any expenditures in anticipation of any large prospective customers.

(page left blank intentionally)

Algoma Coalition
New Connections

3. Please confirm and explain whether there is anything in the present rate application that accommodates new connections similar to Argonaut Gold Inc. to avoid such connections affecting other Algoma Power customers.

RESPONSE:

There are no projects identified in the Application similar to that described in this Interrogatory.

(page left blank intentionally)

<u>1-Energy Probe-1</u>

Ref: Exhibit 1, Tab 1, Schedule 16

Please confirm that there are not costs included in the test year revenue requirement associated with the Board of Directors of any of the affiliates shown on page 1. If this cannot be confirmed, please provide the amount included in the test year and the amounts included in the historical and bridge years.

RESPONSE:

There are no Board of Directors costs from any of the affiliates included in the revenue requirement.

(page left blank intentionally)

<u>1-Energy Probe-2</u>

Ref: Exhibit 1, Tab 2, Schedule 1

When does API expect that the Board will determine the appropriate RRRP Adjustment Factor during this proceeding?

RESPONSE:

On the basis of past practice and consistent with recent incentive rate-setting applications, Board staff will determine the RRRP Adjustment Factor for use in preparing the Draft Rate Order.

(page left blank intentionally)

1.0 – VECC - 1

Reference: E1/T2/S6/pg.1

a) Please provide the CPI and GDPI assumptions used by API for the years 2011 through 2015. Please provide the source of these assumptions.

RESPONSE:

The Company relies upon the HayGroup guidance and collective agreements in determining employee compensation increases. Non-labour amounts are forecasted using a 2 per cent inflationary rate. API sets this rate based on the Bank of Canada's monetary policy aimed at keeping inflation at 2 per cent.

According to the Bank of Canada, the CPI for previous periods are as follows;

- 2014 - 2.4% (June year over year)
- 2013 - 1.2%
- 2012 - 0.8%
- 2011 - 2.3%
- 2010 - 2.4%

(page left blank intentionally)

1.0-VECC-2

Reference: E1/T3/S1/pg.2

a) Please provide the most recent customer survey and the detailed results?

RESPONSE:

Attached is the 2013 customer survey Final Report.

(page left blank intentionally)

FORTIS ONTARIO

2013 Customer Satisfaction Study
Algoma Power

Final Report

December 2013

CRA
CORPORATE RESEARCH ASSOCIATES

Accredited Gold Seal Corporate Member

5001-7071 Bayers Road | Halifax NS B3L 2C2
T 902.493.3820 | F 902.493.3879 | W www.cra.ca

2013 Customer Satisfaction Study
Algoma Power

Final Report

Confidential

Reproduction in whole or in part is not permitted without the expressed permission of **FortisOntario Inc.**
FOR001-1007

Prepared for:

FortisOntario Inc.

December 2013

CORPORATE RESEARCH ASSOCIATES

Table of Contents

Page

Introduction

FortisOntario Inc. is a member of the Fortis Inc. group of companies and owns Canadian Niagara Power Inc. ("CNP"), Cornwall Electric and Algoma Power Inc., which it acquired in October 2009. With FortisOntario operating in a competitive environment, it is important for the company to gauge satisfaction among its customer base. Such research provides FortisOntario with the opportunity to assess in what areas it, as a company, is performing well, but more importantly, it allows for the early identification of potential problem areas. Identifying areas where customer satisfaction is less than optimal permits FortisOntario to implement actions to address these issues before they become problematic.

FortisOntario has commissioned Corporate Research Associates Inc. (CRA) to conduct its annual Customer Satisfaction Study for its various utilities, including Algoma Power Inc. to provide a base line measure for customer opinion going forward in that region. The primary objective of the **Customer Satisfaction Study** is to provide an annual quantitative measurement of customers' perceptions and attitudes. More specifically, the study seeks to:

- Determine overall satisfaction with the quality of service provided by Algoma Power Inc.;
- Determine overall satisfaction with the reliability of the service provided;
- Measure customers' satisfaction with the quality of customer service;
- Assess customer perceptions of bill inserts in addition to preferred methods of receiving similar forms of information; and
- Examine customers' awareness of Algoma Power's Conservation & Demand Management programs.

The following report presents results of the **2013 Customer Satisfaction Study for Algoma Power** and includes an executive summary, a detailed analysis of the survey findings, and a description of the methodology employed in the conduct of the study. The report provides a comparison of results since 2010. Appended to the report is a copy of the study questionnaire (Appendix A), banner tables that present the results for each question by demographic characteristics (Appendix B), and verbatim comments (Appendix C).

Of note, data tables for each question present results of only customers with an opinion on each respective question (i.e., 'don't know/no answers' are excluded). As such, the sample size will fluctuate slightly by question. All tables in the report are noted by number for easy reference. Unless otherwise noted, all results in this report are expressed as a percentage.

©Corporate Research Associates Inc., 2013

Executive Summary

Results of the **2013 Customer Satisfaction Study** reveal that Algoma Power receives high reviews for most customer services provided, although a number of opportunities for improvement are evident.

Overall, scores continue to be strong with respect to the Utility's ***timely and accurate customer billing, reliable and safe delivery of electricity,*** and ***keeping customers informed about changes in the electricity industry***. However, overall ratings for ***restoring power in a timely manner*** have declined this year compared to 2012***.***

Evaluation Algoma Power's communications services have also declined on a number of key attributes. Specifically, customers are less likely to give the Utility positive ratings with respect to the ***provision of timely and reliable information during power outages***. Ratings have also declined with respect to the Utility's ***response to customer questions or concerns*** compared with last year.

This year, significantly fewer customers were likely to have experienced a power outage in the three months prior to being surveyed, most of whom experienced an unplanned outage. Consistent with last year, nearly all of those who experienced a planned outage were pre-notified of the event. A minority of such customers contacted Algoma Power for information related to an outage, and most were satisfied with how their request was handled by a customer service representative.

When asked how they would like to receive information from the Utility during a power outage, customers continue to voice a clear preference for the ***telephone***, either as a direct contact or via an ***automated voice message*** to their household.

Awareness of Algoma Power's Energy Conservation & Efficiency Programs has declined significantly this year. Indeed, only four in ten customers report being aware of the saveONenergy initiatives, mostly as a result of information on bill inserts. Indeed, there is clearly an opportunity to enhance customer awareness in this regard. Customers continue to look for time-of-use ***rate schedule*** information and their detailed ***electricity consumption*** amount by time-of-use block on their electricity bill.

Finally, when presented with details of the new Time-of-Use Web Presentment tool, a majority of respondents express interest in learning more about the application. This presents an excellent opportunity for Algoma Power to enhance the provision of customer information.

©Corporate Research Associates Inc., 2013

Detailed Analysis

Overall Satisfaction

Customers continue to be highly satisfied with Algoma Power's quality of service.

The level of customer satisfaction with the quality of service provided by Algoma Power continues to be strong. More specifically, one quarter of customers express 'complete' satisfaction, while about half indicate being 'mostly' satisfied and a further two in ten consider themselves 'somewhat' satisfied. Dissatisfaction is minimal, with just five percent of customers being 'not very' satisfied and two percent being 'not at all' satisfied. (Table 1)

The small number of sampled customers who are dissatisfied (n = 14) were asked why they are not satisfied with the quality of service provided by Algoma Power, in order to understand the source of their dissatisfaction. Dissatisfaction is generally attributed to power outages (planned or unexpected), customer service, delivery charges, Time-of-Use pricing, and the price of electricity. (Table 1b)

©Corporate Research Associates Inc., 2013

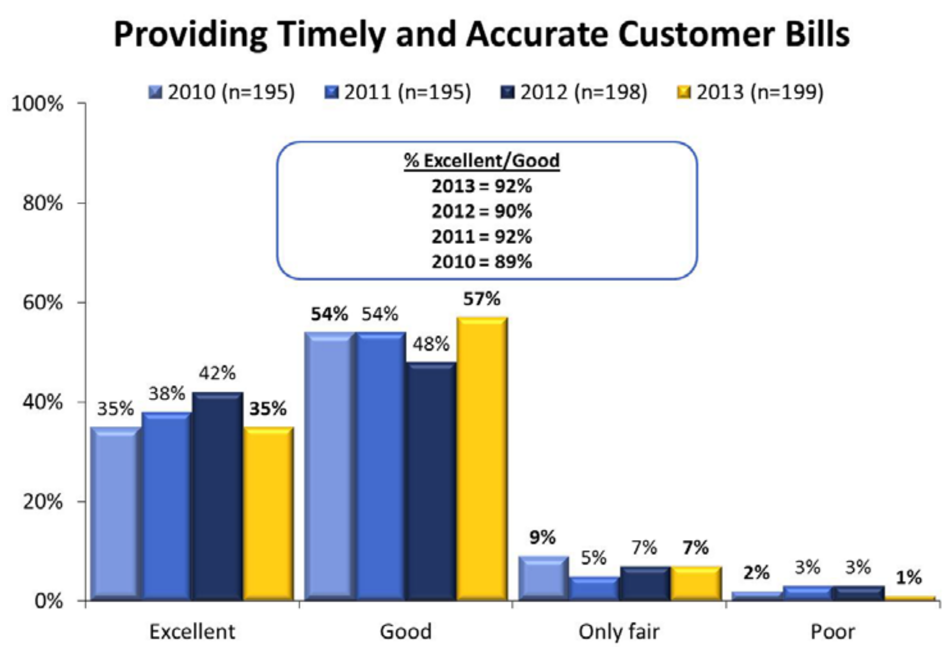
Service Delivery

Algoma Power's service delivery processes continue to be well rated by customers, although perceptions of its timely power restoration and provision of information during outages have declined.

Feedback on six specific activities pertaining to Algoma Power's service delivery process was assessed, including: *the reliable and safe delivery of electricity, restoring power in a timely manner in the event of power outages, providing timely and reliable information during power outages, the Utility's response to customers' questions or concerns, the timeliness and accuracy of customer bills* and *keeping customers informed about changes in the electricity industry.*

Favourable ratings are observed on most aspects of Algoma Power's service delivery process, although customers' opinions have declined for both ***restoring power in a timely manner***, and ***providing timely and reliable information during power outages***.

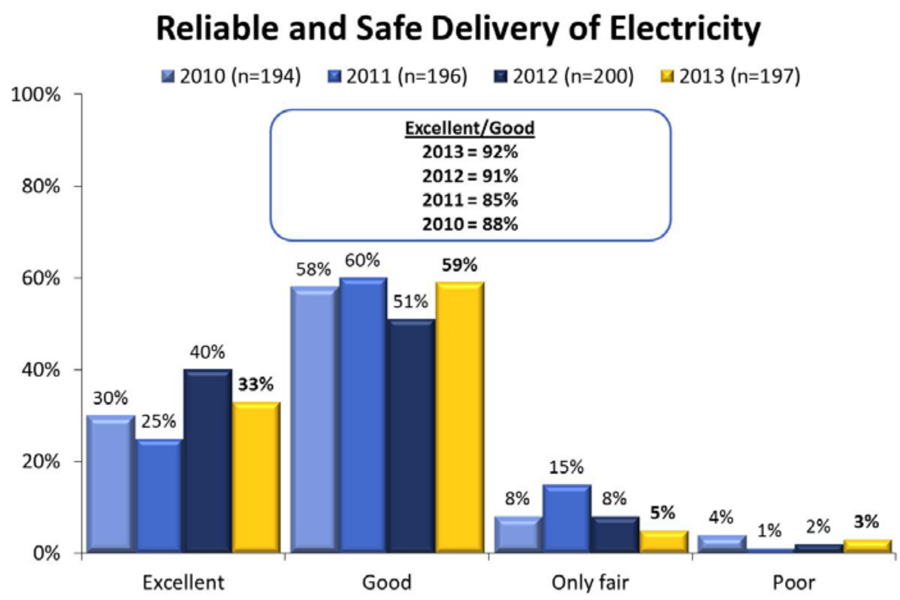
Provision of timely and accurate bills continues to be rated highly, with the vast majority of customers offering positive feedback. It should be noted that ratings of 'excellent' performance have slightly declined this year (7 points), although not to a significant extent. That said, an increased rating of 'good' keep the overall ratings high, resulting in the higher positive reviews since last year. (Table 3e)



Q.3e: I would like you to tell me if you think Algoma Power does an excellent, good, only fair, or a poor job of providing the service. To begin, how would you rate Algoma Power with respect to: Providing timely and accurate customer bills.

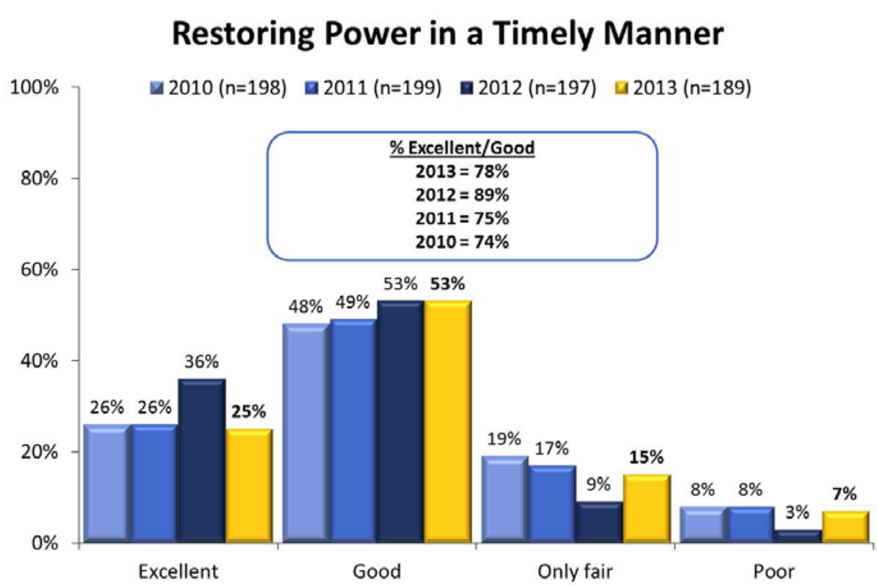
©Corporate Research Associates Inc., 2013

Overall positive opinions of Algoma Power's ***provision of reliable and safe delivery of electricity*** have remained stable this year, despite the fact that customers are more inclined to give 'good' ratings to the Utility rather than 'excellent' ratings. (Table 3a)



Q.3a: I would like you to tell me if you think Algoma Power does an excellent, good, only fair, or a poor job of providing the service. To begin, how would you rate Algoma Power with respect to: Providing reliable and safe delivery of electricity to local homes and businesses.

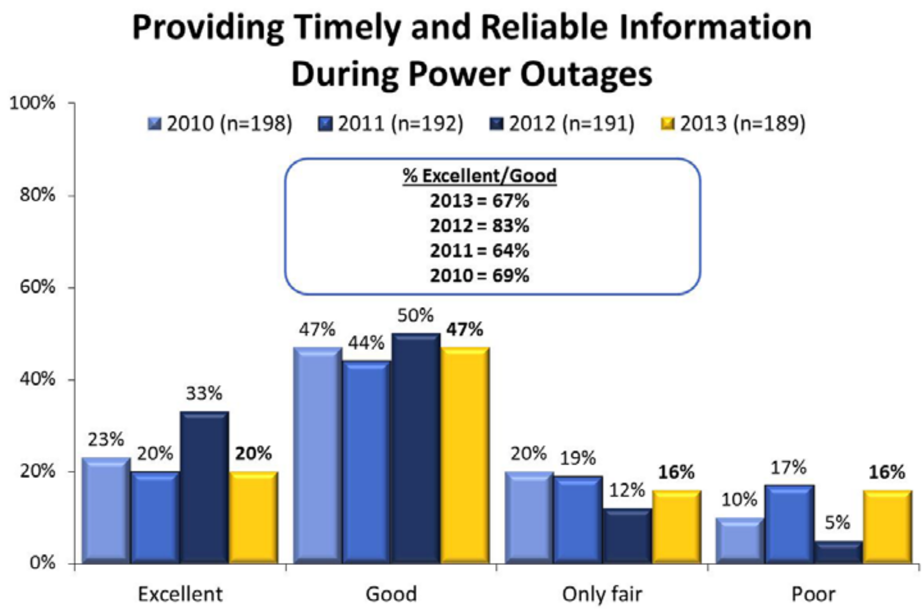
On the other hand, concerning Algoma Power's ***restoration of power in a timely manner***, customers are significantly less likely to give positive ratings this year compared with 2012. Indeed, more than two in ten customers consider the Utility's performance to be only fair or poor in this regard. (Table 3c)



Q.3b: I would like you to tell me if you think Algoma Power does an excellent, good, only fair, or a poor job of providing the service. To begin, how would you rate Algoma Power with respect to: Restoring power in a timely manner in the event of power outages.

Perhaps not surprisingly, customers who express higher degrees of satisfaction with the *quality of service* provided by Algoma Power are also more likely to provide positive ratings on each of the above mentioned service delivery attributes.

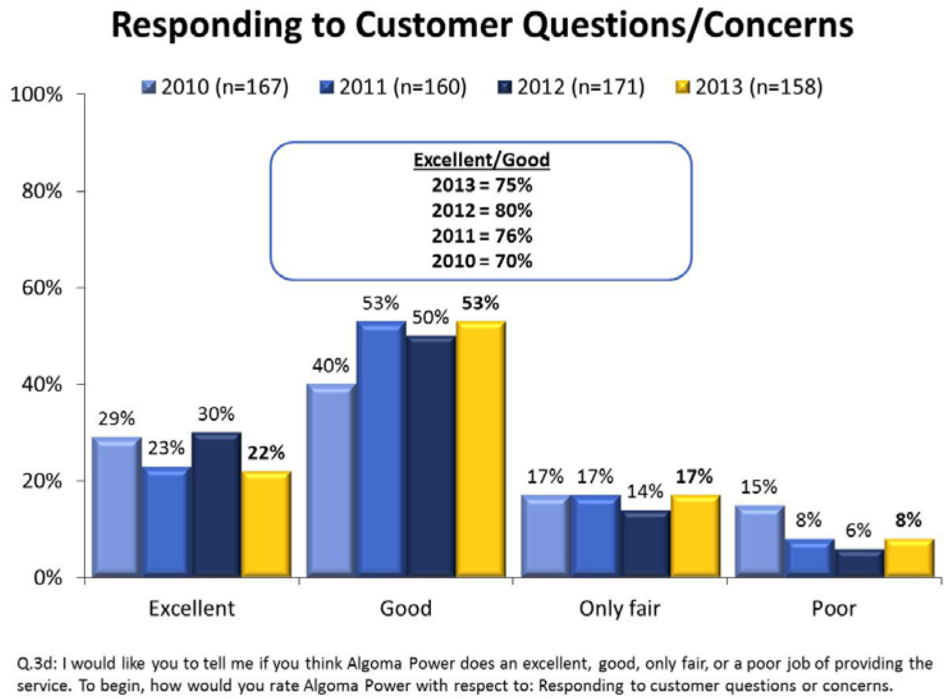
Evaluations of Algoma Power's communications efforts during an outage have not improved this year. In fact, customers are significantly less likely to rate Algoma Power's ***provision of timely and reliable information during power outages*** positively compared with last year, though the majority provided ratings of excellent/good (67%; down 16 points). Also, there has been a significant increase in the rating of 'poor' this year compared to last. (Table 3c)



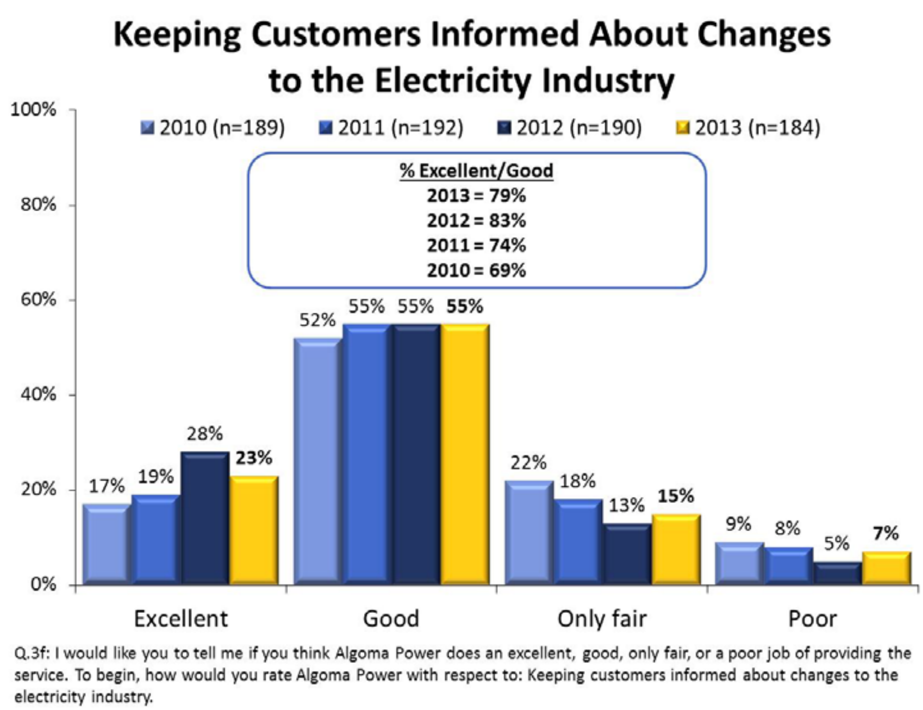
Q.3c: I would like you to tell me if you think Algoma Power does an excellent, good, only fair, or a poor job of providing the service. To begin, how would you rate Algoma Power with respect to: Providing timely and reliable information during power outages.

Additionally, Algoma Power's performance in ***responding to customer questions or concerns*** has slightly declined since last year. Specifically, two in ten customers gave a score of 'excellent', a decrease compared to 2012 but in line with 2011 results, while over one half of customers view the Utility as 'good' in that regard, a marginal increase from last year. Both ratings of 'only fair' and 'poor' have increased marginally compared with 2012 results. (Table 3d)

©Corporate Research Associates Inc., 2013



This year, results for Algoma Power's ability to ***keep customers informed about changes to the electricity industry*** remains strong. Consistent with historical findings, more than one half rated the Utility as 'good' in this regard, and over two in ten customers believe that Algoma Power is doing an excellent job at keeping customers informed about changes to the electricity industry. In addition, a slight increase in both 'only fair' and 'poor' ratings is evident this year, though to an insignificant degree. (Table 3f)



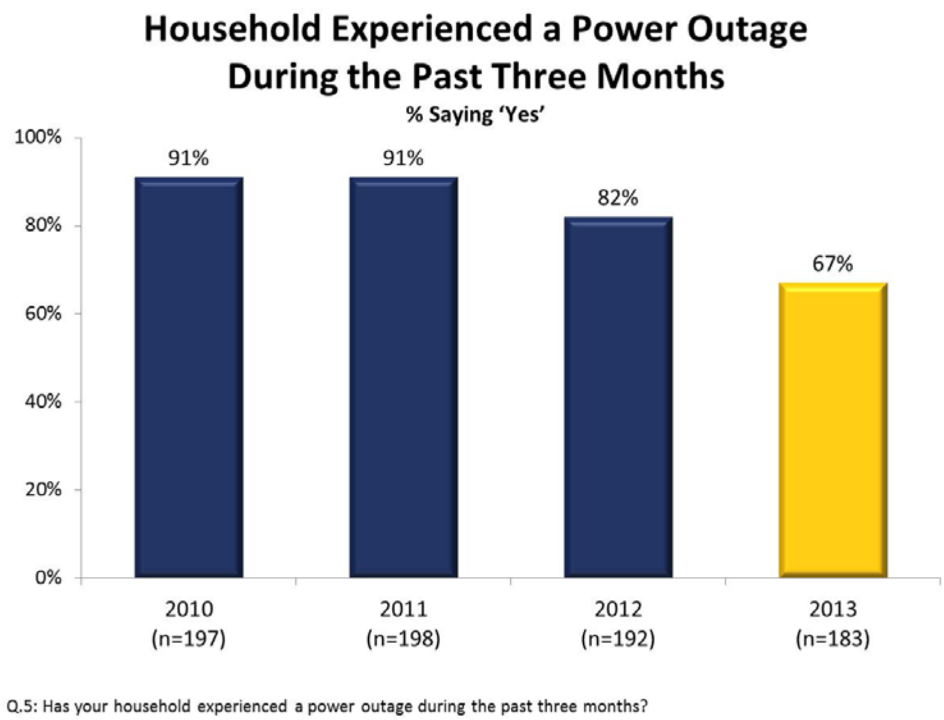
Results indicate that customers who express higher levels of satisfaction with Algoma Power's quality of service also rate the Utility more favourably on its communications efforts.

Power Outages

Customers are less likely to have experienced a power outage this year. Communication via telephone is still largely preferred by customers.

In an effort to understand customers' experiences with power outages and how they would prefer to receive information in the event of an outage, a series of questions were asked on this specific topic area.

This year, a significantly smaller proportion of customers experienced a power outage during the three months prior to the survey, although this group is still comprised of the majority of customers. (Table 5)



Among the customers who have experienced at least one power outage in the past three months, the majority (74%) indicate that it was an **unplanned outage**, while about two in ten (15%) reported that it was a **planned outage**. (Table 5a)

Nearly all of the customers who experienced a planned outage (n=32) said they were pre-notified of the event (94%). The vast majority of these customers were satisfied with the communication of the planned outage (93%). (Tables 5b-c)

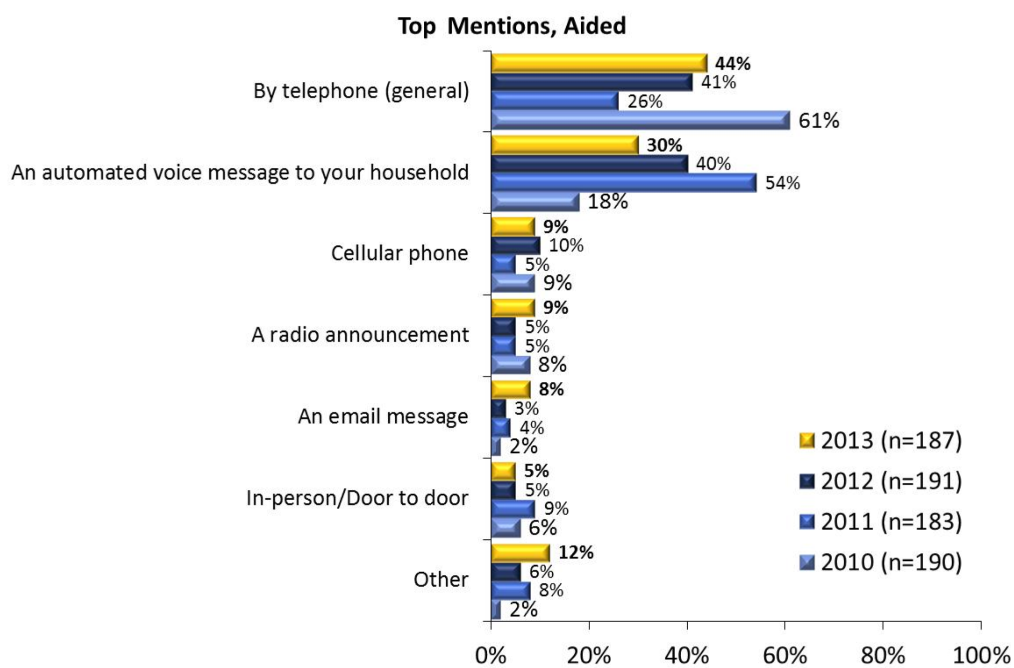
©Corporate Research Associates Inc., 2013

An increase from last year, three in ten (29%) customers who experienced an outage contacted Algoma Power regarding the issue. Most of them (85%) spoke with a customer service representative. The small number who did not speak to a representative (n=5) indicated that they did not do so because they dealt with *an automated system notifying* them of the outage, the *line was busy*, or they dealt with *an answering or service machine*. (Tables 6a, 6b, and 6d)

In particular, the number of customers who were in contact with a customer service representative has increased significantly, and this year they continue to be satisfied with the service they received during this call. Specifically, customers were either completely (48%) or mostly (30%) satisfied with the representative's service provision, while almost two in ten were somewhat satisfied (19%). (Table 6c)

To determine the methods by which Algoma Power could best reach customers to provide them with information during a power outage, all customers were asked to indicate, unaided, what the most effective way to reach them would be. There continues to be a clear preference for contact via the ***telephone*** (in general) or an ***automated voice message to customers' household***. No more than one in ten customers mentioned any of the other options, including by *cellular telephone*, *in-person door-to-door*, via *radio announcement*, through *an email message*, by leaving a *recording on the utility's answering service*, by posting a *bulletin on the website* or via the *internet* and by *mail* in general. (Table 6e)

Preferred Method of Receiving Information



Q.6e: If Algoma Power needed to provide information to its customers during a power outage, what would be the most effective way to reach you?

©Corporate Research Associates Inc., 2013

Quality of Customer Service

Algoma Power's quality of customer service continues to be highly rated by customers.

Consistent with results reported in 2012, the vast majority of customers continue to be pleased with Algoma Power's quality of customer service this year. Opinions of the quality of customer service have remained stable over the past two years, with just over one quarter giving a rating of 'excellent' while over one half consider the service to be 'good'. The proportion of customers who view the service as 'only fair' or 'poor' has remained low. (Table 4)

Q.4: How would you describe your overall opinion of the quality of customer service provided by Algoma Power? Would you say it is excellent, good, only fair, or poor?

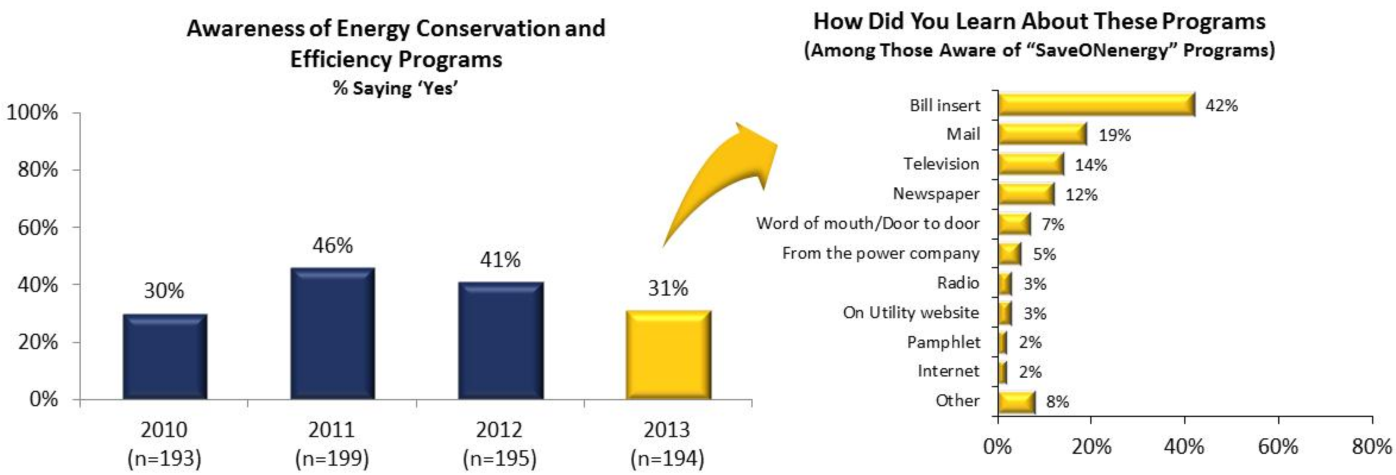
Similar to differences noted earlier, customers who report being completely or mostly satisfied with Algoma Power's quality of service are more likely than those less satisfied to perceive the Utility as providing a high standard of customer service overall.

Conservation & Efficiency Programs

Awareness of Algoma Power's saveONenergy initiatives has declined year-over-year, although bill inserts remain the primary information source for the programs.

Algoma Power offers Energy Conservation & Efficiency incentives to all customers through the "saveONenergy" program. To better assess customers' awareness and understanding of such programs, a series of questions were asked on this topic area.

Awareness of Algoma Power's Energy Conservation & Efficiency programs has significantly declined since last year, (31%, down 10 points). Customers continue to report learning about these programs through a variety of sources, with ***bill inserts***, ***mail***, and ***newspaper*** being primary information sources. No additional sources were cited by customers this year. Sources that appear to be less effective in heightening program awareness include *radio, internet, Algoma Power's website* or the *pamphlet*, as they were cited by less than one in ten respondents. (Tables 8a and 8b)

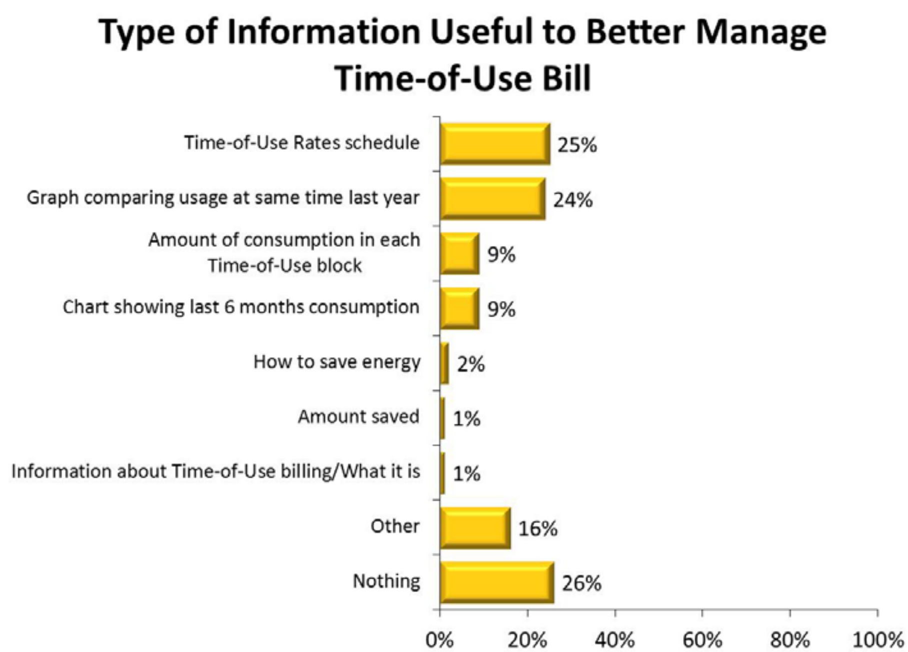


Q.8a: Eastern Ontario Power offers conservation & efficiency incentives through the new "saveONenergy" programs. Are you aware of any of these programs?

Q.8b: [IF YES IN Q8A] How did you learn about these programs? (n=59)

Time-of-Use Billing

Nine in ten respondents indicated they find the Time-of Use billing information to be useful. Customers were also asked what type of information would be most helpful to have on their power bill regarding this new feature. Among those who offered an opinion (n=85), ***time-of-use rate schedule*** is requested by one quarter of respondents, and the same proportion mentioned a ***graph comparing usage at same time last year*** would be useful to better manage the Time-Of-use bill (24%). All other topics are each suggested by fewer than one in ten customers, including amount of consumption in each Time-of-Use block, a chart showing last 6 months of consumption, and how to save energy. (Table 6h)

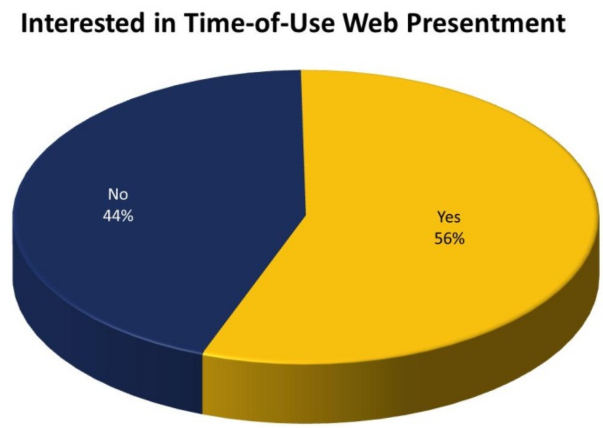


Q.6h: What type of information would be useful for you to better manage your Time-of-Use bill? (n=85)

New this year, Algoma Power customers were provided a description of the Time-of-Use Web Presentment tool, stated to be a quick and easy way to electricity consumption and cost information. Through this new tool, customers would have access to information about the usage and costs can be viewed at multiple levels of detail (e.g. hourly, daily, monthly, bill period) in a variety of graphical and tabular formats. Bill predictions can be viewed and usage and cost alerts can be set up to help the customer in monitoring and managing your electricity consumption. (Table 6i)

Customers were asked to share their level of interest in the tool. Notable interest is indicated, with just over half of respondents indicating the tool would be of interest to them.

©Corporate Research Associates Inc., 2013

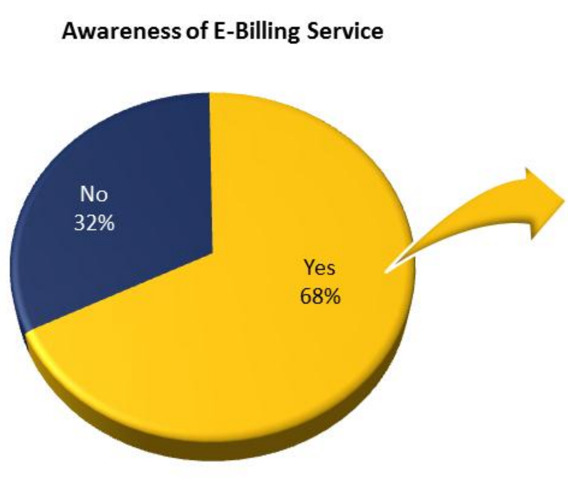


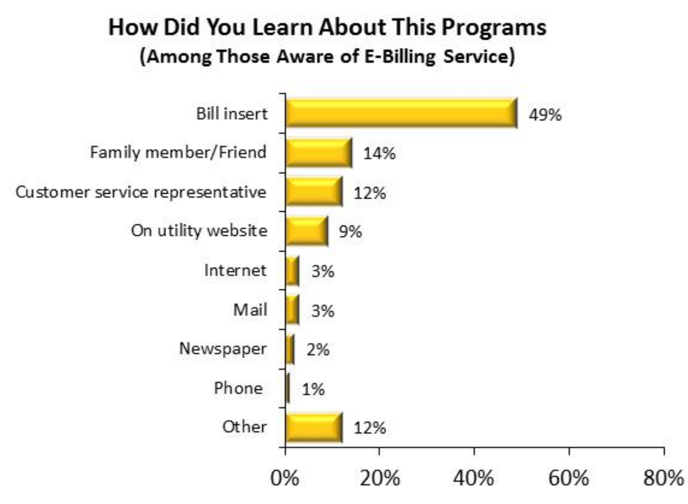
Q.6i: Algoma Power is now offering Time-of-Use Web Presentment. This tool provides quick and easy access to electricity consumption and cost information. You can view your usage and costs at multiple levels of detail (e.g. hourly, daily, monthly, bill period) in a variety of graphical and tabular formats. You can also view bill predictions and set up usage and cost alerts to help you in monitoring and managing your electricity consumption. Is this something that would interest you? (n=165)

E-Billing

A new series of questions were asked of Algoma Power's customers to gauge awareness of the e-billing service. Those who are aware were also asked how they learned about the alternative billing option. Results show that the majority of customers are aware that their Utility provider offers e-billing, with just under a third of customers who were previously unaware (32%).

Awareness was most commonly attributed to bill inserts by nearly half of the group (49%), while a smaller portion of customers learned about e-billing through a family member/friend (14%), or through a customer service representative (12%). A few customers also mentioned that they were made aware of e-billing through the Utility's website, via the internet, mail, in the newspaper, or over the phone. (Table 7a-b)





Q.7a Are you aware that Algoma Power offers an e-billing service? (n=192)

Q.7b: [IF YES IN Q7A] How did you learn about this programs? (n=113)

Study Methodology

Questionnaire Design

The survey questionnaire used for this study was provided to CRA by FortisOntario with minor modification. Prior to being finalized, the questionnaire was pre-tested on a small sample of respondents to ensure the appropriateness of the questions and response categories. A final copy of the questionnaire is attached as Appendix A.

Sample Design and Selection

The sample for this study was designed to complete interviews with a representative sample of 200 Algoma Power residential customers. The sample was drawn from a current database of Algoma Power customers provided to CRA specifically for this study. All customers included in the database were considered eligible for participation in the study. Up to five call backs were used to reach selected respondents who may not have been available at the time of the call, to ensure an appropriate distribution across gender and age levels.

Survey Administration

The survey was conducted by telephone between November 4th and 24th, 2013 from data collection facilities in Ontario. Fully trained and supervised interviewers conducted all interviewing and a minimum of ten percent of all completed interviews was subsequently verified. The average length of time required to complete an interview was approximately 8 minutes.

Given the total population of Algoma Power customers, a sample of 200 drawn from this population would be expected to produce results accurate to within plus or minus 6.8 percent in 95 out of 100 samples. The margin of sampling error will be greater when analyzing the data by demographic characteristics (i.e., gender).

©Corporate Research Associates Inc., 2013

Completion Results

Among all eligible respondents contacted, the rate of interview completion was 22 percent. Completion rate is calculated as the number of cooperative contacts (200) divided by the total of eligible numbers attempted (920). The final disposition of all telephone numbers called is shown below.

	2013	2012	2011
Total Numbers Attempted	**1025**	**1519**	**1363**
Not in Service/ Disconnected	97	138	83
Fax/Modem/Cell/Pager	1	3	4
Non-residential number	1	12	2
Wrong number	6	30	38
Blocked number	0	0	2
Duplicates	0	0	0
Total Eligible Numbers	**920**	**1336**	**1234**
Busy	17	21	28
Answering machine	217	474	318
No answer	157	229	327
Selected/Eligible respondent not available/Call backs	204	232	240
Language problem	0	5	7
Illness/Incapable	0	2	1
Total Asked	**325**	**373**	**312**
Refusal/ Hang up	0	156	97
Terminated	5	10	10
Do Not Call List	28	4	3
Cooperative Contacts	**205**	**203**	**201**
Disqualified (sensitive occupation/landlord pays)	5	3	0
Moved – served by different utility	0	0	0
Completed Interviews	**200**	**200**	**200**
Response Rate	**22%**	**15%**	**16%**

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.

RESPONSE:

a) The reason for the year-over-year percentage increases in rate base is that the total capital expenditures for each year exceed the depreciation expenses by an average of $5.6 million. Please refer to API's response to 2-Staff-16(f) for details on capital vs. depreciation. The largest contributors to the total annual capital expenditures in these years are:

i. Completion/continuation of major projects and programs approved in API's previous cost of service application (Conductor Replacement, Line Rebuilds, ROW Expansion)
ii. Completion of API's SAP migration in 2012
iii. Capitalization of smart meter costs in 2013
iv. Customer demand work related to new service connections and upgrades

(page left blank intentionally)

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?

RESPONSE:

a) Pages 3-5 of Exhibit 2, Tab 3, Schedule 2 provide details on the variances by project/program that contributed to the overall under expenditure in these years.

b) The majority of the 2010 under expenditure is a direct result of the timing of capitalization of GEC amounts. It should be noted that GEC amounts are no longer included in API's capital expenditure forecast due to changes in capitalization policy as described in Exhibit 2, Tab 4, Schedule 1. Approximately 1/3 of the 2011 under expenditure is attributed to delays in API's SAP implementation, as described in pages 4-5 of Exhibit 2, Tab 3, Schedule 2. This was a one-time event that is not expected to have any impact on future projects or programs. Approximately 2/3 of the 2011 under expenditure is attributed to delays in acquiring property rights related to certain conductor replacement projects and the Bellevue Valley project. Processes that have been put in place to ensure that project estimates are realistic and that the annual capital program remains on track are detailed in Section 5.2.3 (a) of API's Distribution System Plan, under the heading "Cost Efficiency and Effectiveness With Respect to Planning Quality and DS Plan Implementation".

c) API strives to ensure that all of its expenditures are prudent.

d) As a result of the consideration of rate impacts, API has presented a Distribution System Plan that is based largely on investments related to sustaining asset replacement and meeting mandated service obligations. With the exception of the Echo River TS upgrade project in 2017, capital expenditures presented in the 2015-2019 plan are relatively consistent year over year, and represent an overall declining trend as compared to API's historical 2010-2014 capital expenditures. API's response to 2-Staff-13(a) provides specific examples of how the consideration of rate impacts were included in API's Distribution System Plan.

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[1] 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.

RESPONSE:

a) The $331,640 represents the sum of Scenario A ($291,922) and Scenario B ($39,718) as at December 31, 2012. The $278,026 represents the sum of Scenario A ($238,308) and Scenario B ($39,718) balances requested for disposition projected to December 31, 2014. The difference of $53,614 is the depreciation expense calculated for 2013 ($27,302) and 2014 ($26,312) in Scenario A.

	Scenario A	Scenario B	Total
Net Book Value Balance as at December 31, 2012 per March 13, 2013 Letter to Board	291,922	39,718	331,640
2013 Depreciation Expense	(27,302)	-	(27,302)
2014 Depreciation Expense	(26,312)	-	(26,312)
Net Book Value Balance as at December 31, 2014 per Application	238,308	39,718	278,026

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

(page left blank intentionally)

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?

RESPONSE:

a) Monthly Billing

b) Monthly Billing

c) Billing and collecting expenses increased in 2013 to accommodate the increased effort and resources required as a result of moving to monthly billing and collecting processes. Cost increases included labour, supplies (paper, envelopes, ink etc), postage and handling.

d) As of December 31, 2013 there were 5.75% of customers enrolled on e-billing. This number has increased to 14% as of June 30, 2014.

e) In early 2013 e-billing became available and was promoted via bill insert and on the company website. In early 2014, an e-billing enrollment contest was launched. The program consisted of three months of bill inserts, website updates, notices on envelopes and bills and small monthly prizes were awarded to customers along with a grand prize at the end of the contest. E-billing uptake increased by 150%.

f) In addition to further promotions of e-billing in an effort to reduce the costs of printing, stuffing and mailing bills, the consolidation of some functions have resulted in less staff (ie EBT clerk). Printed reminder notices were discontinued in 2014 and replaced by a lower cost alternative of telephone reminders.

g) Please review responses to 2.0-VECC-3 and 2.0-VECC-5.

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.

RESPONSE:

As described in Section 5.3.1, at page 27 of API's Distribution System Plan (Exhibit 2, Tab 3, Schedule 1, Appendix A), some of the information flows and processes in API's Asset Management Process are currently informal in nature. With respect to asset condition assessment, the results of the inspection and maintenance programs referenced in Section 4 of API's DAMP are considered in the ACA process, however there is no formal compilation of these results into an overall health index or risk distribution that would include specific findings or recommendations for each asset category.

a) As described above, API does not have a formal health index or risk distribution that would include specific findings or recommendations by asset category. API has, however, provided information describing the rationale for the range of lifecycle management practices for each asset category. Section 5.3.3 of API's Distribution System Plan (Exhibit 2, Tab 3, Schedule 1, Appendix A) contains a discussion of "Lifecycle Optimization by Asset Type". This section describes the balance between the inspection and maintenance programs outlined in Section 4 of API's DAMP, and the capital investments for replacement of these assets that are included in the Distribution System Plan. For asset categories that are related to high levels of investment within the plan (e.g. poles and rights of way), this section also describes how the planning and condition assessment methodologies outlined in Sections 5 and 6 of the DAMP have been applied to that asset category to arrive at the proposed capital investment.

b) API has not developed a formal health or risk distribution of its assets. API has however used the results of the third-party pole testing initiated in 2009 to evaluate the risk of failure for its pole assets and in turn has set a replacement target of 500 poles per year. API also uses the results of the pole testing program to prioritize pole replacement within the pole replacement program that comprises the majority of spending in the condition-based replacements (i.e. the System Renewal category). For economic reasons, related assets such as conductor and pole line hardware would typically be replaced in conjunction with these pole replacements and are therefore not evaluated separately from a health or risk distribution perspective. For sustaining replacements of other assets, the driver for replacement is typically the actual failure of the asset, or a high risk of failure identified on a case-by-case basis during the course of regular inspection and maintenance activities.

c) N/A.

d) N/A.

e) No. As described above, API has initiated a relatively straightforward inspection and testing program for its distribution poles, which are related to the bulk of its condition-based investments. Given the drivers identified in part b) above for the condition-based replacement of other assets, API sees little value in the development of a formal asset condition assessment and health/risk distribution.

(page left blank intentionally)

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.

RESPONSE:

a) Project/program impacts on levels of service:

i. Protection, Automation, Reliability –The anticipated projects within this program fall into four general categories, as outlined in the program justification:

   i. Installation of additional SCADA-capable devices, especially on systems with loop configurations (e.g. portions of the East of Sault 34.5 kV)
   ii. Installation of new 3-phase platform transformers on the East of Sault 34.5 kV system to allow for improved contingency response to failure at single-element stations, as well as for station off-loading for maintenance during light loading periods.
   iii. Replacement of main-line fused disconnects with reclosers (prioritize heavily loaded devices).
   iv. Installation of additional fault circuit indicators (FCI's)

Please refer to the "SCADA System Business Case for Algoma Power Inc." provided in response to 4-VECC-20(b) for an analysis of the reliability benefits and the cost/benefit analysis of SCADA-related investments in relation to items i, iii, and iv above.

With respect to item ii above, API expects that installation of three new 3-phase platform transformer banks on the East of Sault 34.5 kV system would provide the ability to off-load any existing single-element transformer and de-energize the associated substation for maintenance purposes. The outage requirements for maintenance of these stations over a six-year maintenance cycle would amount to a total SAIDI impact of approximately 7 hours. This translates into an average expected SAIDI reduction of approximately 1.16 hours per year by proceeding with these projects. These three banks are expected to cost in the range of $400k each. API notes that additional drivers for this particular investment, as well as examples of additional benefits beyond the definite SAIDI impact noted above were provided in the program justification on pages 76-80 in Section 5.4.5.2 of the Distribution System Plan (Exhibit 2, Tab 3, Schedule 1, Appendix A).

ii. ROW Hardening – This program is expected to improve reliability by reducing the frequency of outages caused by fall-in of decadent off-ROW trees. While API's consultant was not able to specifically quantify the reliability improvements resulting from the recommended funding levels for API's overall vegetation management programs, they were able to forecast a 40-60% increase in the frequency of tree-caused outages should the programs not proceed. In terms of cost impacts, the consultant found that based on field conditions at API, any deferral of program funding would compound at a rate of 15.5% per annum. Please refer to Appendices C and E of the Distribution System Plan (Exhibit 2, Tab 3, Schedule 1, Appendix A) for more detail.

iii. Hawk Junction DS, Echo River TS – These projects are driven by reliability, but in the context of contingency performance rather than historical reliability issues. While there are likely to be ancillary reliability benefits as a result of undertaking these projects, specific reliability improvements would be difficult to forecast with any degree of confidence.

iv. All System Access – These programs allow API to continue to meet DSC targets/requirements for levels of service with respect to service connections and upgrades.

v. All System Renewal – The primary driver for these programs is the replacement of end of life assets. Given the levelized, sustaining nature of the investments in this category, the overall impact on levels of service is expected to be relatively neutral.

vi. Business Systems – Approximately $92k of the annual investment is related to establishing communications to field devices for integration to SCADA. Please refer to the "SCADA System Business Case for Algoma Power Inc." provided in response to 4-VECC-20(b) for an analysis of the reliability benefits and the cost/benefit analysis of SCADA-related investments. The remaining annual investment relates to development and integration of other business systems (GIS, OMS, etc.) that are driven by operational efficiencies. This work is expected to have ancillary reliability benefits, however these are difficult to accurately quantify.

vii. IT/Fleet/Facilities/Tools/etc. – The primary driver for these investments is to replace end of life assets in these categories in order to provide the equipment, facilities and tools necessary to support API's day to day business requirements. Given the levelized, sustaining nature of the investments in this category, the overall impact on levels of service is expected to be relatively neutral.

b) The majority of API's maintenance activities related to distribution assets are based on a combination of DSC requirements, manufacturer's recommendations, and good utility practices. Most of these programs have been in place for many years and are expected to continue with a relatively neutral impact on reliability overall. The maintenance programs associated with vegetation management may have long-term positive reliability impacts. While API's consultant was not able to specifically quantify the reliability improvements resulting from the recommended funding levels for API's overall vegetation management programs, they were able to forecast a 40-60% increase in the frequency of tree-caused outages should the programs not proceed. In terms of cost impacts, the consultant found that based on field conditions at API, any deferral of program funding would compound at a rate of 15.5% per annum. Please refer to Appendices C and E of the Distribution System Plan (Exhibit 2, Tab 3, Schedule 1, Appendix A) for more detail. The O&M activities related to SCADA implementation are largely offset by cost savings and are expected to result in annual SAIDI and SAIFI reductions of approximately 1 hour and 1.3 interruptions.

c) Please see the following table. In selecting the projects/programs related to "capital growth" to include on this table, API has included any new projects or programs presented in its Distribution System Plan (i.e. programs that were included in API's previous cost of service application that have continued or transitioned into similar programs with similar levels of investment were not included).

Primary Driver	Capital 2015-2019 ($000)	O&M 2015 ($000)	Activities	Results & Timing	Corresponding Project/Program*
Operational Efficiencies	5,500		Remove backlog of off-ROW hazard trees.	Ongoing improvements in cost effectiveness of vegetation maintenance program. Ongoing reliability improvements.	ROW Hardening
	855		Develop and integrate GIS, OMS, SCADA, etc.	Ongoing improvements in efficiencies of planning, construction and maitenance activities and business processes	Business Systems
Contingency - High Risk	5,547		Substation modifications	Resolve contingency risks by 2015/2017	Hawk Junction DS, Echo River TS
Reliability & Contingency Improvement	2,197		Various (see response to (a) for examples)	Improved reliability - incremental over 5-year plan (see response to (a) for quantification). Improved contingencies. Operational efficiencies (see response to (d) for details.	Protection, Automation, Reliability
		256	Control room operation of API SCADA system		SCADA & Dispatch
Capital, Maintenance Support	450		Create new ROW access	Improved ability (safer and lower cost) to access for maintenance, outage response and construction - incremental improvements on an ongoing basis.	ROW Access
Maintain current service levels (public and employee safety, reliability)		3,426	Maintain VM workload over larger area associated with recently expanded ROW's	Maintain current service levels.	Vegetation Management

***Capital - Corresponding Capital Projects/Programs at Reference 1**
O&M - Corresponding O&M Programs at Exhibit 4/Tab 3/Sch. 1

d) API expects efficiencies in the unit costs associated with its vegetation management program as a result of fewer reactive responses to hazard trees, as well as progress on the most efficient cycle lengths identified for each of the vegetation management activities. API also expects that the annual cost increases associated with SCADA and the use of a control room will be largely offset by changes to business processes and operational activities as described and quantified in Exhibit 4, Tab 1, Schedule 1, Appendix B, p. 11-12.

The 2015-2019 capital costs presented for most programs are level over the 5-year plan and are not adjusted upward for inflation. This is a reflection of the expectation for efficiencies in design and engineering processes as a result of the use of new business systems, as well as efficiencies in the construction process as a result of incorporating the use of the SCADA system for switching and work protection.

e) API intends to report on Distribution System Plan Implementation Progress as required by recent changes to IRR filing requirements, and as otherwise directed by the Board.

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.

RESPONSE:

a) This was confirmed in "Explanatory Notes on Variances" in the above reference where it is stated that "2017 amount is due to Echo River TS upgrade project".

b) Please refer to API's response to 2Staff13 for discussion on pacing consideration and rate impacts. With respect to the Echo River TS upgrade project specifically, alternatives were evaluated that would have paced the investments in a way that would lead to smoother rate impacts. Pages 33-35 of API's Distribution System Plan (Exhibit 2, Tab 3, Schedule 1, Appendix A) provide a detailed description of the significant drawbacks associated with a "paced" distribution solution in comparison to the proposed one-time TS upgrade.

(page left blank intentionally)

13. 2Staff13 – Pacing Considerations and Rate Impact

- RRFE Report[1]
- 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.

RESPONSE:

a) API has presented a Distribution System Plan that is based largely on investments related to sustaining asset replacement and meeting mandated service obligations. Examples of the pacing and rate impacts associated with these investments can be found in the following sections of API's Distribution System Plan (Exhibit 2, Tab 3, Schedule 1, Appendix A):

   i. Section 5.2.1(a) on page 3 describes how levelized annual spending in the System Access, System Renewal and General Plant categories is largely driven by sustaining asset replacement requirements and consideration of historical actual costs of meeting

---

1 http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf

regulatory obligations for customer service work and plant relocation.

ii. Section 5.2.1(b) on page 4 describes the relative cost benefits of a sustaining level of asset replacement on a proactive basis considering both the risk of failure and economics of replacement vs maintenance.

iii. In Section 5.3.1(b), at the bottom of page 27, API describes how projects and programs related to regulatory obligations and sustaining asset replacement are given the highest priorities in the annual budgeting process. API goes on to describe how any projects that are more "discretionary" in nature are evaluated and prioritized in keeping with the "Annual Budgeting Considerations" section of the Asset Management Flowchart on page 26, which includes consideration of rate impacts.

iv. Section 5.3.3, beginning on page 38, provides an introduction on the balance between inspection, maintenance, repair and replacement programs and how each of the sustaining asset replacement programs in the System Renewal category is budgeted. This section goes on to describe how the balance between inspection, maintenance, repair and replacement are optimized for each major asset category.

v. In Part A of the justification for each project/program throughout Section 5.4.5.2, API discusses how most projects and programs have been budgeted and paced to result in levelized annual spending to the extent possible. In consideration of rate impacts, API has also reviewed the feasibility and risks of "do-nothing" alternatives and in changing the annual program targets or spending levels. These considerations are discussed in Part C of the justification for each project/program.

b) Conditions under which the DSP would be modified:

   i. Load Adjustments - If there was significant reduction in load East of Sault Ste. Marie, then API expects that the Echo River TS project proposed in 2017 would be modified, deferred, or cancelled. However, API has no indication of any load reduction as the system reached a higher winter peak load at the beginning of 2014 than in prior years.

   ii. Budgetary Constraints - In the event of budgetary constraints, API would review the capital program as a whole to determine any required modifications, based on the dollar amount of the adjustment required. The qualitative and quantitative impacts of deferring any specific investment are detailed in Part C of the justification for each project/program in Section 5.4.5.2 of the Distribution System Plan at Exhibit 2, Tab 3, Schedule 1, Appendix A.

(page left blank intentionally)

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 1^{st} 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 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 3^{rd} 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

---

RESPONSE:

a) No.

b) The "Consolidated Distribution System Plan Overview" provided at Exhibit 2, Tab 3, Schedule 1 provides an extensive description of API's service territory and distribution system, with a focus on issues and challenges that are unique to API. From this description, it is clear that API does not have a suitable cohort group within the Province of Ontario for the purpose of benchmarking.

c) See answer to b) above.

With respect to IT expenditures, FortisOntario has integrated API with CNPI's IT systems, so that IT services are supplied to API as a shared corporate service. Accordingly, the allocation is not comparable to industry peers or with respect to benchmarking. API does follow best practices as it relates to IT with respect to hardware assets specific to the business requirements of API. A five year lifecycle is utilized to determine workstation and server replacement schedules. This schedule coincides with the maximum warranty available by the vendor and therefore ensures the assets are adequately supported.

d) As described in API's application for smart meter cost recovery in EB-2012-0104, pursuant to O. Reg. 427/06, API and a number of other LDC's "piggybacked" on the London Hydro AMI RFP process. During this process, the vast majority of small to medium sized LDC's (including API) organized into regional groups in order to take advantages of cost savings associated with infrastructure sharing. The process proceeded with the "District 9" group (API combined with a number of other LDC's based in northeastern Ontario) being evaluated as a "virtual utility" in the London evaluation model, and Sensus was ultimately selected as the preferred vendor for this group.

The contract between API and Sensus contract specifies that API owns the infrastructure specific to its service territory (meters and collectors), while Sensus owns and operates the RNI (the head-end server and software required to operate the system as well as collect, store and report on metering data). Sensus is required to operate, maintain (including regular preventive maintenance) and repair (including all parts and labour) the system as required to meet certain service levels. Sensus must also own and operate the RNI in a secure datacenter and operate with full off-site backup for disaster recovery purposes.

With respect to costs relative to other vendors, the specific costs and scopes of work associated with the proposals from various vendors were provided in response to the London Hydro RFP, and were part of the London Hydro vendor selection process.

(page left blank intentionally)

15. 2Staff15 – 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?

RESPONSE:

a) While GLPT has initiated the Regional Infrastructure Plan process, there is no Regional Infrastructure Plan at this time for the East Lake Superior area.

b) To remedy the East of Sault Ste. Marie 34.5 kV System reliability concerns, the Echo River TS upgrade project has been included in API's capital plan for 2017. API is awaiting the outcome of the RIP process to determine the cost implications and cost responsibilities of any projects related to the other reliability concerns.

c) Refer to part b) above. Echo River is in the current five-year plan (2017). Any other projects will depend on the outcome of the Regional Infrastructure Planning process. Should these projects not be part of a formal Regional Infrastructure Plan, then local planning between GLPT and API would proceed in accordance with the provisions of the TSC.

d) API is currently processing a request for a large load addition in this area that would require both distribution and transmission system upgrades. Should this request proceed to connection, API expects to follow the relevant DSC and TSC processes related to economic evaluations and cost recovery for system expansions. API expects that the resulting upgrade costs to be borne by API may trigger one of the ICM's discussed in the evidence.

e) The kickoff meeting was postponed until July 31, 2014. The kickoff meeting provided all participants in the East Lake Superior area (GLPT, API, PUC Distribution Inc., Chapleau PUC, Hydro One, OPA and IESO) with an overview of the process, timelines and next steps. The outcome of this meeting is that GLPT will formally request data from all participants that is required to conduct the Needs Screening portion of the process.

Participants will have 60 days to provide this information and GLPT will then have a further 60 days to complete an analysis to determine whether or not a Regional Infrastructure Plan is required.

f) Public engagement activities have not been planned at this point as there is no certainty as to whether a Regional Infrastructure Plan will be required.

(page left blank intentionally)

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.

RESPONSE:

a) In accordance with the Chapter 5 Filing requirements, those projects that resulted from asset condition assessment are included in the "System Renewal" category, and those projects that resulted from capacity/contingency analysis are included in the "System Service" category. The material projects in each of these categories can be found in the Table of Expenditures by Category referenced in the pre-amble above.

b)

i. Section 6.3.2 of the Transmission System Code provides that "Where a transmitter has to modify a transmitter-owned connection facility to meet a load customers need, the transmitter shall require the load customer to make a capital contribution to cover the cost of the modification…"

ii. The amount considers that API is responsible for 100% of the costs of this project – please refer to i. above.

iii. There are no updates since the submission of the application.

c)

i. No. 4 Circuit – The likelihood of API bringing an ICM is entirely dependent on whether a potential new load customer decides to proceed with their project. The cost implications will result from the economic evaluations performed in accordance with the relevant DSC and TSC processes.

ii. Goulais/Batchawana – Both the likelihood and cost implications will depend on the outcome of the Regional Infrastructure Planning process.

d) The table provided at that reference is a “Table of Capital Expenditures by Category” and does not include any inspection and maintenance programs.

e) Please refer to Appendix 2-AB, provided at Exhibit 2, Tab 3, Schedule 1, Appendix D.

f) For major capital expenditures, please refer to Appendix 2-AB, provided at Exhibit 2, Tab 3, Schedule 1, Appendix D. The table in this Appendix provides trends over time for all major capital expenditures, broken down by category, as well as explanations of any trends or outliers in capital expenditures.

For capital vs. O&M (planned vs. unplanned), please refer to the table below. Note that outage restoration costs are the only “unplanned” costs that are tracked to sufficient level of detail that allows an accurate breakout from “planned” costs.

The table below assumes O&M increases by 2% per annum after 2015.

(Amounts in $000)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Total Capital Expenditure	10,460	9,785	10,043	11,290	7,883	8,875	8,971	13,371	8,321	7,321
Total System O&M	5,732	7,367	7,266	7,517	7,903	9,136	9,319	9,505	9,695	9,889
"Planned" O&M	4,958	6,453	6,695	6,761	7,374	8,355	8,522	8,692	8,866	9,044
"Unplanned" O&M	774	914	571	756	529	781	797	813	829	845

For capital vs. depreciation, please refer to the following table.

(Amounts in $000)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Total Capital Expenditure	10,460	9,785	10,043	11,290	7,883	8,875	8,971	13,371	8,321	7,321
Depreciation	3,927	4,244	4,406	4,248	3,457	3,597	4,000	4,300	4,600	4,800

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.

RESPONSE:

a + b) The information being requested in this question is at the core of the Chapter 5 Filing Requirements and has been provided in API's Distribution System Plan at Exhibit 2, Tab 3, Schedule 1, Appendix A. The information provided below provides numerous references to the specific sections of the Distribution System Plan in which this information can be found.

a) <u>Discretionary vs non-discretionary nature of project/program</u> – Section 5.4.1(c) describes discretionary vs non-discretionary nature of material projects and programs within each of the Chapter 5 categories.

<u>a) b) i Overview of project/program economics, discussion of alternatives, etc.</u> – Part C of the justification for each material project/program provides information of the economic considerations of alternative and/or do-nothing approaches where applicable.

<u>a) ii Additional documentation such as independent studies that support a recommended option</u> – Appendix E of the Distribution System Plan provides a third-party review and quantification of vegetation management work, risks and resource requirements. In addition, the "SCADA System Business Case for Algoma Power Inc." provided in response to 4-VECC-20(b) provides an analysis of the reliability benefits and the cost/benefit analysis of SCADA-related investments as well as a recommended implementation strategy.

<u>a)</u> <u>iii b) ii Impact of projects/programs on rates</u> – Due to the nature of rate-setting for API, the rates charged to the majority of customers will not be directly

impacted by individual programs and projects. The Residential – R1 and Residential – R2 customer classes have their rates set by regulation.

However it is possible to examine the impact on the test year revenue requirement. Based on the parameters presented in this Application, a capital addition of $100,000 in the test year will result in an approximate increase of $3,500 to the overall revenue requirement. On this basis it is possible to extrapolate the following impacts to revenue requirement. In general these are:

Investment Category	Project/Program Description	2015 $,000	Impact on Revenue requirement $
System Access	Customer Demand Work (New Connections and Service Upgrades)	$907	$ 32,400
	Total of Items Less Than Materiality (New Transformers/Meters, Plant Relocations)	$113	$ 4,000
System Renewal	Replacements due to Storm Damage	$102	$ 3,600
	Small Priority Replacements - Lines/Stations (One-off Priority Replacements)	$198	$ 7,100
	Express Feeder Rebuilds (Part of Pole Replacement Program)	$977	$ 34,900
	Line Rebuilds (Part of Pole Replacement Program)	$2,633	$ 94,100
	Total of Items Less Than Materiality (EOL Transformers, Recloser Replacement)	$134	$ 4,800
System Service	Protection, Automation, Reliability (Substations, Express Feeders, Lines)	$197	$ 7,000
	Hawk Junction DS Rebuild/Expansion	$997	$ 35,600
	Echo River TS - Add Second Transformer		$ -
	Total of Items Less Than Materiality (Transformers for Volt Conv & Capacity Issues)	$38	$ 1,400
General Plant	ROW Access Program	$90	$ 3,200
	IT Hardware	$170	$ 6,100
	Business Systems (SCADA, GIS, OMS, etc.)	$171	$ 6,100
	Fleet (1 aerial device, 4 pickups, misc trailers, ORV's, snowmobiles)	$551	$ 19,700
	ROW Hardening Program	$1,500	$ 53,600
	Total of Items Less Than Materiality (Facilities, Tools, Software, Land Rights)	$197	$ 7,000

a)iv b) iii Pacing considerations – Beginning at the last paragraph on page 27 in Section 5.3.1, API describes the project/program prioritization and budgeting approaches taken to allow for paced and sustainable programs that levelize spending by asset type to the extent possible and results in the efficient use of internal resources. In addition, Section 5.3.3(a) describes the lifecycle optimization strategies by asset type that are factored into the budgeting of replacement programs. Finally, Part C of the justification for each program in 5.4.5.2 describes implication of deviating from planned targets for sustainment programs or deviating from historical actual spending for other items.

a) v b) iv Benefits to be incurred – Part B of the justification for each project/program in Section 5.4.5.2 outlines provide information on benefits expected in relation to the project/program. In addition, the risks associated with do-nothing options or alternatives are provided in Part C, where applicable. Given the non-discretionary nature and/or sustaining replacement nature of the majority of API's proposed projects and programs, many of these benefits are qualitative rather than quantitative. Quantitative benefits are provided in the independent studies related to some of the more "discretionary" projects, referenced above.

(page left blank intentionally)

2-Energy Probe-3

Ref: Exhibit 2, Tab 1, Schedule 2

Please add two columns to the Rate Base Variance Table to include 2010 actuals and the 2010 forecast used in the last cost of service rebasing application.

RESPONSE:

Please see response on next page.

RATE BASE VARIANCES

Description	2010 Test Year	2010 Actual	2011 Board Approved	2011 Actual	Variance from 2011 Board Approved	2012 Actual	Variance from 2011 Actual	2013 Actual	Variance from 2012 Actual	2014 Bridge Year	Variance from 2013 Actual	2015 Test Year	Variance from 2014 Bridge
Gross Fixed Assets	117,773,796	116,241,613	130,630,310	125,832,717	(4,797,593)	138,645,014	12,812,297	148,346,334	9,701,320	157,557,032	9,210,698	165,812,251	8,255,219
Accumulated Depreciation	(48,538,274)	(48,181,771)	(54,436,624)	(52,173,141)	2,263,483	(57,761,045)	(5,587,904)	(61,515,630)	(3,754,585)	(65,418,323)	(3,902,694)	(68,713,111)	(3,294,788)
Net Book Value	69,235,523	68,059,841	76,193,686	73,659,576	(2,534,110)	80,883,969	7,224,393	86,830,705	5,946,736	92,138,709	5,308,004	97,099,140	4,960,431
Average Net book Value	65,578,302	64,990,462	72,711,604	70,859,709	(1,851,895)	77,271,772	6,412,064	83,857,337	6,585,564	89,484,707	5,627,370	94,618,924	5,134,218
Working Capital Requirement	25,955,625	25,816,880	27,437,586	26,758,087	(679,498)	26,928,370	170,283	30,688,399	3,760,028	34,253,251	3,564,852	35,750,569	1,497,318
Working Capital Allowance	3,893,344	3,872,532	4,115,638	4,013,713	(101,925)	4,039,256	25,542	4,603,260	564,004	5,137,988	534,728	4,647,574	(490,414)
Rate Base	**69,471,646**	**68,862,994**	**76,827,242**	**74,873,422**	**(1,953,820)**	**81,311,028**	**6,437,606**	**88,460,596**	**7,149,569**	**94,622,694**	**6,162,098**	**99,266,498**	**4,643,804**

<u>2-Energy Probe-4</u>

Ref: Exhibit 2, Tab 1, Schedule 3

a) Are the fixed asset continuity schedules for 2011 and 2012 based on CGAAP or ASPE?

b) Please confirm that the 2013 through 2015 figures are based on ASPE.

c) If the response to part (a) is CGAAP, please indicate the impact on the cost of fixed assets closed to rate base under ASPE instead of CGAAP for both 2011 and 2012.

d) Please explain what the "allocations" column in each of the continuity schedules represents and please show the calculation of these amounts in each of the years shown.

RESPONSE:

a) The fixed asset continuity schedules for 2011 and 2012 are based on ASPE.

b) The 2013 through 2015 figures are based on ASPE.

c) N/A

d) The allocations represent the corporate allocation of assets to API. See Exhibit 4 for the discussion of shared services and corporate allocations.

The calculations are as follows.

CNPI Corporate End of Year Balances

	2011 - 1% *				
	COST			ACCUM DEPR	
	EOY	ALLOCATION	CHANGE NBV	EOY	ALLOCATION
Computer Hardware	2,564,525.81	25,645.26	9,469.25	(1,617,601.05)	(16,176.01)
Computer Software	7,457,958.23	66,548.20	28,286.21	(4,549,850.03)	(38,261.99)
TOTAL	**10,022,484.04**	**92,193.46**	**37,755.46**	**(6,167,451.08)**	**(54,438.00)**
Depreciation Expense					**54,438.00**

	2012 - 32.1% *				
	COST			ACCUM DEPR	
	EOY	ALLOCATION	CHANGE NBV	EOY	ALLOCATION
Computer Hardware	3,126,376.53	1,003,566.87	366,393.04	(1,955,465.98)	(627,704.58)
Computer Software	7,902,394.24	2,278,861.25	892,838.53	(5,032,846.76)	(1,357,736.51)
TOTAL	**11,028,770.77**	**3,282,428.12**	**1,259,231.57**	**(6,988,312.74)**	**(1,985,441.09)**
Depreciation Expense					**263,497.00**

	2013 - 32.1% *				
	COST			ACCUM DEPR	
	EOY	ALLOCATION	CHANGE NBV	EOY	ALLOCATION
Computer Hardware	3,318,075.72	1,065,102.31	(70,639.21)	(2,367,225.00)	(759,879.23)
Computer Software	9,442,512.41	2,773,239.19	308,273.32	(5,612,611.92)	(1,543,841.13)
TOTAL	**12,760,588.13**	**3,838,341.49**	**237,634.11**	**(7,979,836.92)**	**(2,303,720.35)**
Depreciation Expense					**318,279.26**

	2014 - 33.5% *				
	COST			ACCUM DEPR	
	EOY	ALLOCATION	CHANGE NBV	EOY	ALLOCATION
Computer Hardware	3,807,075.72	1,275,370.37	35,166.32	(2,790,987.95)	(934,980.96)
Computer Software	9,926,512.41	3,056,330.43	12,289.48	(6,219,982.46)	(1,814,642.89)
TOTAL	**13,733,588.13**	**4,331,700.79**	**47,455.80**	**(9,010,970.41)**	**(2,749,623.86)**
Depreciation Expense					**445,903.50**

	2015 - 33.5% *				
	COST			ACCUM DEPR	
	EOY	ALLOCATION	CHANGE NBV	EOY	ALLOCATION
Computer Hardware	4,171,075.72	1,397,310.37	(16,946.21)	(3,205,573.66)	(1,073,867.18)
Computer Software	10,367,512.41	3,204,065.43	(63,664.78)	(6,851,026.59)	(2,026,042.68)
TOTAL	**14,538,588.13**	**4,601,375.79**	**(80,611.00)**	**(10,056,600.25)**	**(3,099,909.85)**
Depreciation Expense					**350,286.00**

* Percentage of corporate computer hardware and software allocated to API.
Increased shared services in 2012 including the corporate SAP system.

<u>2-Energy Probe-5</u>

Ref: Exhibit 2, Tab 1, Schedule 4

a) **Please provide a table at the same level of detail that shows the 2010 actual gross fixed assets compared to the forecasted levels for the 2010 bridge year in the last cost of service application.**

b) **Actual gross assets in 2011 were approximately $4.8 million below the 2011 Board Approved figure. Please provide an explanation for the reduction in the following categories:**

i) computer equipment and software (accounts 19209, 1925 and 1611) - reduction of about $3.0 million;
ii) land (account 1805) - reduction of $322,000;
iii) building and fixtures (account 1808) - reduction of $307,000; and
iv) other tangible property (account 1990) - reduction of $2.15 million.

RESPONSE:

Please see response on next page.

a) Gross fixed assets with 2010 added.

OEB Account	Description	2010 Test	2010 Actual	2011 Board Approved	2011 Actual	Variance from 2011 Board Approved	2012 Actual	Variance from 2011 Actual	2013 Actual	Variance from 2012 Actual	2014 Bridge Year	Variance from 2013 Actual	2015 Test Year	Variance from 2014 Bridge
	GROSS ASSETS													
	Intangible Plant													
1608	Franchises & Consents	-	-	-	-	-	-	-	-	-	-	-	-	-
1611	Computer Software	-	69,441		901,465	901,465	3,796,360	2,894,895	5,197,714	1,401,354	5,824,025	626,311	6,068,315	244,290
1612	Land Rights	-	17,049,759		19,183,404	19,183,404	19,982,353	798,949	20,332,642	350,289	20,537,569	204,927	20,691,054	153,486
	Sub Total - Intangible Plant	**-**	**17,119,200**	**-**	**20,084,869**	**20,084,869**	**23,778,713**	**3,693,844**	**25,530,356**	**1,751,643**	**26,361,594**	**831,238**	**26,759,369**	**397,775**
	Land and Buildings													
1805	Land	853,958	537,175	908,331	586,257	(322,074)	530,925	(55,332)	568,413	37,489	568,413	-	568,413	-
1806	Land Rights	16,966,966	-	19,184,594	-	(19,184,594)	-	-	-	-	-	-	-	-
1808	Buildings and Fixtures	838,778	575,618	860,528	552,917	(307,611)	826,223	273,306	1,043,647	217,424	1,657,647	614,000	1,681,503	23,855
	Sub Total - Land and Buildings	**18,659,702**	**1,112,792**	**20,953,453**	**1,139,174**	**(19,814,280)**	**1,357,147**	**217,974**	**1,612,061**	**254,913**	**2,226,061**	**614,000**	**2,249,916**	**23,855**
	DS													
1820	Distribution Station Equipment - Normally Primary below 50	11,414,798	10,862,091	11,508,140	11,009,743	(498,397)	11,171,349	161,607	11,044,910	(126,439)	11,857,863	812,953	13,017,682	1,159,820
	Sub Total - DS	**11,414,798**	**10,862,091**	**11,508,140**	**11,009,743**	**(498,397)**	**11,171,349**	**161,607**	**11,044,910**	**(126,439)**	**11,857,863**	**812,953**	**13,017,682**	**1,159,820**
	Poles and Wires													
1830	Poles, Towers and Fixtures	40,811,076	43,570,987	44,695,711	47,659,995	2,964,284	51,213,496	3,553,501	52,825,815	1,612,319	56,137,094	3,311,279	59,331,812	3,194,718
1835	Overhead Conductors and Devices	18,797,810	18,156,128	20,108,465	19,374,573	(733,892)	22,996,518	3,621,945	24,641,995	1,645,477	26,894,663	2,252,668	30,109,207	3,214,544
1845	Underground Conductors and Devices	971,137	993,535	1,066,834	995,549	(71,285)	1,202,216	206,667	1,416,430	214,214	1,416,430	-	1,416,430	-
	Sub Total - Poles and Wires	**60,580,023**	**62,720,650**	**65,871,011**	**68,030,117**	**2,159,106**	**75,412,230**	**7,382,112**	**78,884,240**	**3,472,011**	**84,448,187**	**5,563,947**	**90,857,449**	**6,409,262**
	Line Transformers													
1850	Line Transformers	10,705,102	10,226,674	11,332,715	10,607,830	(724,884)	10,991,941	384,111	11,312,181	320,240	11,789,682	477,500	12,052,328	262,647
	Sub Total - Line Transformers	**10,705,102**	**10,226,674**	**11,332,715**	**10,607,830**	**(724,884)**	**10,991,941**	**384,111**	**11,312,181**	**320,240**	**11,789,682**	**477,500**	**12,052,328**	**262,647**
	Services and Meters													
1855	Services	3,462,040	3,244,616	3,805,879	3,350,146	(455,733)	3,361,906	11,760	3,361,906	-	3,361,906	-	3,361,906	-
1860	Meters	2,179,006	2,065,817	2,206,193	2,139,713	(66,480)	2,208,557	68,844	5,774,705	3,566,148	5,818,852	44,147	4,960,198	(858,654)
1865	Other Install on Cust Prem	-	-		-	-	-	-	194,063	194,063	194,063	-	194,063	-
	Sub Total - Services and Meters	**5,641,046**	**5,310,433**	**6,012,072**	**5,489,859**	**(522,213)**	**5,570,463**	**80,604**	**9,330,674**	**3,760,211**	**9,374,821**	**44,147**	**8,516,167**	**(858,654)**
	General Plant													
1908	Buildings and Fixtures	215,137	258,535	215,137	272,073	56,936	-	(272,073)	-	-	-	-	-	-
1910	Leasehold Improvements	-	-	-	-	-	-	-	43,398	43,398	45,398	2,000	48,806	3,408
	Sub Total - General Plant	**215,137**	**258,535**	**215,137**	**272,073**	**56,936**	**-**	**(272,073)**	**43,398**	**43,398**	**45,398**	**2,000**	**48,806**	**3,408**
	Equipment													
1915	Office Furniture and Equipment	787,880	1,381,921	815,067	1,369,036	553,969	1,422,618	53,582	1,437,049	14,431	1,437,049	-	1,447,741	10,691
1930	Transportation Equipment	4,284,906	4,255,130	4,910,203	4,605,613	(304,590)	4,257,669	(347,945)	4,443,193	185,525	4,994,543	551,350	5,545,085	550,542
1935	Stores Equipupiment								-	-	4,000	4,000	10,816	6,816
1940	Tools, Shop and Garage Equipment	1,558,996	1,553,373	1,613,370	1,621,706	8,336	1,680,526	58,820	1,826,753	146,226	1,901,753	75,000	1,999,113	97,360
1945	Measurement and Testing Equipment	109,423	109,423	109,423	109,423	-	156,816	47,393	208,471	51,655	208,471	-	208,471	-
1955	Communication Equipment	453,917	398,868	453,917	390,852	(63,065)	734,867	344,015	456,212	(278,655)	464,625	8,413	464,625	-
1960	Miscellaneous Equipment	122,557	588,305	122,557	588,305	465,748	588,305	-	588,305	-	588,305	-	588,305	-
1980	System Supv Equip	-	-	-	-	-	5,012	5,012	5,012	-	5,012	-	5,012	-
	Sub Total - Equipment	**7,317,679**	**8,287,020**	**8,024,537**	**8,684,936**	**660,399**	**8,845,813**	**160,877**	**8,964,996**	**119,183**	**9,603,758**	**638,763**	**10,269,167**	**665,409**
	IT Assets													
1920	Computer Equipment - Hardware	988,593	418,996	1,977,412	623,687	(1,353,725)	1,724,797	1,101,109	2,038,646	313,850	2,355,796	317,150	2,647,494	291,698
1925	Computer Software	100,721	-	2,584,838	-	(2,584,838)	-	-	-	-	-	-	-	-
	Sub Total - IT Assets	**1,089,314**	**418,996**	**4,562,250**	**623,687**	**(3,938,563)**	**1,724,797**	**1,101,109**	**2,038,646**	**313,850**	**2,355,796**	**317,150**	**2,647,494**	**291,698**
	Other Distribution Assets													
1875	Other Tangible Assets	2,150,996	16,523		16,523	16,523	16,523	-	16,523	-	16,523	-	16,523	-
1990	Other Tangible Property	-	-	2,150,996	-	(2,150,996)		-		-		-		-
	Sub Total - Other Distribution Assets	**2,150,996**	**16,523**	**2,150,996**	**16,523**	**(2,134,473)**	**16,523**	**-**	**16,523**	**-**	**16,523**	**-**	**16,523**	**-**
	Contributions and Grants													
1995	Contributions and Grants - Credit	-	(91,299)	-	(126,093)	(126,093)	(223,961)	(97,868)	(431,651)	(207,690)	(522,651)	(91,000)	(622,651)	(100,000)
	Sub Total - Contributions and Grants	**-**	**(91,299)**	**-**	**(126,093)**	**(126,093)**	**(223,961)**	**(97,868)**	**(431,651)**	**(207,690)**	**(522,651)**	**(91,000)**	**(622,651)**	**(100,000)**
	GROSS ASSETS TOTAL	**117,773,797**	**116,241,613**	**130,630,310**	**125,832,717**	**(4,797,593)**	**138,645,014**	**12,812,297**	**148,346,334**	**9,701,320**	**157,557,032**	**9,210,698**	**165,812,251**	**8,255,219**

b)

i) The reduction in computer hardware and software is a result of a timing difference between when the SAP implementation was planned, in 2011, and when it was actually completed, in 2012.

OEB Account	Description	2011 Board Approved	2011 Actual	Variance from 2011 Board Approved	2012 Actual	Variance from 2011 Actual
1611	Computer Software		901,465	901,465	3,796,360	2,894,895
1920	Computer Equipment - Hardware	1,977,412	623,687	(1,353,725)	1,724,797	1,101,109
1925	Computer Software	2,584,838	-	(2,584,838)	-	-
	Total Computer Hardware and Software	4,562,250	1,525,152	(3,037,098)	5,521,157	3,996,004

ii) The reduction in the land account 1805 is a result of the SAP implementation and a review of the mapping of general ledger accounts to OEB accounts. An amount of $316,783 was reallocated to land rights, account 1612.

iii) The reduction in building and fixtures is a result of a timing difference between 2011 and 2012.

OEB Account	Description	2011 Board Approved	2011 Actual	Variance from 2011 Board Approved	2012 Actual	Variance from 2011 Actual
1808	Buildings and Fixtures	860,528	552,917	(307,611)	826,223	273,306

iv) The reduction in other tangible property, account 1990, is a result of the SAP implementation and a review of the mapping of general ledger accounts to OEB accounts. The amounts in account 1990 were reallocated, $1,872,250 to poles, towers and fixtures, account 1830 and $278,746 to miscellaneous equipment, account 1960.

(page left blank intentionally)

<u>2-Energy Probe-6</u>

Ref: Exhibit 2, Tab 1, Schedule 5

a) What is the billing frequency for each of API's rate classes?

b) Has this billing frequency changed since API's last cost of service proceeding that set 2011 rates? If yes, please explain what changes were made and when they were made.

RESPONSE:

a) API is billing all of its customers on a monthly basis as of November, 2012.

b) Prior to November 2012, customers were billed on the following frequency:

   a. Residential – bimonthly
   b. Small commercial – bimonthly
   c. Large commercial – monthly
   d. Seasonal – annually

(page left blank intentionally)

2-Energy Probe-7

Ref: Exhibit 2, Tab 1, Schedule 5

a) **Please provide the calculations used to derive the current RPP and non-RPP commodity estimates of $0.08899/kWh and $0.08949/kWh figures.**

b) **Please update the RPP and non-RPP prices based on the latest Regulated Price Plan Report. In doing so, please provide the calculations used to derive the new rates.**

c) **Please provide the impact of the updated RPP and non-RPP prices used in part (b) on each of the working capital allowance component of rate base and the revenue deficiency for the test year.**

RESPONSE:

a) API used the Regulated Price Plan Report November 1, 2013 to October 31, 2014, dated October 17, 2013. The following data was used to derive the cost of power:

Forecast Price
Regulated Price Plan - Price Report
Nov. 1, 2013 to Oct. 31, 2014

	RPP Consumer	Non-RPP Consumer
Load-Weighted Price for RPP Consumers ($/kwh)	0.02156	0.02156
Impact of Global Adjustment ($/kWh)	0.06793	0.06793
Othe Adjustments ($/kWh)	-0.0005	0
Energy Costs ($/kWh)	0.08899	0.08949

b) Updated cost of power derivations are shown below:

Forecast Price
Regulated Price Plan - Price Report
May 1, 2014 to Apr. 30, 2015

	RPP Consumer	Non-RPP Consumer
Load-Weighted Price for RPP Consumers ($/kwh)	0.0287	0.0287
Impact of Global Adjustment ($/kWh)	0.06468	0.06468
Othe Adjustments ($/kWh)	-0.00087	0
Energy Costs ($/kWh)	0.09251	0.09338

c) Updating RPP and non-RPP prices are normally a requirement of the Draft Rate Order and given that a more current version of the Regulated Price Plan Report will be available in the third quarter for use in the Draft Rate Order this step will have to be performed again in the Draft Rate Order.

The first table shows the cost of power components used in the Application.

2015 Cost of Power Expense Summary		
Charge Type	Amount	
4705 - Cost of Power	$	19,132,846
4708 - Charges - WMS	$	943,800
4714 - Charges - NW	$	1,441,452
4716 - Charges - CN	$	1,030,661
4730 - Charges - Rural Rate Assistance	$	278,850
4751 - Charges - IESO SME	$	110,281
Total	$	22,937,890

The second table shows the same cost of power components determined using the Regulated Price Plan Report for May 1, 2014 to April 30, 2015.

2015 Cost of Power Expense Summary		
Charge Type	Amount	
4705 - Cost of Power	$	19,920,815
4708 - Charges - WMS	$	943,800
4714 - Charges - NW	$	1,441,452
4716 - Charges - CN	$	1,030,661
4730 - Charges - Rural Rate Assistance	$	278,850
4751 - Charges - IESO SME	$	110,281
Total	$	23,725,859

2-Energy Probe-8

**Ref: Exhibit 2, Tab 1, Schedule 2 &
Exhibit 2, Tab 1, Schedule 3 &
Exhibit 2, Tab 2, Schedule 1**

Table 2.2.1.1 in Exhibit 2, Tab 2, Schedule 1 reflects the amounts associated with the stranded meters in gross assets and accumulated depreciation.

a) Please confirm that the 2014 amounts are shown as disposals in the 2015 continuity schedule in Exhibit 2, Tab 1, Schedule 3 (page 5).

b) Please confirm that the rate base variance account table in Exhibit 2, Tab 1, Schedule 2 reflects an average net book value for 2015 based on the ending balances of 2014 and 2015.

c) Please confirm that the 2014 year end figure includes stranded meters.

d) Please re-calculation rate base for 2015 based on the average of the opening and closing net book value for 2015, with the opening balance excluding stranded meters.

RESPONSE:

a) The amounts shown as disposals in the 2015 continuity schedule are the opening 2015 stranded meter amounts.

b) The rate base variance account table in Exhibit 2, Tab 1, Schedule 2 reflects an average net book value for 2015 based on the ending balances of 2014 and 2015.

c) The 2014 year end figure includes stranded meters.

d) The following is the recalculation.

Description	2014 Bridge Year	Stranded Meters	2014 Bridge Year Revised	2015 Test Year
Gross Fixed Assets	157,557,032	(890,528)	156,666,504	165,812,251
Accumulated Depreciation	(65,418,323)	652,221	(64,766,102)	(68,713,111)
Net Book Value	92,138,709	(238,307)	91,900,402	97,099,140
Average Net book Value				94,499,771
Working Capital Requirement				35,750,569
Working Capital Allowance				4,647,574
Rate Base				**99,147,345**

2-Energy Probe-9

Ref: Exhibit 2, Tab 2, Schedule 1

a) Please explain why depreciation was not continued to be calculated on the conventional meters noted under Scenario B.

b) Please confirm that the conventional meters in inventory were not included in rate base as part of the 2011 rebasing application and that there was no return on capital or depreciation included in the 2011 approved revenue requirement. If this cannot be confirmed, please explain.

RESPONSE:

a) The depreciation was not continued to be calculated under Scenario B as the conventional meters were treated the same as other assets that are disposed; they were removed from distribution assets within the accounting system and depreciation expense ceased to be calculated for financial and regulatory reporting purposes.

b) The conventional meters in inventory were not included in rate base as part of the 2011 rebasing application and there was no return on capital or depreciation included in the 2011 approved revenue requirement.

(page left blank intentionally)

2-Energy Probe-10

Ref: Exhibit 2, Tab 2, Schedule 1

a) Did API track the net book value of the stranded meters by rate class (i.e. Residential-R1 and Seasonal) on an historical basis? If yes, please provide the net book value for the two categories using this allocation rather than that proposed by API in Table 2.2.1.3.

b) If API does not have the historical information requested in part (a) above, please provide the values of the meters allocated to these two rate classes based on the cost allocation model used in the 2011 rebasing application.

c) Based on the responses provided above, please provide revised versions of Table 2.2.1.3 that use the different allocation factor to calculate the rate rider for both rate classes.

RESPONSE:

a) API did not track the net book value of the stranded meters by rate class.

b) Based on the cost allocation model used in the 2011 rebasing application, a value of $1,343,673 was allocated to the Residential R1 rate class and $608,701 was allocated to the Seasonal rate class.

c) REVISED Table 2 2 .2.1.3: Calculation of Stranded Meter Rate Rider

	Total	Residential - R1	Seasonal
Value of Meters Allocated per 2011 Rebase Application	1,952,374	1,343,673	608,701
% Allocation Based on Value of Meters		68.8%	31.2%
Stranded Meter Costs			
Scenario A	$ 238,308		
Scenario B	$ 39,718		
	$ 278,026	**$ 191,345**	**$ 86,682**
Average Metered Customers for 2015 Test Year		8,496	3,138
Recovery Period in Months		12	12
Stranded Meter Disposition Rate Rider		**$ 1.88**	**$ 2.30**

Note:
Number of meters installed taken from Schedule 2 of Schedule B within API's 2013 IRM EB-2012-0104 submitted October 22, 2012.

2-Energy Probe-11

Ref: Exhibit 2, Tab 3, Schedule 2

Please update the table on page 6 to reflect the most recent actual capital expenditures for 2014 along with the forecast for the remainder of the year.

RESPONSE:

Please see table below.

Investment Category	Category Average 2012-2014	Project/Program Description	Expenditures ($) 2012 (Actual)	2013 (Actual)	2014 (to June 30)	2014 (Forecast)
System Access		Customer Demand Work (New Connections and Service Upgrades)	948,026	833,651	338,952	912,104
		Transformers	100,789	116,907	15,638	76,800
		Total of Items Less Than Materiality (New Meters, Smart Meter add'l Repeaters)	73,191	36,760	3,519	44,147
		Smart Meter Costs		4,454,152	0	
	$1,988,659	**System Access Total**	**1,122,006**	**5,441,470**	**358,109**	**1,033,051**
System Renewal		Replacements due to Storm Damage	71,042	50,919	31,022	94,162
		Small Priority Replacements - Lines/Stations (One-off Priority Replacements)	281,426	239,279	185,879	360,686
		Wawa #2 DS - Replace Circuit Switchers and Switches	122,768	40,945	0	
		Conductor Replacement	3,172,733	1,566,869	0	
		Express Feeder Rebuilds (Part of Pole Replacement Program)		400,288	375,428	1,282,435
		Line Rebuilds (Part of Pole Replacement Program)	1,156,642	415,684	960,345	2,307,279
		Total of Items Less Than Materiality (EOL Transformers, Recloser Replacement)	66,231	57,861	100	126,907
	$3,341,732	**System Renewal Total**	**4,870,842**	**2,771,845**	**1,552,774**	**4,171,469**
System Service		Protection, Automation, Reliability (Substations, Express Feeders, Lines)	505,345	222,365	521,864	557,623
		Hawk Junction DS Rebuild/Expansion			129,005	729,131
		Echo River TS - Add Second Transformer			0	
		Voltage Conversion	85,471	18,538	0	
		Transformers for Voltage Conversion Work & Capacity Issues (Starting 2014 for Ch5 Reqmts)			0	38,400
	$701,935	**System Service Total**	**590,816**	**240,903**	**650,869**	**1,325,154**
General Plant		IT Hardware	332,133	81,638	12,840	105,798
		IT Software	509,804	4,399	0	16,175
		ROW Expansion Program	450,696	277,344	138,375	426,441
		Vegetation Management System			149,002	232,760
		Tools	84,827	191,522	44,423	75,000
		Fleet	113,050	411,264	80,887	551,350
		Service Centres		306,941	30,962	600,000
		Wholesale Meter Communication		118,479	0	
		SCADA		184,750	45,506	119,655
		Total of Items Less Than Materiality	216,172	156,612	47,713	151,488
	$1,567,002	**General Plant Total**	**1,706,682**	**1,732,949**	**549,708**	**2,278,667**
Total	**$7,599,328**		**8,290,346**	**10,187,166**	**3,111,460**	**8,808,341**

2.0-VECC-3

Reference: E2/T1/S5/pg.1

a) Does API monthly or bi-monthly bill its customers? If the former has API reviewed the result of lead/lag studies undertaken by Utilities in Ontario that do monthly billing?

RESPONSE:

a) API bills all customers on a monthly basis. API has not reviewed the result of lead/lag studies undertaken by other utilities. The Company has relied upon the *Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications* dated July 17, 2013 in preparing this application and used the "13% allowance approach."

(page left blank intentionally)

2.0-VECC-4

Reference: E2/T2/S1

a) Please explain why it is appropriate to recover the undepreciated value of the net book value of the conventional meters that were disposed of in 2009.
b) What was the value of conventional meters in storage in 2009 and what was the salvage revenue from these meters?
c) Please confirm that API did not install smart meters in any classes other than residential R1 and Seasonal.

RESPONSE:

a) Please refer to response provided in 2-Energy Probe 9 part b). As outlined in that response, the conventional meters disposed in 2009 were not included in rate base as part of the 2011 rebasing application. Therefore, it is appropriate to recover the undepreciated value of the net book value of the conventional meters that were disposed of in 2009.

b) Please refer to Table 2.2.1.2 in Exhibit 2, Tab 2, Schedule 1 of the Application for a calculation of the residual net book value total of $39,718 for conventional meters in storage that were disposed of. The salvage revenue received from the disposition of these meters was negligible.

c) API did install smart meters in the Residential R2 class. However, those capital costs were not requested as part of the EB-2012-0104 proceeding. Also, the stranded meter values requested for disposition within this Application do not include the value of the meters that were replaced in the Residential R2 rate class.

(page left blank intentionally)

2.0–VECC-5

Reference: 2/T1/S5/pg.1

a) Does API monthly or bi-monthly bill its customers? If the former has API reviewed the result of lead/lag studies undertaken by Utilities in Ontario that do monthly billing?

RESPONSE:

a) API bills all customers on a monthly basis. API has not reviewed the result of lead/lag studies undertaken by other utilities. The Company has relied upon the *Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications* dated July 17, 2013 in preparing this application and used the "13% allowance approach."

(page left blank intentionally)

2.0-VECC-6

Reference: 2/T3/S1/pg.6

a) API explains that since its acquisition by CN Rail, API has been unable to obtain access to service corridors on the former ACR line. What is the incremental cost that API forecasts for this change? What steps has API taken to get approval to use the corridor and what is API's understanding of the impediment to getting access approval.
b) API explains that in 1997 20 year agreements replaced the general right-of-way agreements with ACR. Are these agreements up for renewal in 2017? What are the current annual costs of the agreements?

RESPONSE:

a) For clarification, the issue is not with access to the corridor (rail right of way), but rather with obtaining rail access to locations along the corridor. API can access portions of the corridor at certain locations, but many points along the corridor are then accessible by rail only due to the ruggedness of the terrain (the rail line was blasted through rock or constructed across swamps in many locations). Prior access to hi-rail service through ACR was informal in nature; however ACR had always provided this access within a reasonable time when requested. After several occasions in which API was unable to obtain similar access with CN, API approached CN to negotiate a hi-rail access agreement. API was informed that CN is not willing to provide this service, even on a case-by-case basis. API currently accesses these areas by helicopter for required patrols and would also use helicopters for emergency access. Given that access has been by helicopter only in recent years, API has not included a specific incremental O&M cost for this item in this application. Historical costs for this item were not tracked separately from other inspection and outage response costs. From a long-term perspective, a portion of the capital program for ROW Access Trails will be related to accessing these corridors.

b) The various agreements that were transferred in the late 1990's expire between 2016 and 2019. The current annual cost of the agreements is $29,990.45.

2.0-VECC-7

Reference: 2/T3/Appendix A/Distribution System Plan/pg.62/72

a) Please provide the actual new customer and service upgrade costs for 2008 through 2013. Please explain how the 2015 through 2019 cost of $907,000 was derived.

b) Please provide the actual line rebuild costs for 2008 through 2013. Please explain how the $3,400,000 in estimated costs for this program for 2016 through 2019 was derived.

RESPONSE:

a) See table below for 2008 -2013 actual and 2014 forecast. As described in Section 5.4.1(c) at page 52 of the Distribution System Plan (Exhibit 2, Tab 3, Schedule 1, Appendix A), future amounts are budgeted based on five-year rolling averages. The amounts from prior years are adjusted for inflation in considering this average.

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast
Actual Cost	$578,716	$633,952	$696,931	$776,812	$996,496	$913,115	$912,104
X = Number of Years to Adjust for 2015 Inflation	7	6	5	4	3	2	1
Inflation Factor (1.02^X)	1.15	1.13	1.10	1.08	1.06	1.04	1.02
Actual in 2015$	$664,762	$713,932	$769,469	$840,846	$1,057,490	$950,004	$930,346

b) See table below for 2008-2013 actual costs. Please note that the Line Rebuild program was only recently initiated as the Conductor Replacement program neared completion. The $3,400,000 in estimated costs for this program for 2016 through 2019 was derived by multiplying the program target of 400 distribution poles per year by an estimated unit cost of $8,500 per pole.

Project/Program	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual
Conductor Replacement	2,255,252	4,107,674	3,256,457	3,278,312	3,172,733	1,566,869
Line Rebuilds					1,156,642	415,684
Express Feeder		102,393	319,089			400,288
Desb 2nd Feeder			148,446			
Other	175,639		87,439	39,568		
Total	$2,430,891	$4,210,067	$3,811,431	$3,317,880	$4,329,375	$2,382,841

(page left blank intentionally)

2.0-VECC-8

Reference: 2/T8/S1/pg.1

a) Please explain what metrics, service quality indicators or other benchmarks are being used to evaluate the success of the distribution system plan.
b) API's service reliability indicators (excluding loss of supply) do not show any improvement since 2009. Please explain how the plan presented in this application will rectify this.

RESPONSE:

a) API regularly submits performance information such as reliability statistics and ESQR reports to the Board through the RRR filing requirements. API notes that Distribution System Plan Implementation Progress has recently been included as a performance measurement under RRR filings.

b) Please refer to Section 5.2.3(c) of API's Distribution System Plan at Exhibit 2, Tab 3, Schedule 1, Appendix A.

(page left blank intentionally)

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?

RESPONSE:

a) See response to 3-VECC-17c for Regulatory Debits and 3-Energy Probe-19g for Costs and Expenses of Merchandising, Jobbing, etc.

b) See response to 3-VECC-17c for Regulatory Debits and 3-Energy Probe-19g for Costs and Expenses of Merchandising, Jobbing, etc.

c) See response to 3-Energy Probe-19g for Costs and Expenses of Merchandising, Jobbing, etc.

(page left blank intentionally)

3.0 –Staff -19

Reference: Exhibit 3/Tab 1/Sch. 2/Appendix A – Elenchus Report/Sch. 2/p. 2
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?

RESPONSE:

a) Without the Time variable, the results are as follows:

	Coefficient	Standard Error
Constant	5,722,870	1,298,650
Monthly HDD	9,463.82	277.947
Monthly CDD	67,488.9	11,551.3
Peak Days	120,719	60,430.4

b) Without the Time and Peak Days variables, the results are as follows:

	Coefficient	Standard Error
Constant	8,296,700	165,236
Monthly HDD	9,347.92	276,160
Monthly CDD	65,886.2	11,707.2

c) The explanatory variables, Monthly HDD, Monthly CDD, Peak Days, and Time were chosen for consistency with Algoma's 2010 Cost of Service application. In the 2015 rate application, the inclusion of Time has added no value. Having removed the Time variable, the adjusted R-squared has improved from 0.938450 to 0.939062, and the standard error of the regression improves from 659,980 to 658,611. When PeakDays is removed as well, the Adjusted R-squired deteriorates to 0.937103, and the standard error of the regression increases to 669,117.

Having explained less than 0.5% of the forecast in the Test Year, and not substantially impacted the coefficients or standard error of the other explanatory variables, the inclusion of Time has not substantially altered the robustness of the model. However, it is clear that it adds no value, and will be removed from an update.

With Time removed, Peak Days has a coefficient 1.998 times its Standard Error. At 2.0, we could say with greater than 95% confidence that the variable has value. At 1.998 times, it is much more likely than not that Peak Days is improving the accuracy of the Load Forecast.

Algoma Coalition
Forecasting

6. We understand this rate application is forward looking. Please explain the forecasting methodology for the forward looking portion of this rate application.

RESPONSE:

Algoma Power's cost of service application is based on a 2015 Test Year. The Company forecasts customer load, number of customers, other revenue, operating expenditures, and capital expenditures for the 2015 Test Year.

The load forecast is based on a multifactor regression analysis in accordance with the Filing Requirements. The load forecasting methodology and assumptions are included in a report prepared by Elenchus Research Associates in Exhibit 3, Tab 1, Schedule 2, Appendix A. The forecast of API customers for 2015 is based on historical trending, including new/loss customers and customer transfers between different rate classifications, plus known new general service customers. Other revenue is based on the level of historical transactions in prior years normalized for usual events.

The number of FTE's and compensation provides the foundation for the operating and capital expenditures forecast. As outlined in the employee compensation of the application (Exhibit 4, Tab 4, Schedule 1) salary increases are based on market information provided by the HayGroup and union contracts. Non-labour costs and contractor costs are based on historical costs, known future costs and inflationary estimates.

Determination of capital projects is based on the asset management plan (Exhibit 2, Tab 3) and new customer driven work. Operating expenditures are based on maintenance requirements and ongoing administrative support plus/minus new initiatives or efficiency gains.

The 2015 Test Year forecast was prepared by API's staff with subsequent review and approval by senior management. Algoma Power's Board of Directors reviewed the rate application forecast before filing with the OEB.

Algoma Coalition
Street Lights

7. We understand that street lights are an asset in the General Service class. Please provide the number and location of all such street lights.

RESPONSE:

See Algoma Coalition #8 for table with street light locations.

Streetlight connections are no different than Sentinel or signal light connections. Sentinel or signal lights have always been treated as small commercial or small general service customers. Under the current rate structure, the Sentinel or signal lights are treated as R1 customers and are eligible for RRRP. API tried unsuccessfully to persuade the Board to allow the RRRP formula to apply to streetlight classifications in the last rate application. The Board denied the request. API maintains its belief that the assets and costs to serve the streetlights are no different than small general service or sentinel/signal light connections.

(page left blank intentionally)

Algoma Coalition
Street Lights

8. Please provide a breakdown of the number of street lights by municipality and/or other customers (ex. the Province).

RESPONSE:

Due to customer confidentiality, API has prepared the report with generic names for each streetlight customer grouped according to question.

Customer	Number of Street Lights
Municipalities	
Community 1	31
Community 2	391
Community 3	71
Community 4	5
Community 5	28
Community 6	105
Community 7	3
Community 8	3
Community 9	68
Community 10	34
First Nation Communities	
Community 11	16
Community 12	19
Community 13	87
Other Customer	
Ministry of Transportation (MTO)	152
Other	5
Total	1,018

(page left blank intentionally)

Algoma Coalition
Street Lights

9. Please provide the cost of operation and maintenance of street lights and explain how these compare with other general service class assets.

RESPONSE:

Please refer to answer to Algoma Coalition #7.

(page left blank intentionally)

Algoma Coalition
Street Lights

10. Please explain how the size of the street light asset base compares to the total asset base in the General Service class (i.e. the percentage of the total general service class asset base for which street lights account).

RESPONSE:

The street light asset base is approximately 3% of the total asset base.

(page left blank intentionally)

Algoma Coalition
Street Lights

11. Please provide the annual consumption for street lights and explain how this compares to annual consumption of the remaining general service class assets.

RESPONSE:

Customer Class	kWh	kWh
Streetlights	804,690	0.41%
R1 (includes residential and small general service)	104,826,589	53.35%
R2 (includes larger General Service)	83,171,116	42.33%
Seasonal	7,680,066	3.91%
	196,482,461	100.00%

The streetlights customer class represents less than one percent of annual consumption.

(page left blank intentionally)

Algoma Coalition
Smart Meters

16. Please explain how the installation of smart meters has affected Algoma Power's rates.

RESPONSE:

Smart Meter Capital and Incremental O&M Cost Recovery

Per decision in EB-2012-0104, API's 2013 incentive rate-setting proceeding, the smart meter costs relating to the Residential R1 rate class were approved to be recovered within RRRP funding. The costs attributable to the Seasonal rate class are being recovered in the form of 2 rate riders: the Smart Meter Deferred Revenue Rate Rider of $3.57 per month (effective until December 31, 2016) and the Smart Meter Incremental Revenue Rate Rider of $4.69 per month (effective until December 31, 2014).

Stranded Meter Cost Recovery

Within Exhibit 2, Tab 2 of this Application, API is requesting recovery of the stranded meter costs. The amounts related to the Residential R1 rate class are being requested to be recovered within RRRP funding, while the Seasonal rate class portion is to be recovered in the form of a $2.27 per month Stranded Meter Disposition Rate Rider that is to end after 12 months.

(page left blank intentionally)

<u>3-Energy Probe-12</u>

Ref: Exhibit 3, Tab 1, Schedule 2, Appendix A, Schedule 2

a) What does STEI stand for? (page 4, line 7)

b) Are the customer numbers used in the Elenchus report year end or the average number of customers per year? If the latter, is the average based on the opening and closing numbers for the year or the average number for each month?

c) For each rate class, please provide the most recent number of customers available in 2014 along with the figure for the corresponding month in 2013.

RESPONSE:

a) STEI ought to read API.

b) The data provided to Elenchus and used in their report is the year end customer counts.

c) The most recent customer counts available for 2014 are the June 30 customer counts. A comparison of the June 30, 2013 and the June 30, 2014 customer counts by classification is shown below.

Customer Classification	June 30, 2013	June 30, 2014
Residential – R1	8,240	8,338
Residential – R2	50	44
Seasonal	3,329	3,255
Street Lighting	1,018	1,018

(page left blank intentionally)

<u>3-Energy Probe-13</u>

Ref: Exhibit 3, Tab 1, Schedule 2, Appendix A, Schedule 3

a) Please confirm that the forecasted shift of 107 customers from the seasonal to residential R1 class means 107 customers in 2014 and a further 107 customers in 2015.

b) Please explain why the shift in volumes is 321,000 in both 2014 and 2015. In particular, why isn't the shift in 2015 double this amount, or 642,000 reflecting the additional volumes shifted in 2015 compared to 2014 for the additional customers switching in 2015?

RESPONSE:

a) Confirmed, it is forecasted that 107 customers will shift from Seasonal to R1 in 2014, and a further 107 customers will shift in 2015.

b) Year-End value for 2014 was used for the opening value for 2015, so essentially the transfer of 321,000 kWh from Seasonal to R1 for 2015 was applied to an amount that already reflected the 2014 transfer from Seasonal to R1. However, this method has failed to capture the change in the overall load forecast for 2014 and 2015 in the Seasonal and R1 rate classes. A correct methodology would be to calculate R1 kWh as 153,666,454 kWh * 0.682577 = 104,889,187 kWh (unadjusted); 104,889,187 kWh + 642,000 = 105,531,187 kWh. The corrected methodology applied to Seasonal would result in 7,708,542 kWh.

This error in the Load Forecast has less than a 1% impact on the load forecast. API believes the impact is not material, a new load forecast and all the impacted evidence, including an updated Cost Allocation Model will be used when implementing the OEB's Decision.

(page left blank intentionally)

3-Energy Probe-14

Ref: Exhibit 3, Tab 1, Schedule 2, Appendix A, Schedule 2

a) **Please explain how the normalized historical figures for 2006 through 2013 shown in Table 2-3 were calculated. In particular, are the estimates based on a forecast using normalized (i.e. 10 year average) figures for HDD and CDD with no other changes to that used in the regression equation?**

b) **Please provide a revised Table 2-3 that calculates normalized figures for 2006 through 2013 based on actuals and the difference in degree days times the appropriate coefficient. In particular, please calculate normalized actual equal to actual plus HDD coefficient times (normal HDD minus actual HDD) plus CDD coefficient times (normal CDD minus actual CDD).**

RESPONSE:

a) The normalized historical figures are calculated based on the regression provided at Table 2-1 of the referenced document. Therefore, each month is computed as the constant plus the normal HDD times the HDD Coefficient plus the normal CDD times the CDD Coefficient plus the number of working days in the given month times the PeakDays Coefficient plus a Time Counter times the Time Coefficient.

b) Please see the table below:

Annual Actual vs. Actual Adjusted for Weather WSL2				
	WSL2	% Change	Normalized Value	% Change
2006	150,668,796		153,598,756	
2007	153,919,598	2.2%	152,626,450	-0.6%
2008	157,822,157	2.5%	156,071,170	2.3%
2009	160,752,853	1.9%	158,422,161	1.5%
2010	146,405,213	-8.9%	148,579,520	-6.2%
2011	149,046,161	1.8%	149,398,219	0.6%
2012	147,470,689	-1.1%	150,300,573	0.6%
2013	155,660,648	5.6%	158,216,640	5.3%

(page left blank intentionally)

<u>3-Energy Probe-15</u>

Ref: Exhibit 3, Tab 1, Schedule 2, Appendix A, Schedule 2 & API Load Forecast Model (Excel Spreadsheet)

a) The spreadsheet provided does not contain all the information needed to replicate the estimated regression equation. In particular, it does not include the historical data for November and December of 2005.

Please provide the complete historical data set needed to estimate the regression equation found in the spreadsheet.

b) The spreadsheet provided has most of the links between the sheets removed.

Please provide the excel spreadsheet requested in part (a) above with all the links still in place.

RESPONSE:

a) Please see the attached spreadsheet with the two lines restored.

b) The spreadsheet provided was produced by a mix of manual and program generated worksheets. To provide a spreadsheet with links would require creation of the links where none had been used in the past.

The attached model is the filed model, with the exception that the 2 months of data requested have been added.

(page left blank intentionally)

3-Energy Probe-16

Ref: Exhibit 3, Tab 1, Schedule 2, Appendix A, Schedule 2

a) **Please explain why the time variable has been included in the equation given that it is not statistically significant.**

b) **Did Elenchus try any other explanatory variables, such as number of days in the month, spring-fall flag, summer flag, etc.? If not, why not? If yes, please provide a live Excel spreadsheet that shows the variables used and the subsequent regression equations.**

RESPONSE:

a) Please see the response to 3.0 VECC – 11.

b) Elenchus only ran the model with the explanatory variables selected. These were used for consistency with the 2010 Cost of Service application.

(page left blank intentionally)

<u>3-Energy Probe-17</u>

Ref: Exhibit 3, Tab 1, Schedule 2, Appendix A, Schedule 4

a) **Please explain why API has not forecast any increase in kWh's or kW's associated with the five large use customers for 2014 and 2015 despite an increase in every year from 2008 through 2013.**

b) **Please provide the most recent year-to-date kWh's and kW's available for 2014 for the 5 large use customers, along with the figures for the corresponding period in 2013.**

RESPONSE:

As a preamble to the responses to this interrogatory it is important to note that the reference to five large use customers refers to five of the larger customers within API Residential – R2 customer class. These are not defined as are the typical “Large Use” customer classification found in other Ontario distributors.

These five customers (four as of January 2010 as one customer consolidated two services) are distinct customers within the Residential – R2 class and have traditionally been isolated for forecasting reasons due to their individual usage patterns. One customer is a forestry operation with an associated town site; it is a licenced distributor and therefore an embedded distributor of API. For purposes of rate protection, it has been classified as a Residential – R2 customer. This customer is primarily resource based and its demand and throughput are completely dependent on resource availability which is not predictable.

A second customer is associated with winter recreation. The timing and extent of its demand and throughput are completely dependent on weather related events (i.e., snowfall). Historical patterns are volatile and unpredictable.

The remaining customers are resource based; mining and forestry. Throughput and demand of both are tied to commodity pricing and supply of raw materials. These customers have historically been segregated for forecasting purposes due to the volatility and unpredictability of their loads.

a) As discussed in the preamble to this interrogatory, each of these customers is unique due to the volatility and unpredictable nature of their loads which makes them impractical to forecast in the conventional sense. In the absence of clear direction from the customer with respect to planned load increases or decreases, API cannot reasonably forecast a change; therefore API forecast is to maintain the pattern of historical throughput and demand.

b) The following table provides a year over year comparison of throughput and demand for the period of January 1st to June 30th. The demand is the accumulated six month billing demand for each customer.

Period	Customer "A"		Customer "B"		Customer "C"		Customer "D"	
	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Jan. 1 to June 30, 2013	24,942,268	38,999	4,579,410	8,518	1,664,196	7,439	779,743	2,178
Jan. 1 to June 30, 2014	24,315,925	38,636	4,713,540	8,482	1,587,125	6,854	596,314	1,537
Year Over Year Change	(626,343)	(363)	134,130	(36)	(77,071)	(585)	(183,429)	(641)

3-Energy Probe-18

Ref: Exhibit 3, Tab 4, Schedule 2

Please provide the most recent year-to-date actual figures for 2014 that are currently available in the same level of detail as that found in Appendix 2-H. Please also provide the figures for the corresponding period in 2013.

RESPONSE:

The year-to-date figures as at June 30 for 2013 and 2014 for Appendix 2-H are shown below.

	Appendix 2-H		
	Other Operating Revenue Offset Table		
OEB Account	**Description**	**2013 Actual YTD June 30**	**2014 Actual YTD June 30**
4086	SSS Administration Revenue	(17,265)	(17,453)
4082	Retail Services Revenues	(2,758)	(3,137)
4084	Service Transaction Requests (STR) Revenues	(54)	(31)
4210	Rent from Electric Property	(122,824)	(119,208)
4215	Other Utility Operating Income	-	-
4220	Other Electric Revenues	(1,632)	(20,029)
4225	Late Payment Charges	(50,110)	(70,307)
4235	Miscellaneous Service Revenues	(14,875)	(24,100)
4305	Regulatory Debits	334,510	357,420
4325	Revenues from Merchandise, Jobbing, Etc.	(18,575)	(257,534)
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	17,701	277,553
4355	Gain on Disposition of Utility and Other Property	-	-
4360	Loss on Disposition of Utility and Other Property	10,897	(22,954)
4398	Foreign Exchange Gains and Losses, Including Amortization	69	261
4405	Interest and Dividend Income	(52,265)	(38,581)
	Other Operating Revenue Offset	82,820	61,899
Specific Service Charges		(14,875)	(24,100)
Late Payment Charges		(50,110)	(70,307)
Other Distribution Revenues		(144,532)	(159,858)
Other Income and Expenses		292,337	316,164
Total		82,820	61,899

3-Energy Probe-19

Ref: Exhibit 3, Tab 4, Schedule 1

a) **Please explain why the revenues in account 4086 are forecast to be lower in 2014 and 2015 as compared to previous years given that the number of customers is increasing.**

b) **Please explain why there is no revenue forecast for accounts 4082 and 4084 for 2014 and 2015 despite revenue being recorded in 2013.**

c) **Please explain why the revenue in account 4210 was significantly higher in 2012 than it was in other years.**

d) **Please explain the decrease in revenues forecast in account 4210 in 2014 and 2015 relative to 2013.**

e) **Please explain the decrease in account 4225 in 2015 relative to 2011 through 2013.**

f) **Please explain the decrease in account 4235 in 2015 relative to 2012 and 2013.**

g) **In 2011 through 2013, the net revenue in accounts 4325 and 4330 was between $15,000 and $20,000. Please explain why the net revenue forecast for 2014 and 2015 is $0.**

h) **Does the interest income in account 4405 include interest earned and payable related to deferral and variance accounts? If yes, please provide the amount in account 4405 excluding any interest associated with deferral and variance accounts.**

i) **Does API have any microFit customers? If yes, please provide the average number in each of 2011 through 2013 and the forecast for 2014 and 2015. Please also indicate where the revenue associated with the customers is shown and provide the amount for each year of 2011 through 2015.**

RESPONSE:

a) The revenue in SSS administration revenue, account 4086, is forecast lower in 2014 and 2015 as a result of budgeting assumptions regarding retailer enrollment.

b) The revenue in accounts 4082 and 4084 was not forecast for 2014 and 2015 due to the immaterial nature of these accounts and the lack of any history for these accounts in the previous accounting system.

c) The revenue in rent from electric property, account 4210, was high in 2012 as a result of changing from the cash basis to accrual basis of accounting for pole rentals. Therefore in 2012 the revenue recorded was the cash received for 2011 and the accrued revenue for 2012.

d) The revenue in rent from electric property, account 4210, was high in 2013 as a result of $25,613 billed in 2013 for 2012 that was not accrued in 2012. The amount in account 4210 should be approximately $245,000 based on current pole rentals.

e) The revenue in late payment charges, account 4225 was forecast as an average of the prior years and then adjusted slightly lower due to the expectation that the move to monthly billing would reduce the late payment charges.

f) The revenue in miscellaneous service revenue, account 4235 was forecast as an average of the prior years and then adjusted slightly lower due to the recent OEB distribution system code changes with respect to low income customers the expectation is that there will be a decrease in customer disconnections.

g) The revenues, account 4325, and costs, account 4330, of merchandising, jobbing, etc., are customer driven and revenue neutral. Due to the difference in timing of when the costs are incurred and the billing is performed there will be a variance in the accounts. The accounts will net to zero over time, therefore no revenue or costs are forecast for these accounts.

h) The interest income in account 4405 does include interest on deferral and variance accounts. The balances without the interest on deferral and variance accounts are shown below.

Account 4405 - Interest and Dividend Income					
	2011	**2012**	**2013**	**2014**	**2015**
Balance	-$ 142,837	-$ 113,770	$ 94,130	-$ 14,100	-$ 10,000
Less Interest on Deferral and Variance accounts	- 90,934	- 95,042	113,572	- 4,100	
Balance	-$ 51,903	-$ 18,728	-$ 19,442	-$ 10,000	-$ 10,000

i) Yes. In all of the years, the balance has been recorded in OEB 4235 Miscellaneous Service Revenues as shown below.

	Year				
	2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year
Average # of Active microFIT	25	67	94	113	118
$ Amount (Revenue)	(1,550)	(4,023)	(5,841)	(0)	(6,000)

(page left blank intentionally)

3.0 –VECC - 9

Reference: E3/T1/S2/pg.3
E1/T2/S4/pg.2

Table 3.1.2.2 reports customer and connection counts for 2009 through 2015.

a) Are the customer and connection counts shown average annual or year-end values?

RESPONSE:

a) The customer/connection counts in Table 3.1.2.2 are year-end values.

(page left blank intentionally)

3.0 –VECC - 10

Reference: E3/T1/S2/Appendix A/Schedule 1/pg.1
E3/T1/S2/Appendix A/Schedule 2/pg.2

a) The first reference notes that the R2 class includes large users (i.e. customers over 5 MW). Are the five customers who are excluded from the WSL kWh all large users? If not, what is the average load for each of those who are not?
b) Does API have any additional large users (i.e. customers with average monthly peak loads greater than 5 MW) that are not included in the five customers excluded from the WSL kWh? If so, why were these customers not also excluded?
c) How did Elenchus establish which customers should be excluded from the WSL kWh?
d) Were alternative model specifications tested where either more/fewer customers were excluded and, if so, what were the results?

RESPONSE:

As a preamble to this response, API references its response to Interrogatory 3-Energy Probe-17. In that interrogatory response, API discusses the nature and load patterns of the five customers that had been isolated for forecasting purposes.

a) None of these five customers are classified as a Large Use class of customer in the traditional sense. API has used the term large user in the generic sense relating to their relationship with other customers in the Residential – R2 class. All of these customers are Residential – R2 class. The largest of the customers does have a monthly billing demand greater than 5 MW; normally this customer will have a billing demand of 6.0 to 6.5 MW. The remaining customers have an average monthly billing demand of 1.0 MW.

b) API does not have another customer with a monthly billing demand greater than 5 MW.

c) These customers were made known to Elenchus by API. Due to the historical usage patterns API normally isolates these customers for forecasting purposes. As discussed in 3-Energy Probe-17, these customers are unique from the perspective that they are primarily driven by resource availability and pricing. Their throughput and demand volatility and relative combined contribution to the class load can result in unrealistic forecasts.

d) There were no other model specifications tested.

3.0 –VECC -11

Reference: E3/T1/S2/Appendix A/Schedule 2/pg.2

a) Why was the time trend variable included when the coefficient is statistically insignificant?

RESPONSE:

a) Algoma's Load Forecast in support of its 2010 Cost of Service application included a time trend variable. In that application, the time trend variable was statically significant. The 2015 Cost of Service application preserved the time variable to be consistent in methodology.

(page left blank intentionally)

3.0 –VECC - 12

Reference: E3/T1/S2/Appendix A/Schedule 2/pg.4

a) Please confirm that the reference at line 7 should be to API and not STEI.

RESPONSE:

a) API confirms that the reference at line 7 should be to API and not STEI.

(page left blank intentionally)

3.0 –VECC -13

Reference: E3/T1/S2/Appendix A/Schedule 3/pg.1

a) Please confirm that the average use for Seasonal customers is roughly 3,000 kWh per year.
b) Please confirm that API has verified that all Seasonal customers transferred to the R1 class meet the eligibility requirements (i.e., occupy the premises as a residence for at least eight months of the year).
c) Would it be reasonable to expect that Seasonal customers who qualify as R1 customer would use more than the Seasonal class' annual average kWh? If not, why not?
d) Has API reviewed the average annual use for those Seasonal customers who have recently (e.g. in the last 3 year) transferred to the R1 class? If so, what was the average use?
e) If not, please undertake such an analysis - provided the required data are readily available.

RESPONSE:

a) API confirms that the average use per customer in the Seasonal customer class is roughly 3000 kWh per year. Further, the evidence presented shows that this average use per customer has declined from a value of 3400 kWh in 2009 to 2565 kWh in 2013.

b) Yes, API confirms that all Seasonal customers transferred to the Residential – R1 class meets the eligibility requirements. API requires that all customers requesting to be transferred from the Seasonal class to the residential – R1 class complete and sign a questionnaire confirming their eligibility.

c) Yes, it would be reasonable to expect that Seasonal customers who qualify as a Residential – R1 customer would use more than the Seasonal class' annual average kWh.

d) No, API has not reviewed the average annual use of those Seasonal customers that have recently transferred to the Residential – R1 class. On the basis of the response to part a) of this Interrogatory, it is evident that the average annual use of the remaining Seasonal class customers is declining as more customers transition from the seasonal class to the residential – R1 class.

e) This data is not readily available. The API billing system does not include a unique identifier to select only those customers that have transitioned from the seasonal class to the Residential – R2 class.

3.0 –VECC -14

Reference: E3/T1/S2/Appendix A/Schedule 3/pg.3

a) The forecast change in number of Seasonal customers for 2014 and 2015 appears to be based on the change observed for 2013. Please explain why this is a better basis for forecasting than using an average over the last say 3-4 years.

RESPONSE:

a) API has based the 2014 and 2015 forecast for the change in Seasonal customers on the change observed in 2013. API chose the 2013 value based on customer interactions and feedback with front line and customer service staff. Seasonal customers are continually becoming aware of the price differential between the Residential – R1 class and the Seasonal class and questioning to eligibility requirements. This increased awareness of the eligibility criteria has prompted an increase in enquiries from Seasonal customers.

On the basis of interactions between API's frontline staff and its customers, API feels that the 2013 value is an appropriate indicator for 2014 and 2015.

(page left blank intentionally)

3.0 –VECC -15

Reference: E3/T1/S2/Appendix A/Schedule 4/pg.2

a) It is noted that the kWh forecast for R2 customers increases over the 2013-3015 period (per Table 4-2). However the forecast kW (per Table 4-3) remains unchanged. Please reconcile.

RESPONSE:

a) The forecasted change on energy throughput of the Residential – R2 for 2013 to 2014 and for 2014 to 2015 is less than 10,000 kWh or 0.01% per annum.

Based on discussions with its customers, API has no evidence of substantive changes, either increases or decreases in its billing demand for the forecast period. In API's opinion, the 0.01% forecasted change in throughput is not significant enough to cause a change in billing demand.

(page left blank intentionally)

3.0 –VECC -16

Reference: E3/T1/S2/Appendix A/Schedule 6/pg.2-4

a) Please provide any reports from the OPA regarding API's CDM results for 2013.
b) What is the basis for the 500,000 kWh forecast for 2015 of the savings continuing to persist from 2014 CDM programs (Tables 6.2 and 6.3?
c) What is the basis for the 250,000 kWh CDM savings forecast for 2015 from 2015 CDM programs (Tables 6.2 and 6.3)?
d) Why is there no ½ year adjustment include for the impact of 2013 programs in 2015?

RESPONSE:

a) Please find attached the Q4 2013 Preliminary Results Update report from the OPA.

b) It is recognized that the CDM programs in a year are not in effect for the full year, although persistence of previous year's programs will be. Therefore, the actual impact on the load forecast for the first year of the program should not be the full annualized amount.

c) Please refer to b) above.

d) The impact of 2013 CDM programs were implicitly captured in the un-adjusted load forecast by use of 2013 actual data in the regression model.

(page left blank intentionally)

Ontario Power Authority
Conservation & Demand Management Status Report

Q4 2013 Preliminary Results Update

Algoma Power Inc.

Unverified OPA-Contracted Province-Wide CDM Program Progress at a Glance

Unverified Progress to Targets	Incremental Q4-2013	Program-to-Date Progress Towards OEB Target				Rank (of 76)
		Scenario 1		Scenario 2		
		Savings	%	Savings	%	Scenario 2
Net Peak Demand Savings (MW)	**0.0**	**0.2**	15%	**0.2**	15%	**70**
Net Energy Savings (GWh)	**0.1**	**3.1**	42%	**3.1**	42%	**69**

Program-to-Date towards Target: Combination of verified (2011-12) and unverified (2013) results. To align with savings counted towards OEB targets, peak demand is represented by annual savings in 2014 and energy is represented by the cumulative savings from 2011-2014.

Scenario 1: Assumes that demand response resources have a persistence of 1 year. Official reporting policy for demand response resources.

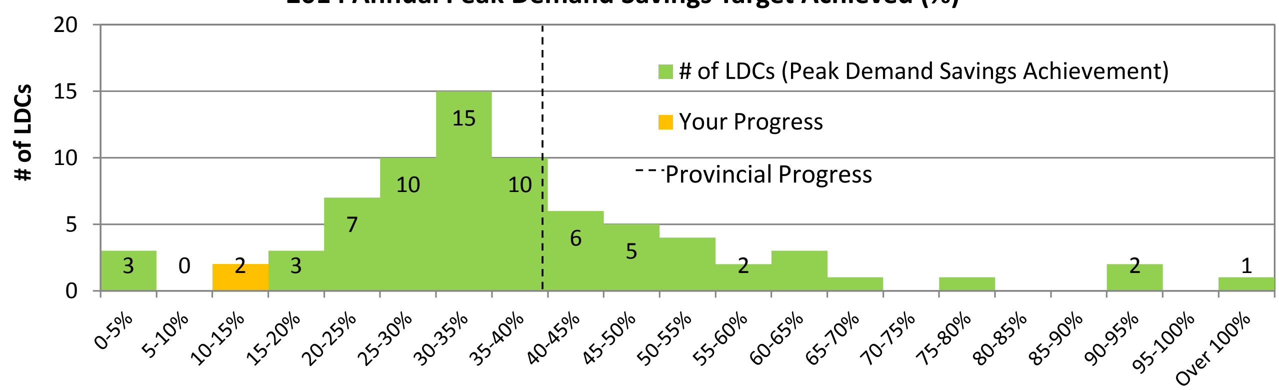
Scenario 2: Assumes that demand response resources remain in your territory until 2014. Used to better assess progress towards demand targets.

Rank: Sorts each LDC by % of peak demand or energy target achieved as of the current reporting period using Scenario 2.

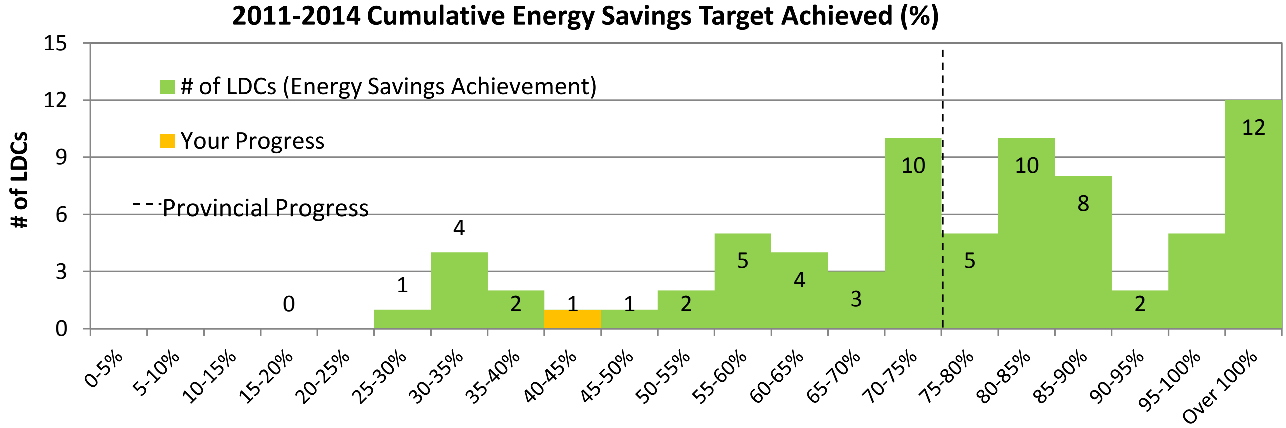
Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)

2014 Annual Peak Demand Savings Target Achieved (%)



2011-2014 Cumulative Energy Savings Target Achieved (%)



Questions? Please check the "About this Report" Section on page 2, Table 5 on page 9 and "Reporting Methodology" on page 10.
More Questions? Please contact LDC.Support@powerauthority.on.ca

Message from the Vice President

I am pleased to present our Q4 2013 LDC report. We continue to achieve great progress across all sectors. Provincially we have achieved 83% of the cumulative 6,000 GWh energy target and progress towards the 1,330 MW demand target increased from last quarter to 46%.

A few highlights of our current activities during this reporting period:

- Take up in the LDC Conservation Fund Innovation Stream continues to grow.
- The new roof-top unit (RTU) incentives for RETROFIT PROGRAM came into effect January 1, 2014. Non-lighting measures continue to play an important role towards achieving targets.
- Aboriginal Program has started to contribute to savings in Q4! Over 250 completed home retrofits have been received to date.
- Final wave of enhancements to enable the 2015 Program extension are underway
- Achievable Potential study to estimate realistic potential of EE and DR programs in Ontario is in progress

We look forward to continuing to work together on evolving our Conservation Programs in 2014, and engaging channel partners across all sectors to further drive participation.

We encourage you to continue to contact us and tell us your ideas and success stories so we can share our experiences across the province.

Please contact the OPA Conservation Business Development team at ldc.support@powerauthority.on.ca with any questions regarding this report.

Congratulations on another successful quarter and wishing you a great year in 2014!

Sincerely,

Andrew Pride

About this Report

This report contains:

- Peak demand and energy savings for OPA-Contracted Province-Wide programs (does not include Ontario Energy Board (OEB) approved CDM programs or other LDC conservation efforts)
- Progress as of the end of Q4 2013 using unverified quarterly results for 2013 and final verified results for 2011-12
- Program activity data (i.e. projects completed, appliances picked up) completed on or before December 31st, 2013 and received and entered into the OPA processing systems as per the dates specified in Table 5
- Updates to the previous quarter's participation as a result of further data received
- Information to assist the LDC in reconciling internal data sources with the data contained in this report. Table 5 contains:

    1 The date in which savings are considered to 'start';
    2 At what point the data becomes available to the OPA;
    3 The expected probability and magnitude of updates to the data as more information becomes available.
- iCON CRM Post Stage Retrofit Report data queried on January 13th, 2013
    - Retrofit projects completed after December 31, 2011 will be tracked as part of the Business program only
- Preliminary results for peaksaverPLUS® representing customers that have signed a Participant Agreement and information has been successfully uploaded into the RDR settlement system
- peaksaver PLUS® reporting is split into two line items: Switch/Thermostat and IHD

2011-2014 Summary: Net Peak Demand Savings Achieved (MW)

This section provides a portfolio level view of net peak demand savings procured to date through Tier 1 programs.
Table 1 presents:

- Net peak demand savings results from 2011 to Q4 2013 listed by implementation period, status (i.e. final or reported) and summarized by resource type (i.e. energy efficiency or demand response)
- Net annual peak demand savings that are expected to persist through to 2014 from program activity completed as of Q4 2013 using both Scenarios 1 and 2
- A comparison between reported, unverified results and final, verified results
- Energy efficiency resources reported with persistence according to the effective useful life of the technology

Figure 1 presents:

- Net peak demand savings results from 2011 to date using Scenario 1 for demand response resources (persistence of 1 year)

Please note: Demand response resources are only presented in the final quarter of each year and the current reporting quarter (i.e. Q4 2011, Q4 2012, and Q3 2013). Figures below and tables 3B and 4B present demand response in each quarter to display any changes that may have occurred quarter over quarter.

Table 1A: Net Peak Demand Savings at the End-User Level (MW)

#	Implementation Period	Annual (MW)				
		Scenario 1				Scenario 2
		2011	2012	2013	2014	2014
1	2011 - Final*	0.0	0.0	0.0	0.0	0.0
2	2012 - Final*	0.0	0.1	0.1	0.1	0.1
3	2013 - Reported - Quarter 1			0.0	0.0	0.0
4	2013 - Reported - Quarter 2			0.0	0.0	0.0
5	2013 - Reported - Quarter 3			0.0	0.0	0.0
6	2013 - Reported - Quarter 4			0.0	0.0	0.0
7	2014					
	Energy Efficiency	0.0	0.1	0.2	0.2	0.2
	Demand Response	0.0	0.0	0.0	0.0	0.0
	Net Annual Peak Demand Savings	0.0	0.1	0.1	0.1	0.2
	Unverified Net Annual Peak Demand Savings in 2014:				**0.1**	**0.1**
	2014 Annual Peak Demand Savings Target as per OEB:				**1.3**	**1.3**
	Unverified 2014 Peak Demand Savings Target Achieved (%):				**8%**	**8%**
	Incremental Reported (Unverified)	0.0	0.1	0.0		
	Incremental Final (Verified)	0.0	0.1	n/a		

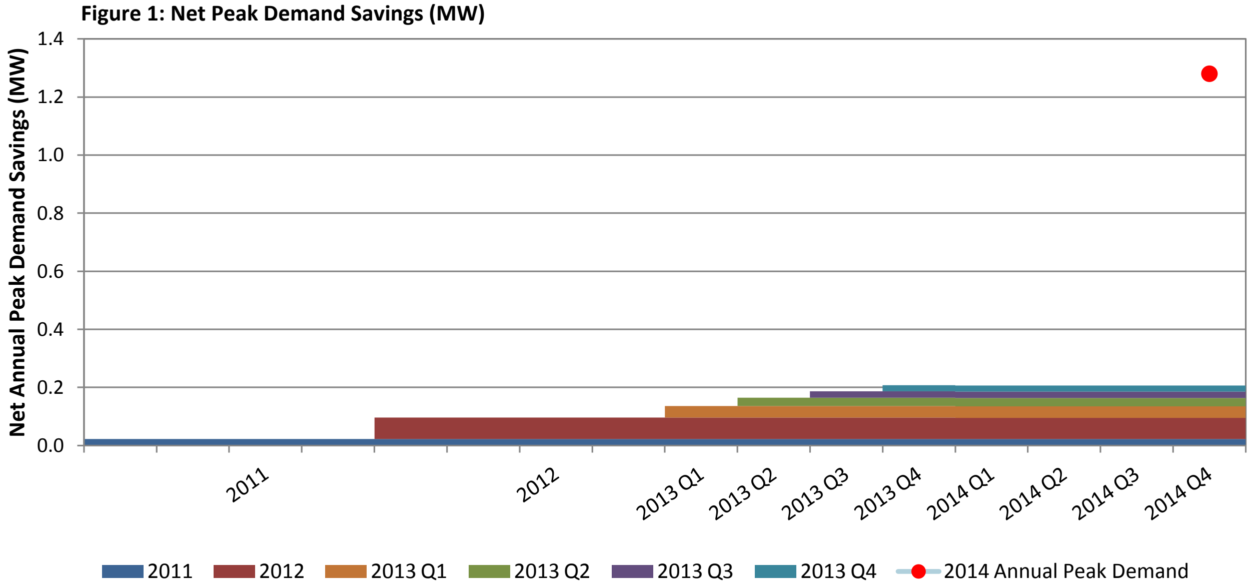
* Drop from 2011 to 2012 due to demand response persistence assumption (scenario 1)

Table 1B: Peak Demand Savings from DR3 Resources

Reported DR3 (Ex Ante) (MW)**	0.0
Contracted DR3 (MW)**	0.0

** Consistent with monthly DR3 reports at the end of each quarter

Figure 1: Net Peak Demand Savings (MW)



Savings Target as per OEB

2011-2014 Summary: Net Energy Savings Achieved (GWh)

This section provides a portfolio level view of net energy savings procured to date through Tier 1 programs.

Table 2 presents net annual energy savings results from 2011 to date listed by implementation period, status (i.e. final or reported) and summarized by resource type. This table aligns with Scenario 1 and presents 2011-2014 net cumulative energy savings expected in 2014 from program activity completed to date. At the bottom of the table a comparison is made between reported results (unverified) and final results (verified) for 2011, 2012, and 2013 year-to-date.

Table 2: Net Energy Savings at the End-User Level (GWh)

#	Implementation Period	Annual (GWh)				Cumulative (GWh)
		2011	2012	2013	2014	2011-2014
1	2011 - Final*	0.2	0.2	0.2	0.2	0.8
2	2012 - Final*	0.0	0.4	0.4	0.4	1.2
3	2013 - Reported - Quarter 1			0.2	0.2	0.4
4	2013 - Reported - Quarter 2			0.1	0.1	0.2
5	2013 - Reported - Quarter 3			0.1	0.1	0.2
6	2013 - Reported - Quarter 4			0.1	0.1	0.2
7	2014					
	Energy Efficiency	0.2	0.6	1.2	1.2	3.2
	Demand Response	0.0	0.0	0.0	0.0	0.0
	Net Energy Savings	0.2	0.6	1.1	1.1	3.0
	Unverified Net Cumulative Energy Savings 2011-2014:					3.0
	2011-2014 Cumulative Energy Savings Target as per OEB:					7.4
	Unverified 2011-2014 Cumulative Energy Target Achieved (%):					41%
	Incremental Reported (Unverified)	0.0	0.4	0.5		
	Incremental Final (Verified)	0.2	0.4	n/a		

* Drop from 2011 to 2012 due to demand response persistence assumption (scenario 1)

Figure 2: Net Cumulative Energy Savings (GWh)

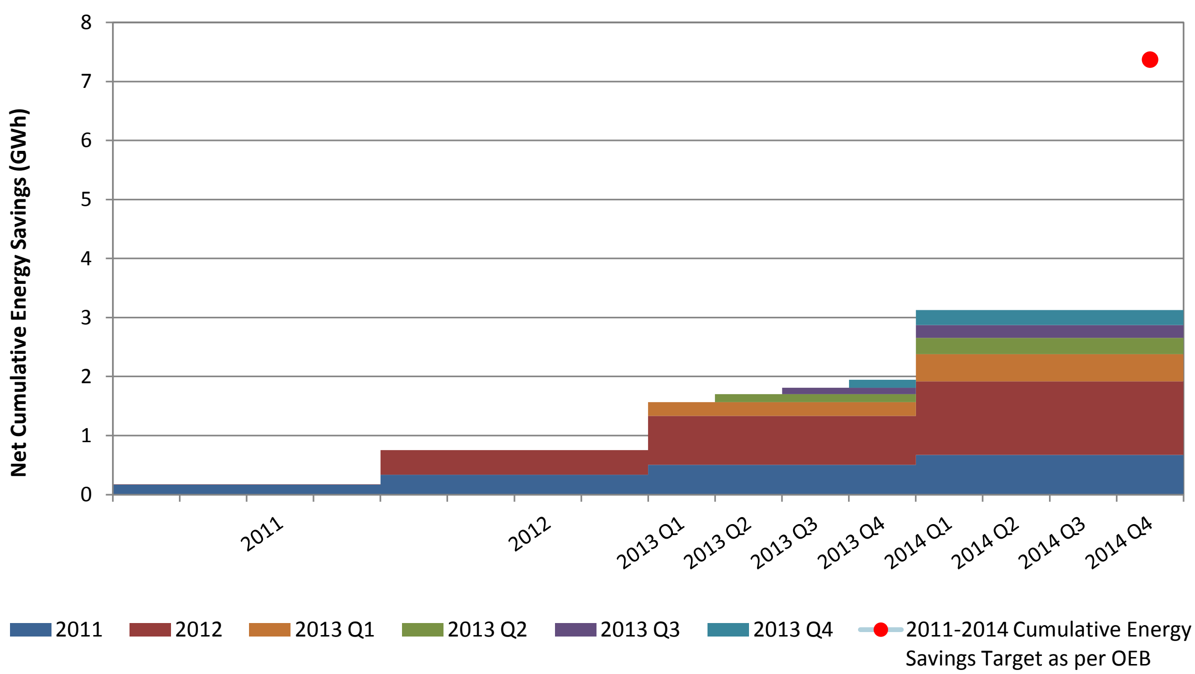


Table 3A: Algoma Power Inc. Initiative and Program Level Savings by Year (Scenario 1)

#	Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Unverified Progress to Target (excludes DR)	
															2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
			2011 Adj.*	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program																
1	Appliance Retirement	Appliances	97	64	44		6	3	3		41,532	25,447	17,045		12	276,357
2	Appliance Exchange	Appliances	7	4	11		1	1	2		790	1,009	3,036		2	11,857
3	HVAC Incentives	Equipment	22	22	62		10	6	17		19,936	11,371	33,495		33	180,847
4	Conservation Instant Coupon Booklet	Measures	1,125	68	231		3	1	-		41,414	3,086	6,926		3	188,765
5	Bi-Annual Retailer Event	Measures	2,102	2,342	2,323		4	3	4		64,865	59,114	67,046		10	570,894
6	Retailer Co-op	Items	-	-	-		-	-	-		-	-	-		-	-
7	Residential Demand Response (switch/pstat)*	Devices	-	-	-		-	-	-		-	-	-		-	-
8	Residential Demand Response (IHD)	Devices	-	-	-		-	-	-		-	-	-		-	-
9	Residential New Construction	Homes	-	-	-		-	-	-		-	-	-		-	-
Consumer Program Total							**24**	**14**	**26**		**168,537**	**100,027**	**127,548**		**60**	**1,228,720**
Business Program																
10	Retrofit	Projects	-	2	2		-	18	9		-	141,850	71,037		27	567,623
11	Direct Install Lighting	Projects	-	39	61		-	42	70		-	170,666	320,827		112	1,152,316
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-		-	-
13	New Construction	Buildings	-	-	-		-	-	-		-	-	-		-	-
14	Energy Audit	Audits	-	-	-		-	-	-		-	-	-		-	-
15	Small Commercial Demand Response (switch/pstat)*	Devices	-	-	-		-	-	-		-	-	-		-	-
16	Small Commercial Demand Response (IHD)	Devices	-	-	-		-	-	-		-	-	-		-	-
17	Demand Response 3*	Facilities	-	-	-		-	-	-		-	-	-		-	-
Business Program Total							**-**	**60**	**79**		**-**	**312,516**	**391,864**		**139**	**1,719,939**
Industrial Program																
18	Process & System Upgrades	Projects	-	-	-		-	-	-		-	-	-		-	-
19	Monitoring & Targeting	Projects	-	-	-		-	-	-		-	-	-		-	-
20	Energy Manager	Projects	-	-	-		-	-	-		-	-	-		-	-
21	Retrofit	Projects	-	-	-		-	-	-		-	-	-		-	-
22	Demand Response 3*	Facilities	-	-	-		-	-	-		-	-	-		-	-
Industrial Program Total							**-**	**-**	**-**		**-**	**-**	**-**		**-**	**-**
Home Assistance Program																
23	Home Assistance Program	Homes	-	-	96		-	-	6		-	-	78,813		6	157,625
Home Assistance Program Total							**-**	**-**	**6**		**-**	**-**	**78,813**		**6**	**157,625**
Aboriginal Program																
24	Aboriginal Program	Homes	-	-	6		-	-	1		-	-	13,839		1	27,678
Aboriginal Program Total							**-**	**-**	**1**		**-**	**-**	**13,839**		**1**	**27,678**
Pre-2011 Programs completed in 2011																
25	Electricity Retrofit Incentive Program	Projects	-	-	-		-	-	-		-	-	-		-	-
26	High Performance New Construction	Projects	-	-	-		-	-	-		-	242	-		-	725
27	Toronto Comprehensive	Projects	-	-	-		-	-	-		-	-	-		-	-
28	Multifamily Energy Efficiency Rebates	Projects	-	-	-		-	-	-		-	-	-		-	-
29	LDC Custom Programs	Projects	-	-	-		-	-	-		-	-	-		-	-
Pre-2011 Programs completed in 2011 Total							**-**	**-**	**-**		**-**	**242**	**-**		**-**	**725**
Other																
30	Program Enabled Savings	Projects	-	-	-		-	-	-		-	-	-		-	-
31	Time-of-Use Savings	Homes	-	-	-		-	-	-		-	-	-		-	-
Other Total							**-**	**-**	**-**		**-**	**-**	**-**		**-**	**-**
Adjustment to Previous Year's Verified Results							**-**	**- 1**	**-**	**-**	**-**	**2,006**	**-**	**-**	**- 1**	**8,024**
Energy Efficiency Total							**24**	**74**	**112**	**-**	**168,537**	**412,785**	**612,064**	**-**	**206**	**3,134,687**
Demand Response Total (Scenario 1)							**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
OPA-Contracted LDC Portfolio Total							**24**	**73**	**112**	**-**	**168,537**	**414,791**	**612,064**	**-**	**205**	**3,142,711**

Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item for 2012 & 2013 will be left blank until the savings are quantified in the 2013 evaluation.

Full OEB Target:	**1,300**	**7,400,000**
% of Full OEB Target Achieved to Date (Scenario 1):	**16%**	**42%**

Table 3B: Algoma Power Inc. Initiative and Program Level Savings by Quarter for current reporting year**

#	Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
			Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013
Consumer Program														
1	Appliance Retirement	Appliances	3	9	8	23	-	1	-	1	1,306	3,272	3,268	9,198
2	Appliance Exchange	Appliances	-	-	7	4	-	-	1	1	-	-	1,914	1,123
3	HVAC Incentives	Equipment	10	13	23	16	3	4	6	5	5,683	6,863	11,928	9,020
4	Conservation Instant Coupon Booklet	Measures	-	13	57	160	-	-	-	-	6	463	1,879	4,578
5	Bi-Annual Retailer Event	Measures	22	1,091	14	1,195	-	2	-	2	570	31,114	367	34,995
6	Retailer Co-op	Items	-	-	-	-	-	-	-	-	-	-	-	-
7	Residential Demand Response (switch/pstat)*	Devices	-	-	-	-	-	-	-	-	-	-	-	-
8	Residential Demand Response (IHD)	Devices	-	-	-	-	-	-	-	-	-	-	-	-
9	Residential New Construction	Homes	-	-	-	-	-	-	-	-	-	-	-	-
Consumer Program Total							**3**	**7**	**7**	**9**	**7,565**	**41,712**	**19,356**	**58,914**
Business Program														
10	Retrofit	Projects	-	-	1	1	-	-	8	1	-	-	67,778	3,259
11	Direct Install Lighting	Projects	29	19	4	9	34	21	5	10	182,232	84,817	14,350	39,429
12	Building Commissioning	Buildings	-	-	-	-	-	-	-	-	-	-	-	-
13	New Construction	Buildings	-	-	-	-	-	-	-	-	-	-	-	-
14	Energy Audit	Audits	-	-	-	-	-	-	-	-	-	-	-	-
15	Small Commercial Demand Response (switch/pstat)*	Devices	-	-	-	-	-	-	-	-	-	-	-	-
16	Small Commercial Demand Response (IHD)	Devices	-	-	-	-	-	-	-	-	-	-	-	-
17	Demand Response 3*	Facilities	-	-	-	-	-	-	-	-	-	-	-	-
Business Program Total							**34**	**21**	**13**	**11**	**182,232**	**84,817**	**82,128**	**42,688**
Industrial Program														
18	Process & System Upgrades	Projects	-	-	-	-	-	-	-	-	-	-	-	-
19	Monitoring & Targeting	Projects	-	-	-	-	-	-	-	-	-	-	-	-
20	Energy Manager	Projects	-	-	-	-	-	-	-	-	-	-	-	-
21	Retrofit	Projects	-	-	-	-	-	-	-	-	-	-	-	-
22	Demand Response 3*	Facilities	-	-	-	-	-	-	-	-	-	-	-	-
Industrial Program Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Home Assistance Program														
23	Home Assistance Program	Homes	58	6	5	27	3	1	1	1	41,600	9,552	6,781	20,880
Home Assistance Program Total							**3**	**1**	**1**	**1**	**41,600**	**9,552**	**6,781**	**20,880**
Aboriginal Program														
24	Aboriginal Program	Homes	-	-	-	-	-	-	-	1	-	-	-	13,839
Aboriginal Program Total							**-**	**-**	**-**	**1**	**-**	**-**	**-**	**13,839**
Pre-2011 Programs completed in 2011														
25	Electricity Retrofit Incentive Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-
26	High Performance New Construction	Projects	-	-	-	-	-	-	-	-	-	-	-	-
27	Toronto Comprehensive	Projects	-	-	-	-	-	-	-	-	-	-	-	-
28	Multifamily Energy Efficiency Rebates	Projects	-	-	-	-	-	-	-	-	-	-	-	-
29	LDC Custom Programs	Projects	-	-	-	-	-	-	-	-	-	-	-	-
Pre-2011 Programs completed in 2011 Total			**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Other														
30	Program Enabled Savings	Projects	-	-	-	-	-	-	-	-	-	-	-	-
31	Time-of-Use Savings	Homes	-	-	-	-	-	-	-	-	-	-	-	-
Other Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Adjustment to Previous Year's Verified Results														
Energy Efficiency Total							**40**	**29**	**21**	**22**	**231,397**	**136,081**	**108,265**	**136,321**
Demand Response Total (Scenario 1)							**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
OPA-Contracted LDC Portfolio Total							**40**	**29**	**21**	**22**	**231,397**	**136,081**	**108,265**	**136,321**

Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

***Includes adjustments after Final Reports were issued**

**** Updates to the previous quarter's participation may occur as a result of further data received**

Table 4A: Province-Wide Initiative and Program Level Savings by Year (Scenario 1)

#	Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Unverified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Unverified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
			2011 Adj.*	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program																
1	Appliance Retirement	Appliances	56,110	34,146	20,894		3,299	2,011	1,280		23,005,812	13,424,518	8,183,872		6,451	148,544,601
2	Appliance Exchange	Appliances	3,688	3,836	5,316		371	556	790		450,187	974,621	1,407,949		1,479	7,328,424
3	HVAC Incentives	Equipment	92,721	85,221	73,005		32,037	19,060	16,407		59,437,670	32,841,283	28,268,532		67,504	392,811,594
4	Conservation Instant Coupon Booklet	Measures	567,678	30,891	104,583		1,344	230	158		21,211,537	1,398,202	3,139,871		1,733	95,320,495
5	Bi-Annual Retailer Event	Measures	952,149	1,060,901	1,052,753		1,681	1,480	1,588		29,387,468	26,781,674	30,381,982		4,750	258,658,860
6	Retailer Co-op	Items	152	-	-		-	-	-		2,652	-	-		-	10,607
7	Residential Demand Response (switch/pstat)*	Devices	19,550	98,388	144,236		10,947	49,038	83,370		24,870	359,408	666,964		-	1,051,242
8	Residential Demand Response (IHD)	Devices	-	49,689	71,067		-	-	-		-	-	-		-	-
9	Residential New Construction	Homes	26	-	22		-	2	16		743	17,152	38,516		18	131,462
Consumer Program Total							**49,679**	**72,377**	**103,609**		**133,520,939**	**75,796,858**	**72,087,686**		**81,935**	**903,857,285**
Business Program																
10	Retrofit	Projects	2,819	5,605	7,737		24,467	61,147	54,775		136,002,258	314,922,468	334,817,664		138,792	2,150,282,786
11	Direct Install Lighting	Projects	20,741	18,494	16,159		23,724	15,284	16,352		61,076,701	57,345,798	67,108,291		47,532	525,289,451
12	Building Commissioning	Buildings	-	-	-		-	-	-		-	-	-		-	-
13	New Construction	Buildings	22	64	51		123	764	886		411,717	1,814,721	1,921,510		1,774	10,934,051
14	Energy Audit	Audits	196	280	189		-	1,450	978		-	7,049,351	4,758,312		2,428	30,664,678
15	Small Commercial Demand Response (switch/pstat)*	Devices	132	294	762		84	187	485		157	1,068	3,882		-	5,107
16	Small Commercial Demand Response (IHD)	Devices	-	-	138		-	-	-		-	-	-		-	-
17	Demand Response 3*	Facilities	145	151	175		16,218	19,389	25,054		633,421	281,823	364,174		-	1,279,418
Business Program Total							**64,616**	**98,221**	**98,530**		**198,124,254**	**381,415,229**	**408,973,833**		**190,526**	**2,718,455,491**
Industrial Program																
18	Process & System Upgrades	Projects	-	-	1		-	-	41		-	-	357,000		41	714,000
19	Monitoring & Targeting	Projects	-	-	-		-	-	-		-	-	-		-	-
20	Energy Manager	Projects	-	39	114		-	1,086	2,296		-	7,372,108	15,106,456		3,381	52,329,236
21	Retrofit	Projects	433	-	-		4,615	-	-		28,866,840	-	-		4,613	115,462,282
22	Demand Response 3*	Facilities	124	185	281		52,484	74,056	166,699		3,080,737	1,784,712	4,017,369		-	8,882,817
Industrial Program Total							**57,099**	**75,142**	**169,036**		**31,947,577**	**9,156,820**	**19,480,825**		**8,035**	**177,388,335**
Home Assistance Program																
23	Home Assistance Program	Homes	46	5,033	21,123		2	566	1,939		39,283	5,442,232	18,197,636		2,508	52,879,102
Home Assistance Program Total							**2**	**566**	**1,939**		**39,283**	**5,442,232**	**18,197,636**		**2,508**	**52,879,102**
Aboriginal Program																
24	Aboriginal Program	Homes	-	-	239		-	-	28		-	-	345,428		28	690,856
Aboriginal Program Total							**-**	**-**	**28**		**-**	**-**	**345,428**		**28**	**690,856**
Pre-2011 Programs completed in 2011																
24	Electricity Retrofit Incentive Program	Projects	2,028	-	-		21,662	-	-		121,138,219	-	-		21,662	484,552,876
25	High Performance New Construction	Projects	179	69	9		5,098	3,251	1,806		26,185,591	11,901,944	12,769,879		10,155	165,987,955
26	Toronto Comprehensive	Projects	577	-	-		15,805	-	-		86,964,886	-	-		15,805	347,859,545
27	Multifamily Energy Efficiency Rebates	Projects	110	-	-		1,981	-	-		7,595,683	-	-		1,981	30,382,733
28	LDC Custom Programs	Projects	8	-	-		399	-	-		1,367,170	-	-		399	5,468,679
Pre-2011 Programs completed in 2011 Total							**44,945**	**3,251**	**1,806**		**243,251,549**	**11,901,944**	**12,769,879**		**50,002**	**1,034,251,788**
Other																
29	Program Enabled Savings	Projects	-	-	-		-	2,304	-		-	1,188,362	-		2,304	3,565,086
30	Time-of-Use Savings	Homes	-	-	-		-	-	-		-	-	-		-	-
Other Total							**-**	**2,304**	**-**		**-**	**1,188,362**	**-**		**2,304**	**3,565,086**
Adjustment to Previous Year's Verified Results							**-**	**1,406**	**-**		**-**	**18,689,081**	**-**		**1,156**	**73,918,598**
Energy Efficiency Total							**136,608**	**109,191**	**99,340**		**603,144,417**	**482,474,434**	**526,802,898**		**335,338**	**4,879,869,359**
Demand Response Total (Scenario 1)							**79,733**	**142,670**	**275,608**		**3,739,185**	**2,427,011**	**5,052,389**		**-**	**11,218,584**
OPA-Contracted LDC Portfolio Total							**216,341**	**253,267**	**374,948**		**606,883,602**	**503,590,526**	**531,855,287**		**336,494**	**4,965,006,541**

Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item for 2012 & 2013 will be left blank until the savings are quantified in the 2013 evaluation.

	kW	kWh
Full OEB Target:	**1,330,000**	**6,000,000,000**
% of Full OEB Target Achieved to Date (Scenario 1):	**25%**	**83%**

Table 4B: Province-Wide Initiative and Program Level Savings by Quarter for Current Reporting Year**

#	Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
			Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2013	Q2 2013	Q3 2013	Q4 2013
Consumer Program														
1	Appliance Retirement	Appliances	4,372	5,381	6,244	4,897	262	331	385	302	1,726,524	2,098,963	2,440,621	1,917,764
2	Appliance Exchange	Appliances	-	-	4,298	1,018	-	-	638	151	-	-	1,138,331	269,619
3	HVAC Incentives	Equipment	14,992	22,871	22,173	12,969	3,708	4,722	4,736	3,241	6,694,244	7,780,630	7,936,273	5,857,386
4	Conservation Instant Coupon Booklet	Measures	66	5,953	25,895	72,669	1	13	44	100	2,732	209,810	851,896	2,075,434
5	Bi-Annual Retailer Event	Measures	10,184	494,302	6,428	541,839	14	796	14	765	258,174	14,096,046	166,241	15,861,521
6	Retailer Co-op	Items	-	-	-	-	-	-	-	-	-	-	-	-
7	Residential Demand Response (switch/pstat)*	Devices	114,389	125,077	139,363	144,236	66,199	72,321	80,568	83,370	529,591	578,565	644,548	666,964
8	Residential Demand Response (IHD)	Devices	21,052	25,463	18,613	5,939	-	-	-	-	-	-	-	-
9	Residential New Construction	Homes	5	1	5	11	-	-	14	1	816	623	28,008	9,068
Consumer Program Total							**70,184**	**78,183**	**86,399**	**87,930**	**9,212,081**	**24,764,637**	**13,205,918**	**26,657,756**
Business Program														
10	Retrofit	Projects	1,683	2,077	2,467	1,510	13,556	14,218	15,851	11,149	79,459,717	78,895,962	110,001,262	66,460,723
11	Direct Install Lighting	Projects	4,130	4,512	3,776	3,741	4,224	4,644	3,648	3,836	17,243,776	20,516,334	15,003,555	14,344,625
12	Building Commissioning	Buildings	-	-	-	-	-	-	-	-	-	-	-	-
13	New Construction	Buildings	19	18	13	1	309	237	330	10	961,072	538,485	392,547	29,406
14	Energy Audit	Audits	87	73	19	10	450	378	98	52	2,190,334	1,837,867	478,349	251,763
15	Small Commercial Demand Response (switch/pstat)*	Devices	250	271	531	762	159	173	339	485	1,272	1,385	2,711	3,882
16	Small Commercial Demand Response (IHD)	Devices	38	53	20	27	-	-	-	-	-	-	-	-
17	Demand Response 3*	Facilities	153	170	171	175	20,082	27,275	24,055	25,054	786,518	608,767	536,899	364,174
Business Program Total							**38,780**	**46,925**	**44,321**	**40,586**	**100,642,689**	**102,398,800**	**126,415,323**	**81,454,573**
Industrial Program														
18	Process & System Upgrades	Projects	1	-	-	-	41	-	-	-	357,000	-	-	-
19	Monitoring & Targeting	Projects	-	-	-	-	-	-	-	-	-	-	-	-
20	Energy Manager	Projects	54	19	28	13	853	434	657	352	6,729,303	2,886,570	2,904,907	2,585,676
21	Retrofit	Projects	-	-	-	-	-	-	-	-	-	-	-	-
22	Demand Response 3*	Facilities	210	270	281	281	78,121	106,583	149,404	166,699	4,585,608	2,392,785	3,354,125	4,017,369
Industrial Program Total							**79,015**	**107,017**	**150,061**	**167,051**	**11,671,911**	**5,279,355**	**6,259,032**	**6,603,045**
Home Assistance Program														
23	Home Assistance Program	Homes	11,410	969	4,166	4,578	964	161	495	320	9,813,257	1,597,567	3,796,765	2,990,047
Home Assistance Program Total			**-**	**-**	**-**	**-**	**964**	**161**	**495**	**320**	**9,813,257**	**1,597,567**	**3,796,765**	**2,990,047**
Aboriginal Program														
24	Aboriginal Program	Homes	-	-	-	239	-	-	-	28	-	-	-	345,428
Aboriginal Program Total							**-**	**-**	**-**	**28**	**-**	**-**	**-**	**345,428**
Pre-2011 Programs completed in 2011														
24	Electricity Retrofit Incentive Program	Projects	-	-	-	-	-	-	-	-	-	-	-	-
25	High Performance New Construction	Projects	4	-	5	-	731	-	1,075	-	5,563,680	-	7,206,199	-
26	Toronto Comprehensive	Projects	-	-	-	-	-	-	-	-	-	-	-	-
27	Multifamily Energy Efficiency Rebates	Projects	-	-	-	-	-	-	-	-	-	-	-	-
28	LDC Custom Programs	Projects	-	-	-	-	-	-	-	-	-	-	-	-
Pre-2011 Programs completed in 2011 Total			**-**	**-**	**-**	**-**	**731**	**-**	**1,075**	**-**	**5,563,680**	**-**	**7,206,199**	**-**
Other														
29	Program Enabled Savings	Projects	-	-	-	-	-	-	-	-	-	-	-	-
30	Time-of-Use Savings	Homes	-	-	-	-	-	-	-	-	-	-	-	-
Other Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Adjustment to Previous Year's Verified Results														
Energy Efficiency Total							**25,113**	**25,934**	**27,985**	**20,307**	**131,000,629**	**130,458,857**	**152,344,954**	**112,998,460**
Demand Response Total (Scenario 1)							**164,561**	**206,352**	**254,366**	**275,608**	**5,902,989**	**3,581,502**	**4,538,283**	**5,052,389**
OPA-Contracted LDC Portfolio Total							**189,674**	**232,286**	**282,351**	**295,915**	**136,903,618**	**134,040,359**	**156,883,237**	**118,050,849**

Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

***Includes adjustments after Final Reports were issued**

**** Updates to the previous quarter's participation may occur as a result of additional data received**

Table 5: Data Qualifiers for Initiatives Currently In-Market & Likelihood of Additional Data

Data included in the Q4 2013 report includes all program activity completed (as per the savings 'start' date) on or before December 31st, 2013.

Initiative	Savings 'start' Date	Data Available	Additional Data Likely
Consumer Program			
Appliance Retirement	Pick-up date	When database is queried. Typically up-to-date.	Moderate
Appliance Exchange	Exchange event date	Once data is submitted to the OPA by retailers and undergoes QA/QC by OPA staff. Typically 3 - 6 months to receive and process all data.	High
HVAC Incentives	Installation date1	Rebate Status = Approved, Cheque Issued and Cheque Cashed; Typically 1 - 4 months delay.	High
Conservation Instant Coupon Booklet	Coupon redemption year	Once data is submitted to the OPA by retailers and undergoes QA/QC by OPA staff. Typically 3 - 6 months to receive and process all data.	High
Bi-Annual Retailer Event	Year and quarter of the event		High
Retailer co-op activities	Will vary by specific project	Will vary by specific project	Low
Residential Demand Response	Device installation date	Data successfully uploaded into RDR settlement system as of December 31st, 2013	High
Residential New Construction	Project completion	Preliminary Billing Report submitted to OPA	Low
Business (Commercial & Institutional) Program			
Retrofit	Actual project completion date	In the "Post Project Submission" Stage (excluding "Payment Denied by LDC") within iCON CRM as of January 13th, 2013	Low
Direct Installed Lighting	Retrofit date	Work-order: invoiced, approved and paid to LDC. Typically 1.5 - 2 months delay. Any projects that are flagged as duplicates will not appear in reports until duplicates have been resolved.	High
Building Commissioning	Hand off date	Preliminary Billing Report submitted to OPA and reviewed	Moderate
New Construction	Actual project completion date	Preliminary Billing Report submitted to OPA and reviewed	Moderate
Energy Audit	Audit completion date	Preliminary Billing Report submitted to OPA and reviewed	Moderate
Small Commercial Demand Response	Device installation date	Data successfully uploaded into RDR settlement system	Moderate
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator	Low
Industrial Program			
Process & System Upgrades	In-service date	Preliminary Billing Report submitted to OPA and reviewed	Low
Monitoring & Targeting	Project completion date	Preliminary Billing Report submitted to OPA and reviewed	Low
Energy Manager (EEM or REM)	Project completion date	Completed, non-incented projects submitted quarterly by Energy Manager.	High
Retrofit	All Retrofit projects are now reported under the Business Program		
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator.	Low
Home Assistance Program			
Home Assistance Program	Project completion date	Preliminary Billing Report submitted to OPA and reviewed	High
Pre-2011 Projects Completed in 2011			
High Performance New Construction	Project completion date	Reviewed and processed from delivery agent, quarterly	Moderate

1: Monthly reports split savings into months using the approval date

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years). Annual savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011.

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

Current Reporting Period: the calendar quarter specified on page 1 of this report.

Effective Useful Life: detemines the persistence of savings for a given technology or initiative. Factors that may effect the useful life of a technology are typical use and operating hours, upcoming code changes, etc. Demand response resources are assumed to have a persistence of 1 year.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses). All savings presented in this report are at the end-user level.

Final or Verified Savings: savings achieved that have undergone annual Evaluation, Measurement & Verification (EM&V) and thus have had activity audited and savings assumptions measured and verified.

Implementation Period: the particular calendar quarter or calendar year that conservation activity is achieved based on when the savings are considered to 'start' (please see table 5).

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5). Incremental savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011 (i.e. Incremental = Annual for demand response only).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Program-to-Date: the reporting period from January 1, 2011 until the end of the Current Reporting Period.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Reported or Unverified Savings: savings achieved that are based on reported activity and forecasted or best available savings assumptions. These savings are not verified, i.e. have not undergone the Evaluation, Measurement & Verification processes.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Reporting Methodology (Quarterly, Unverified results):

There are several resources on reporting that are available to LDCs:

- Reporting Policy & FAQ Document found on the iCON Portal in the "Other Program Materials" under "Reporting Tools"
- LDC Consumer Program Tracking Tool found on the iCON Portal in "Other Program Materials" under "Reporting Tools"
- Webinars (available at the following link: http://www.snwebcastcenter.com/custom_events/opa-20111781/site/index.php)
  - Understanding your Q4 2011 Report (April 11, 2012)
  - Tools from the Reporting WG (April 25, 2012)
  - A Deeper Look at: peaksaverPLUS® (May 23, 2012)
  - A Deeper Look at: Demand Response 3 (June 6, 2012)
  - Revisiting Reporting (June 20, 2012)
  - Quarterly CDM Status Report update (October 24, 2012) http://powerauthority.webex.com; password: DCx2012

3.0 –VECC -17

Reference: E3/T4/S1/pg.1

a) Why are there no revenues forecast for accounts 4082 and 4084 for either 2014 or 2015?
b) Please explain the higher than normal level of Rent from Electric Property (Acct. 4210) for 2012.
c) Please explain the Regulatory Debits (Acct. 4305) shown for 2013 and 2014.
d) Please explain the positive $94,130 value for Interest and Dividend Income in 2013 and why the values for 2014 and 2015 are materially lower than those for 2011 and 2013.
e) Where are the revenues from MicroFit charges included and how much are they for each of 2012-2015?

RESPONSE:

a) See response to 3-Energy Probe-19b.

b) See response to 3-Energy Probe-19c.

c) The Regulatory Debits, account 4305, are a result of the accounting policy change. See Exhibit 3, Tab 4, Schedule 3, page 1 and Exhibit 9, Tab 4, Schedule 3, Appendix 2-EE.

d) The variance in this account is related to the reversal of smart meter interest offset by interest on Deferral and Variance Accounts. See Exhibit 3, Tab 4, Schedule 3, page 1. See 3-Energy Probe-19h.

e) See response to 3-Energy Probe-19i.

(page left blank intentionally)

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.

RESPONSE:

a) & b)

For the 2015 OM&A forecast, API has used a 3 per cent inflationary factor for employee compensation based on the HayGroup letter (Exhibit 4, Tab 4, Schedule 1, Appendix C) and the collective agreement for 2015 (Exhibit 4, Tab 4, Schedule 1, page 6, lines 29-30). Non-labour amounts are generally forecasted using a 2 per cent inflationary rate. API has set this rate based on the Bank of Canada's monetary policy[1] aimed at keeping inflation at 2 per cent.

[1]http://www.bankofcanada.ca/rates/indicators/key-variables/inflation-control-target/

(page left blank intentionally)

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)[1]
- Ref: Report of the Board - Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (EB-2010-0379)[2]

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.

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.

---

[1] http://www.ontarioenergyboard.ca/oeb/_Documents/2013EDR/Board_ltr_LDC_2013_IRM3_Stretch_Factor_20121128.pdf

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

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.

RESPONSE:

a) As discussed in Exhibit 1, Tab 3, Schedule 1, API promotes open dialogue and seeks customers' feedback and experiences to shape its business direction where practical and with regard to its long-term strategy of improving reliability, service quality and capacity. API's customer engagement has highlighted the importance of maintaining reliability, responding to outages in a timely fashion and, seeks to understand customer expectations.

Accordingly, API has focused its OM&A program on maintaining and improving service levels.

As discussed in Exhibit 1, Tab 2, Schedule 6, API OM&A cost increases are related to 3 major areas

i) Vegetation Management and SCADA
ii) GEC (accounting changes)
iii) and other impacts

As shown in Exhibit 1, Tab 2, Schedule 6, Table 1.2.6.2, adjusting for the Forestry & SCADA plus GEC to isolate the other impacts results in a 2.8% (per year) adjustment.

With respect to above noted programs which have resulted in the largest impacts to the OM&A, API describes these impacts with the engagement activities that have supported these increases as highlighted below:

Vegetation Management

The Vegetation Management program represents approximately 25% of the OM&A budget of API. This program is designed to maintain Right-of-Way ("ROW") clearances in order to ensure that public safety, employee safety and reliability are maintained or improved as required. The increase proposed in this Application is requested specifically to ensure that current service levels can be maintained. The increased scope is directly related to the increase in total ROW area that resulted from the ROW expansion project which was completed over the past few years. This program and scope increase is fully described in Exhibit 4, Tab 1, Schedule 1, Appendix A. API has had direct feedback from its customers though the following engagements that support this program:

i. <u>Annual customer satisfaction survey (as described in Exhibit 1, Tab 3, Schedule 1)</u> - customers have rated reliable and safe delivery of electricity as a high expectation

ii. <u>Annual stakeholder meetings (as described in Exhibit 1, Tab 3, Schedule 1)</u> – municipalities have reinforced the importance the ROW expansion program has had over the past number of years with a positive result and increased reliability. API should maintain this increased reliability.

iii. Customer Information Sessions – specific meetings in regard to upcoming projects were held in the past. Overall, community members noticed an improvement in reliability over the years, appreciated our efforts and work and understood why we were returning with the specific project vegetation management work.

iv. Customer Notifications – during the planning phase of the vegetation management annual scope, customers and land owners that have some effect from line clearing operations are individually notified. That notification engagement often includes discussions about API's vegetation management program and its results. While not all customers can agree that some trees will need to be removed from the established ROW on their property, API has received very positive comments in regards to the reliability improvements of the API electricity service.

SCADA and Dispatch

API does not have an automated SCADA system or a dedicated control room. With the expectation of implementing new smart grid technology for improving reliability, as well as decreasing the costs and response time related to planned and unplanned outages, API is proposing the implementation of this functionality in 2015. API has described its SCADA program and scope increases in Exhibit 4, Tab 1, Schedule 1, Appendix B. While API did not get direct feedback regarding this smart grid initiative, it is widely understood that LDC's will benefit customers through the use of smart grid technologies. API is likely one of the few LDC's that does not have a SCADA system and control room. This initiative will bring API closer to industry norms and will be able to increase service levels as a result. General feedback that is supportive of this program can be summarized as follows:

i) Annual customer satisfaction survey (as described in Exhibit 1, Tab 3, Schedule 1) - customers have rated reliable and safe delivery of electricity as a high expectation. Also, there is an expectation that API provide more timely information during power outages.

General Expense Capital (GEC)

The second impact relates to the change in accounting policies resulting in the elimination of the capitalized overhead. 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. The accounting policy changes account for approximately $1.1 million of cost now attributable to OM&A and represents approximately 1/3 of the variance between the 2015 Test Year compared to the 2011 Actual.

API did not consider this impact in its engagements with customers as this is a rule driven change.

Other variances

The remaining 1/3 variance of; the total variance between the 2015 Test Year compared to the 2011 Actual, is related to a variety of smaller operational adjustments and inflationary pressures. These are described more fully in Exhibit 4, Tab 3, Schedule 1, and represent the 2.8% (per year) normalized OM&A increases since 2011. As noted in Exhibit 1, Tab 3, Schedule 1, API discusses topics related to many aspects of annual OM&A and capital programs with customers and stakeholders in order to meet expectations.

b) As discussed in a) above, API customers value API's system reliability. Survey results have rated API at 92% (good/excellent) service. API has concluded that through its' vegetation management plan Exhibit 4, Schedule 1, Tab 1, Appendix A, that reliability will suffer if API does not increase the scope and spending as proposed in this application. Direct feedback from customers as noted in answer a) above have provided positive support for the improvements to reliability API has made with the ROW widening project which was approved in EB-2007-0744. API has utilized this feedback in its assumption that customers would not want to see a decrease in API reliability, which would occur should the increased Vegetation Management costs not be approved in this application.

c) API has studied its Vegetation Management program against a standard using a national expert in Vegetation Management as described in Exhibit 4, Schedule 1, Tab 1, Appendix A. API has utilized a SCADA 3rd party expert in preparing a business case for SCADA within API system as described in Exhibit 4, Schedule 1, Tab1, Appendix B. API participates in a number of programs that relate directly to API operational and capital programs to ensure a "best practice" approach. Examples include – USF (Utilities Standards Forum), EDA Northeast buying group, and through its costs sharing amongst its FortisOntario group of companies.

d) Please refer to Section 5.3.3 of API's Distribution System Plan at Exhibit 2, Tab 3, Schedule 1, for a thorough discussion on API's asset optimization policies and practices by asset type. An example of this would be the hazard tree removal capital program proposed that will achieve an increased reliability, lower outage response costs and sustainable vegetation management costs in the long run. More details on this program can be found in Exhibit 2, Tab 3, Schedule 1, Appendix C.

e) In its decision EB-2013-0110, the board said, "the Board finds that assigning Algoma to the highest stretch factor of 0.6% would not be appropriate as the PEG model was designed to benchmark the whole distribution sector. Algoma has consistently argued that the PEG model does not fit its circumstances". The decision goes on to state that API is welcome to propose some other form of rate making for its 2015 Incentive Rates for its next IR application. As described in this application, API continues to seek ways to efficiently deliver service in the challenging , rural and low density service area it services while balancing the needs of its customers as discussed in answers a) through d) above.

f) As discussed in answers a) through d) above, API expects positive service level outcomes in a number of program areas including the following areas:

   a. SCADA – improved reliability, lower costs
   b. Vegetation Management – maintained reliability as a result of managing the impact and number of vegetation related outages

(page left blank intentionally)

22. 4Staff22 – 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.

RESPONSE:

a) The increase in API costs for General and Administrative from 2012 to 2013 is primarily a result of the change in capitalization policy effective January 1, 2013, consistent with the Board's regulatory accounting policy direction in the Board letter of July 17, 2012. See Exhibit 4, Tab 2, Schedule 2, Appendix 2-JB; overheads no longer capitalized of $1,142,000. This accounts for 39% of the 44% increase. The remaining 5% or $166,678 would include administrative time that was capitalized for the SAP/CIS implementation in 2012, normal salary increases in 2013 and other miscellaneous items.

(page left blank intentionally)

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?

RESPONSE:

a)

i. Please see API's response to 4-EP-21. Outage response costs are based on historical averages and trends of actual response costs. API has concluded customers would like more timely information during power outages, from its annual customer satisfaction survey and stakeholder meetings. API is working towards the implementation of an Outage Management System (OMS) in order to be able to provide an improved level of service in this category.

ii. The increase in general administrative is primarily as result of employee compensation and the allocation of shared services. See responses to 4-Staff-24, 4-VECC-22 and 4-VECC-25. As noted in evidence, within the FortisOntario organization, staff, systems and certain facilities are shared to maximize efficiencies of scale, avoid duplication, and provide the required skills and expertise to each business function. Examples of these shared functions are executive management, administrative support functions (finance, human resources, health, safety and environment and information technology) and asset management. These activities support and provide benefits to all of FortisOntario's regulated business units. Where permitted by considerations of location, customer service, engineering and operations staff, systems and equipment are also shared. The costs are shared by the business units based on allocation.

iii. VM – The reasons for the forecast increase in cost is the wider rights of way that must now be maintained following completion of the ROW Expansion Program. The business decision was based on the results of the 3rd party study "Performance Management Review and Quantification of Vegetation Management Work, Risks & Resource Requirements" included at Appendix E of API's Distribution System Plan (Exhibit 2, Tab 3, Schedule 1, Appendix A). The value for customers is that the resulting vegetation management program has been designed in a least cost sustainable manner. Any underfunding of this program would result in a compounding increase of future costs required to achieve the same result. Should API not receive the requested funding increases, reliability service levels will drop according to the above noted study. API has received feedback from customers in the annual satisfaction survey and through annual community meetings that indicate satisfaction with the current level of reliability. API's increased funding seeks to achieve the balance between customer expectations and efficient expenditure.

iv. SCADA – The costs are related implementing control room functionality in 2015. The business decision that led to this program was based on the results of the "SCADA System Business Case for Algoma Power Inc." provided in response to 4-VECC-20. The business case was based on a thorough analysis of costs and benefits, including reliability benefits to API's customers. API has received feedback from customers in the annual satisfaction survey that indicates satisfaction with the current level of reliability. This program is designed to increase reliability and decrease operational costs in the long run.

b) API expects efficiencies in the unit costs associated with its vegetation management program as a result of fewer reactive responses to hazard trees, as well as progress on the most efficient cycle lengths identified for each of the vegetation management activities. API also expects that the annual cost increases associated with SCADA and the use of a control room will be largely offset by changes to business processes and operational activities as described and quantified in Exhibit 4, Tab 1, Schedule 1, Appendix B, p. 11-12.

c) The projected costs for 2015 are expected to be mainly recurring, with a longer term expectation of reduction of outage response costs following significant penetration of SCADA-capable devices. The capital hazard tree removal program would reduce outage response costs in the long run as well. The general administrative costs are expected to remain recurring.

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)[1]
- Ref: OEB - 2012 Yearbook[2] 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.

RESPONSE:

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

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

a) As described in 4Staff21, API has described fully what additional value the customers will receive for the increase in OM&A. The OM&A can be expressed on a per FTE basis

b) As described in 4Staff21, API has been working to ensure that OM&A costs are reduced in the long term.

c) As API has explained in the application Exhibit 2, Tab3, Schedule 1, the low population density and large service area creates a high cost per customer.

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 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".

RESPONSE:

a) API confirms that the "On-Going" label was an oversight and should have been labeled as "One-Time" as the $15,000 reflects one fifth of the $75,000 Intervenor Costs provided in the lower section of Table 4.8.1.1 which shows the 2015 cost-of-service application costs.

b) Not applicable. Please refer to response provided in 4Staff25 part a) above.

(page left blank intentionally)

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.

RESPONSE:

a) In order to establish objectives for its operations, API relies on the following inputs:

- The experience and operating knowledge of its employees
- The feedback from its customers through its various stakeholder communications forums
- Good utility practice from the perspective of customer service, reliability, power quality, safety and the environment
- Overall costs

Based on the foregoing, API objectives are to provide good customer service at a reasonable price. In the forecast period this includes an emphasis on reliability and system restoration; immediate responses to system requirements are:

- Attention to vegetation management with respect for environmental issues unique to the service area. API's service territory is vast and heavily forested; access is limited and customers are geographically dispersed. Therefore vegetation management is a prime concern for API and its customers because of its meaningful impact on customer service, reliability and power quality. Vegetation management is and must be a cornerstone of API operational objectives.
- Maintenance and sustainment of API's core distribution assets, poles and wires, are critical. Much of API's distribution system is remotely located and not accessible from roadways. Diligent maintenance and sustainment of these core distribution assets are an important component of API's operational objectives.
- The development of SCADA technology, which is the basic enabler of a smart grid, is a longer term solution to allow API to monitor the performance of its distribution system. Facilities in place to monitor and have supervisory control of distribution assets will allow API staff to better respond to reliability threats to the distribution system.

b) The very nature of the objectives identified for API requires it to provide the necessary human resources of respond to the needs of its customers and the development of the distribution system.

Where applicable, API has strived to find prudent and sustainable solutions to meet its objectives. API has utilized expert third party opinion to develop an effective and sustainable vegetation plan. As well, API has sought third party advice on a means to effectively deploy SCADA in a vast and remote service area by leveraging existing distribution assets.

API works diligently with local stakeholders including municipal governments, First Nations communities, land holders and railways to ensure access to its remotely located distribution assets. These land use arrangements allow access and reduces cost associated with maintenance and sustainment of the assets.

This planning and establishment of objectives have served to allow API to manage and balance its targeted capital and operational expenditures with human resource planning.

(page left blank intentionally)

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[1] (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?

RESPONSE:

a) API agrees that the LEAP amounts should be closer to $28,211 as calculated by Board Staff. However, the calculation of the LEAP funding is a direct function of API's revenue requirement, which had been calculated for this application based on costs including the LEAP funding. Given the iterative cycle, API proposes that once the Board has determined the revenue requirement for API, the new LEAP amounts would be estimated and included in the calculation of the draft rate order.

b) There is an increase in the overall bad debt expense. However, API does not see reason to adjust LEAP funding beyond what the board guideline suggests.

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

(page left blank intentionally)

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.

RESPONSE:

a) The amount of depreciation in the tax calculations does not include the depreciation expense on the corporate asset allocations. The CCA schedule also does not include any amounts for the corporate asset allocations.

The depreciation expense on the corporate asset allocations is included in the RRWF and Appendix 2-CU due to the fact that they are shared assets. Please refer to Exhibit 4, Tab 5, Schedule 1, for a more detailed discussion on shared assets.

(page left blank intentionally)

<u>4-Energy Probe-20</u>

Ref: Exhibit 4, Tab 1, Schedule 1

a) Please confirm that all the figures shown in Table 4.1.1.1 are on an ASPE accounting basis. If this is not the case, please explain which years are on an ASPE basis and which are on a CGAAP basis.

b) Do the figures included in Table 4.1.1.1 include the property taxes shown in Exhibit 4, Tab 2, Schedule 5?

c) Please explain what GEC stands for in Table 4.1.1.2.

d) If the GEC line reflects the accounting adjustment made effective January 1, 2013, does this mean that the actual OM&A costs shown for the 2011 Board approved and actual 2011 and 2012 columns were higher by the amounts shown in the GEC line if they were shown on a comparable basis to the 2013 through 2015 figures? If not, please explain fully the adjustments made in the GEC line.

e) Please provide the most recent year-to-date actuals for 2014 in the same level of detail as found in Table 4.1.1.1 and the figures for the corresponding period in 2013.

RESPONSE:

a) The figures shown in Table 4.1.1.1 are on an ASPE accounting basis.

b) The figures in Table 4.1.1.1 include the property taxes shown in Exhibit 4, Tab 2, Schedule 5.

c) GEC stands for General Expense Capital. It is the administrative expenses that are capitalized.

d) The General Administration costs are comparable for the 2011 to 2015 years before the deduction of the GEC (see Table 4.1.1.2). The GEC is no longer capitalized in 2013 to 2015 due to the change in accounting policy.

e) The June 30 year-to-date actuals for 2013 and 2014 are shown below.

Summary of Operating Costs Table 4.1.1.1		
Description	**2013 Actual YTD June 30**	**2014 Actual YTD June 30**
Operating	838,875	835,994
Maintenance (1)	1,677,216	1,324,535
Billing and Collection	470,665	494,333
Community Relations	9,239	12,936
Administrative and General	2,062,929	2,125,462
Total	5,058,924	4,793,260

(1) Due to the harsher winter conditions in 2014 less was spent on vegetation management on a year-to-date basis compared to 2013.

4-Energy Probe-21

Ref: Exhibit 4, Tab 2, Schedule 2

a) **Please explain why the outage response costs are forecast to decline by $90,000 in 2014 and then increase by $180,000 in 2015.**

b) **Please confirm that API now bills all customers on a monthly basis, whereas before the Residential - R2 class was billed monthly, the Residential R1 class was billed bi-monthly, the street lighting class was billed monthly and the Seasonal class was billed annually. If this is not correct, please indicate the billing frequency for each rate class prior to and after the change in billing frequency.**

RESPONSE:

a) Outage response costs are influenced by long term system capital and vegetation maintenance improvements in conjunction with short term (annual) weather impacts. Both of these influences are difficult to predict actual outcomes with respect to the annual forecasted outage response expenses. API reviews past spending in this category and then determines based on review of both average and trend what the appropriate level should be for the forecast. Forecasts had been lowered for the 2014 budget year based on a perceived downward trend, however, actual spending in 2013 due to spring and fall weather events had increased actual spending in 2013 and increased averages and reversed the downward trend. API increased its forecast in 2015 to reflect the above noted review. It is expected that as the vegetation management program is fully implemented and the SCADA system is installed, that long term outage response costs ought to trend downward.

b) The previous billing frequency noted in the question is correct.

(page left blank intentionally)

<u>4-Energy Probe-22</u>

Ref: Exhibit 4, Tab 4, Schedule 1

a) **What was the wage increase for unionized employees in 2010, 2011 and 2012?**

b) **What is the impact on the 2015 revenue requirement if the unionized wage increases for January 1, 2014 and January 1, 2015 were both 2.0%?**

c) **Please provide the annual percentage change in the Labour AWE - All Employees - Ontario from Statistics Canada that the Board used to calculate the 2014 inflation factor value in the EB-2010-0379 Report of the Board dated November 21, 2013.**

d) **What was the annual increase for executive, management and non-union staff in each of 2010 through 2013 and what is the forecast for 2014 and 2015?**

RESPONSE:

a) January 1, 2010 = 1%
July 1, 2010 = 2%
January 1, 2011 = 2.75%
January 1, 2012 = 3%

b) The impact on the 2015 revenue requirement if the unionized wage increases for January 1, 2014 and January 1, 2015 were both 2.0% is approximately a $35,000 reduction. API based this assumption on the collective agreement with Power Workers Union using negotiated rates of 2.9% January 1, 2014, 3% January 1, 2015, and 3.1% January 1, 2016. API believes that its inflation assumption is reasonable and is supported.

c) Per Appendix C of the EB-2010-0379 Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, original issue dated November 21, 2013 and as corrected December 4, 2013, 1.5% was the annual percentage change in labour AWE – All Employees - Ontario from Statistics Canada used in calculating the annual index for rates effective in 2014.

d) The average annual increase in salaries for executive, management and non-union staff are as follows:

Summary - Average Annual Increases	2011*	2012	2013	2014	2015
Executive, Management and Non-Union	3.47%	4.66%	4.61%	4.18%	3.00%

***No shared service employees included in 2011 only**

These increases are a combination of inflation, step increases within the HayGroup performance rating system, and market adjustments.

As noted in Exhibit 4, Tab 4, Schedule 1, API uses a reference community of participants in the Hay Compensation Comparison. API uses this reference community to establish the market rates for similar positions in Ontario. To attract and retain qualified staff, the Company sets midpoint salaries using a policy line recommended by HayGroup management consultants. Actual salaries are set by reference to these recommendations and to corporate and individual performance.

4-Energy Probe-23

Ref: Exhibit 4, Tab 4, Schedule 1, Appendix A

What is the current level of FTE's for 2014?

RESPONSE:

The current level of FTE’s for 2014 is 77.28. API plans to backfill the 3.24 FTEs with a lineman and seasonal Forestry workers.

(page left blank intentionally)

4-Energy Probe-24

Ref: Exhibit 4, Tab 4, Schedule 1

Please provide a table that shows for each of 2011 through 2015 the actual/forecast amount of incentive compensation, the total potential compensation that was/will be available and the ratio of the amount paid/forecast to be paid to the potential.

RESPONSE:

INCENTIVE COMPENSATION

	2011	2012	2013	2014 Bridge	2015 Test
Actual/Forecast Incentive Pay	$290 340	$316 185	$312 792	$362 684*	$356 284*
Total Budgeted Incentive	$250 531	$259 881	$266 992	$362 684	$356 284
Ratio Paid to Forecast	**115.9%**	**121.7%**	**117.2%**	**100%**	**100%**

The variance from 2014 and 2015 budgeted to 2013 budgeted can be explained by the fact that 2014 and 2015 budgeted amounts were based on prior years actual payouts as well as increased shared services allocations.

*For revenue requirement purposes, API is forecasting 100% payout.

(page left blank intentionally)

4-Energy Probe-25

Ref: Exhibit 4, Tab 11, Schedule 1

The evidence indicates that API calculates amortization commencing in the month following the month the asset is capitalized for capital additions during the current year. Please provide the actual amortization expense for capital additions during the current year for each of 2011 through 2013 and the amount that would have been calculated if the half year rule had been used for those years.

RESPONSE:

The actual amortization expense for capital additions during the current year for each of 2011 through 2013 and the amount that would have been calculated if the half year rule had been used for those years is shown below.

Amortization Expense on Yearly Additions		
Year	Actual	Half Year Rule
2011	$ 233,739	$ 293,051
2012	$ 266,306	$ 295,436
2013 - with accounting policy change	$ 241,701	$ 296,546

(page left blank intentionally)

<u>4-Energy Probe-26</u>

Ref: Exhibit 4, Tab 11, Schedule 2

a) **Please explain how the depreciation on asset allocations is calculated.**

b) **Does API capitalize and/or expense any of the depreciation expense for such things as transportation equipment? If yes, please quantify the amount in each of 2011 through 2015.**

RESPONSE:

a) The depreciation on the corporate allocations is calculated as the difference between the opening and closing accumulated depreciation balances. See response to 2-Energy Probe-4d.

The exception is the 2012 amount because it was the first full year that SAP was implemented at API. It was calculated as the percentage allocation rate of 32.1% times the annual corporate depreciation expense for computer hardware and software of $820,862.

b) API does capitalize depreciation on transportation equipment. The depreciation is built into the labour rates and the approximate amounts capitalized are as follows.

	2011	2012	2013	2014	2015
Vehicle depreciation capitalized	$ 130,735	$ 153,244	$ 103,315	$ 110,441	$ 98,590

(page left blank intentionally)

<u>4-Energy Probe-27</u>

Ref: Exhibit 4, Tab 12, Schedule 3 &
Exhibit 2, Tab 1, Schedule 3

Please explain the significant differences in CCA additions ($5,536,393) and gross asset additions ($9,940,474) for 2013.

RESPONSE:

The difference between the 2013 CCA additions of $5,536,393 and the 2013 gross asset additions of $9,940,474 is a result of smart meters being added to CCA as they were installed. In 2013 the smart meter assets of $4,378,452 were moved from the regulatory accounts into the fixed assets.

(page left blank intentionally)

4-Energy Probe-28

Ref: Exhibit 4, Tab 12, Schedule 4

Please provide a copy of the 2013 income tax return.

RESPONSE:

Attached is a copy of the 2013 income tax return.

(page left blank intentionally)

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) **001** 82249 4290 RC0001

Corporation's name
002 Algoma Power Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . **010** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 2 Sackville Road
012

City	Province, territory, or state
015 Sault Ste Marie	**016** ON
Country (other than Canada) **017**	Postal code/Zip code **018** P6B 6J6

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . **020** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o FortisOntario
022 1130 Bertie Street
023 PO Box 1218

City	Province, territory, or state
025 Fort Erie	**026** ON
Country (other than Canada) **027**	Postal code/Zip code **028** L2A 5Y2

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . **030** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 1130 Bertie Street
032 PO Box 1218

City	Province,territory, or state
035 Fort Erie	**036** ON
Country (other than Canada) **037** CA	Postal code/Zip code **038** L2A 5Y2

040 Type of corporation at the end of the tax year
1 [ ] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [X] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . **043** ______ YYYY MM DD

To which tax year does this return apply?
Tax year start **060** 2013-01-01 (YYYY MM DD)
Tax year-end **061** 2013-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . **063** 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired . . . . **065** ______ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:
subparagraph 88(2)(a)(iv)? . . . . **064** 1 Yes [ ] 2 No [X]
subsection 249(3.1)? . . . . **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . **070** 1 Yes [ ] 2 No [X]
Amalgamation? . . . . **071** 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . **078** 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used . . . . **079** ______

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081 ______

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area
095 **096**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134
Did the corporation have any controlled foreign affiliates?	258		T1134
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

	Line	1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

			%
284	Electricity	285	100.000 %
286		287	%
288		289	%

	Line	1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ________ YYYY MM DD

	Line	1 Yes	2 No
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295		

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		791,458	A
Deduct: Charitable donations from Schedule 2	311	36,369		
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		36,369 ►	36,369	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			755,089	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		755,089	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			755,089	Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 4 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . **410** ______ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x **415** ***** ______ D / 11,250 = ... ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . **425** ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = ... **430** ______ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*				A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			B	
Amount QQ from Part 13 of Schedule 27			C	
Personal service business income**	432		D	
Amount used to calculate the credit union deduction (amount F from Schedule 17)			E	
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			F	
Aggregate investment income from line 440 on page 6***			G	
Total of amounts B to G			▶	H
Amount A **minus** amount H (if negative, enter "0")				I

Amount I		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x 11.5 % =		J
Amount I		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365 / 365	x 13 % =		K

General tax reduction for Canadian-controlled private corporations – Amount J **plus** amount K L
Enter amount L on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.
** For tax years beginning after October 31, 2011.
*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				755,089	M
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			N		
Amount QQ from Part 13 of Schedule 27			O		
Personal service business income*	434		P		
Amount used to calculate the credit union deduction (amount F from Schedule 17)			Q		
Total of amounts N to Q			▶		R
Amount M **minus** amount R (if negative, enter "0")				755,089	S

Amount S	755,089	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x 11.5 % =		T
Amount S	755,089	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365 / 365	x 13 % =	98,162	U

General tax reduction – Amount T **plus** amount U .... 98,162 V
Enter amount V on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ________ x 26 2 / 3 % = ... ________ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ________ B

Deduct:
Foreign investment income from Schedule 7 . . . . **445** ________ x 9 1 / 3 % = ________ C
(if negative, enter "0") ________ ▶ ________ D

Amount A **minus** amount D (if negative, enter "0") . . . . ________ E

Taxable income from line 360 on page 3 . . . . ________ F

Deduct:
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ________ G

Foreign non-business income tax credit from line 632 on page 7 . . . ________ x 25/9* 100 / 35 = ________ H

Foreign business income tax credit from line 636 on page 7 . . . . ________ x 1(0.38 - X**) / 4 = ________ I

Subtotal ________ ▶ ________ J

________ K

x 26 2 / 3 % = ________ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . ________ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** ________ N

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ________

Deduct: Dividend refund for the previous tax year . . . . **465** ________

________ ▶ ________ O

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ________ P

Total Part IV tax payable from Schedule 3 . . . . ________ Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ________

________ ▶ ________ R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R . . . . **485** ________

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . ________ x 1 / 3 = ________ S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ________ T

Dividend refund – Amount S or T, whichever is less (enter this amount on line 784 on page 8) . . . . ________

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %			550	286,934 A
Recapture of investment tax credit from Schedule 31			602	B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3			
Deduct: Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount		▶	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** amounts A to C)		286,934	D

Deduct:

Small business deduction from line 430 on page 4			1	
Federal tax abatement	608	75,509		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
Taxed capital gains 624				
Additional deduction – credit unions from Schedule 17	628			
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
General tax reduction for CCPCs from amount L on page 5	638			
General tax reduction from amount V on page 5	639	98,162		
Federal logging tax credit from Schedule 21	640			
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652	6,000		
Subtotal		179,671	▶	179,671 E

Part I tax payable – Amount D **minus** amount E	107,263 F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	107,263
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		107,263

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	57,678	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
(The Nova Scotia tax on large corporations is eliminated effective July 1, 2012.) Total provincial tax		57,678 ▶	57,678
Total tax payable	770		164,941 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	350,000	
Total credits	890	350,000 ▶	350,000 B

Refund code 894 1 Overpayment 185,059

Balance (amount A **minus** amount B) -185,059

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . .

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 ______ Branch number

914 ______ Institution number 918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☐

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920

Certification

I, 950 King | 951 Glen | 954 Chief Financial Officer,
Last name (print) | First name (print) | Position, office, or rank

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2014-06-23 Date (yyyy/mm/dd) | ______ Signature of the authorized signing officer of the corporation | 956 (905) 871-0330 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No X

958 Harry Clutterbuck Name (print) | 959 (905) 871-0330 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Schedule of Instalment Remittances

Name of corporation contact: Harry Clutterbuck
Telephone number: (905) 871-0330

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
2013-01-31	Federal Installment	20,000
2013-02-28	Federal Installment	20,000
2013-03-31	Federal Installment	20,000
2013-04-30	Federal Installment	20,000
2013-05-31	Federal Installment	30,000
2013-06-30	Federal Installment	30,000
2013-07-31	Federal Installment	30,000
2013-08-30	Federal Installment	30,000
2013-09-30	Federal Installment	30,000
2013-10-31	Federal Installment	60,000
2013-11-30	Federal Installment	60,000
2013-12-31	Federal Installment	

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 350,000 **A**

Total instalments credited to the taxation year per T9 350,000 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	10,327,012	14,266,389
	Total tangible capital assets	2008	+	125,441,050	115,230,260
	Total accumulated amortization of tangible capital assets	2009	–	55,317,514	52,611,046
	Total intangible capital assets	2178	+	22,757,116	22,321,674
	Total accumulated amortization of intangible capital assets	2179	–	3,917,408	3,174,111
	Total long-term assets	2589	+	5,125,676	5,417,991
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	104,415,932	101,451,157
	Liabilities				
	Total current liabilities	3139	+	4,979,090	5,335,787
	Total long-term liabilities	3450	+	57,753,115	56,888,583
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	62,732,205	62,224,370
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	41,683,727	39,226,787
	Total liabilities and shareholder equity	3640	=	104,415,932	101,451,157
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	-2,324,054	-4,780,994

***** Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	40,519,529	39,465,235
	Cost of sales	8518	–	29,432,929	26,783,796
	Gross profit/loss	8519	=	11,086,600	12,681,439
	Cost of sales	8518	+	29,432,929	26,783,796
	Total operating expenses	9367	+	7,453,667	9,112,701
	Total expenses (mandatory field)	9368	=	36,886,596	35,896,497
	Total revenue (mandatory field)	8299	+	39,772,456	39,572,780
	Total expenses (mandatory field)	9368	–	36,886,596	35,896,497
	Net non-farming income	9369	=	2,885,860	3,676,283
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	2,885,860	3,676,283
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	268,116	-249,114
	Future (deferred) income tax provision	9995	–	160,803	85,845
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	2,456,941	3,839,552

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes checklist

Corporation's name	Business number	Tax year-end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

	Line	1 Yes	2 No
Does the accountant have a professional designation?	095	X	
Is the accountant connected* with the corporation?	097		X

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

	Line	1 Yes	2 No
Has the accountant expressed a reservation?	099		X

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client)	1	
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	

	Line	1 Yes	2 No
Were notes to the financial statements prepared?	101	X	

If **yes**, complete lines 104 to 107 below:

	Line	1 Yes	2 No
Are subsequent events mentioned in the notes?	104		X
Is re-evaluation of asset information mentioned in the notes?	105		X
Is contingent liability information mentioned in the notes?	106	X	
Is information regarding commitments mentioned in the notes?	107	X	
Does the corporation have investments in joint venture(s) or partnership(s)?	108		X

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . 200 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . 255 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . 260 1 Yes [ ] 2 No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . 265 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			2,456,941	A
Add:				
Provision for income taxes – current	101	268,116		
Provision for income taxes – deferred	102	160,803		
Amortization of tangible assets	104	2,388,466		
Amortization of intangible assets	106	743,297		
Charitable donations and gifts from Schedule 2	112	19,543		
Non-deductible meals and entertainment expenses	121	27,982		
Reserves from financial statements – balance at the end of the year	126	3,064,095		
Subtotal of additions		6,672,302	6,672,302	
Other additions:				
Debt issue expense	208	16,632		
Miscellaneous other additions:				
600 Depreciation adjustment (smart meters) - booked to GL 9025	290	1,116,380		
601 Ontario Apprenticeship training tax credit	291	27,425		
602 Apprenticeship job creation tax credit	292	6,000		
604				
Total	294			
Subtotal of other additions	199	1,166,437	1,166,437	
Total additions	500	7,838,739	7,838,739	B
Amount A **plus** amount B			10,295,680	
Deduct:				
Gain on disposal of assets per financial statements	401	3,359		
Capital cost allowance from Schedule 8	403	6,320,225		
Cumulative eligible capital deduction from Schedule 10	405	606,805		
Reserves from financial statements – balance at the beginning of the year	414	2,474,039		
Subtotal of deductions		9,404,428	9,404,428	
Other deductions:				
Miscellaneous other deductions:				
703 Debt issue costs 99,794				
Total 99,794	393	99,794		
704				
Total	394			
Subtotal of other deductions	499	99,794	99,794	
Total deductions	510	9,504,222	9,504,222	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			791,458	

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

- For use by corporations to claim any of the following:
  - charitable donations to qualified donees;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the federal *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- The eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- A gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation - Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Wawa Winter Carnival	350
United Way of SSM	11,043
Alzheimer Society of SSM	200
Searchmont Festival Society	250
The Canadian FOP Network	100
Power of Pink Charity	200
Algoma University Foundation	4,000
Bruc Mines Agricultural Society	100
Business Improvement Association	100
Township of Johnson	100
Sault Area Hospital	2,500
Batchewana First Nation of Ojibways	200
St Joes Island Bicentennial & Canadian Diabeties	100
Van Daele Residents & Royal Canadian Legion	100
Algoma Highland Conservancy	200
Subtotal	19,543
Add: Total donations of less than $100 each	
Total donations in current tax year	19,543

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year		16,826	A	16,826	16,826
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the tax year	240	16,826	B	16,826	16,826
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1)	210	19,543		19,543	19,543
Subtotal (line 250 **plus** line 210)		19,543	C	19,543	19,543
Subtotal (amount B **plus** amount C)		36,369	D	36,369	36,369
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255				
Total charitable donations available (amount D **minus** amount on line 255)		36,369	E	36,369	36,369
Deduct: Amount applied against taxable income (cannot be more than amount O in Part 2) (enter this amount on line 311 of the T2 return)	260	36,369		36,369	36,369
Charitable donations closing balance (amount E **minus** amount on line 260)	280				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2012-12-31	16,826	16,826	16,826
2nd prior year	2011-12-31			
3rd prior year	2010-12-31			
4th prior year	2009-12-31			
5th prior year	2009-10-08			
6th prior year*				
7th prior year				
8th prior year				
9th prior year				
10th prior year				
11th prior year				
12th prior year				
13th prior year				
14th prior year				
15th prior year				
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total (to line A)		16,826	16,826	16,826

***** For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes * **multiplied** by 75 %			593,594	F
Taxable capital gains arising in respect of gifts of capital property included in Part 1 **	225	G		
Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01)	227	H		
The amount of the recapture of capital cost allowance in respect of charitable gifts	230			
Proceeds of disposition, less outlays and expenses **		I		
Capital cost **		J		
Amount I or J, whichever is less	235			
Amount on line 230 or 235, whichever is less		K		
Subtotal (**add** amounts G, H, and K)		L		
Amount L **multiplied** by 25 %				M
Subtotal (amount F **plus** amount M)			593,594	N
Maximum allowable deduction for charitable donations (enter amount E from Part 1, amount N, or net income for tax purposes, whichever is less)			36,369	O

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year			A
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339		
Gifts to Canada, a province, or a territory at the beginning of the tax year	340		B
Add:			
Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary	350		
Total current-year gifts made to Canada, a province, or a territory *	310		
Subtotal (line 350 **plus** line 310)		►	C
Subtotal (amount B **plus** amount C)			D
Deduct:			
Adjustment for an acquisition of control (for gifts made after March 22, 2004)	355		
Amount applied against taxable income (enter this amount on line 312 of the T2 return)	360		
Subtotal (line 355 **plus** line 360)		►	E
Gifts to Canada, a province, or a territory closing balance (amount D **minus** amount E)	380		

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			F		
Deduct: Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the tax year	440		G		
Add:					
Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450				
Total current-year gifts of certified cultural property	410				
Subtotal (line 450 **plus** line 410)			H		
Subtotal (amount G **plus** amount H)			I		
Deduct:					
Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455				
Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			J		
Gifts of certified cultural property closing balance (amount I **minus** amount J)	480				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2012-12-31			
2nd prior year	2011-12-31			
3rd prior year	2010-12-31			
4th prior year	2009-12-31			
5th prior year	2009-10-08			
6th prior year*				
7th prior year				
8th prior year				
9th prior year				
10th prior year				
11th prior year				
12th prior year				
13th prior year				
14th prior year				
15th prior year				
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

	Line	Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			K		
Deduct: Gifts of certified ecologically sensitive land expired after five tax years	539				
Gifts of certified ecologically sensitive land at the beginning of the tax year	540		L		
Add:					
Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land	510				
Subtotal (line 550 **plus** line 510)			M		
Subtotal (amount L **plus** amount M)			N		
Deduct:					
Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555				
Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			O		
Gifts of certified ecologically sensitive land closing balance (amount N **minus** amount O)	580				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Québec	Alberta
1st prior year	2012-12-31			
2nd prior year	2011-12-31			
3rd prior year	2010-12-31			
4th prior year	2009-12-31			
5th prior year	2009-10-08			
6th prior year*				
7th prior year				
8th prior year				
9th prior year				
10th prior year				
11th prior year				
12th prior year				
13th prior year				
14th prior year				
15th prior year				
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal		Québec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year			P				
Deduct: Additional deduction for gifts of medicine expired after five tax years	639						
Additional deduction for gifts of medicine at the beginning of the tax year	640		Q				
Add:							
Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year **610** ______

Québec

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year ______

Alberta

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year ______

where:

a is the **lesser** of line 2 and line 4

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

		Federal		Québec		Alberta
Subtotal (line 650 **plus** line 610)			R			
Subtotal (amount Q **plus** amount R)			S			
Deduct:						
Adjustment for an acquisition of control	655					
Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660					
Subtotal (line 655 **plus** line 660)			T			
Additional deduction for gifts of medicine closing balance (amount S **minus** amount T)	680					

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2012-12-31			
2nd prior year	2011-12-31			
3rd prior year	2010-12-31			
4th prior year	2009-12-31			
5th prior year	2009-10-08			
6th prior year*				
Total				

***** These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2012-12-31	
2nd prior year	2011-12-31	
3rd prior year	2010-12-31	
4th prior year	2009-12-31	
5th prior year	2009-10-08	
6th prior year*		
7th prior year		
8th prior year		
9th prior year		
10th prior year		
11th prior year		
12th prior year		
13th prior year		
14th prior year		
15th prior year		
16th prior year		
17th prior year		
18th prior year		
19th prior year		
20th prior year		
21st prior year*		
Total		

* These gifts expired in the current year.

T2 SCH 2 E (13) Canada

Canada Revenue Agency / Agence du revenu du Canada

Schedule 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*. This does not apply to tax years starting after March 20, 2013.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
755,089		755,089	86,835

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	86,835			
Deduct: Ontario small business deduction (from Schedule 500)	402				
Subtotal		86,835	►	86,835	A6
Add:					
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)				86,835	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Ontario tax credit for the purchase of vehicles that use natural gas as a fuel					
Subtotal			►		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				86,835	E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416		
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				86,835	F6
Deduct: Ontario corporate minimum tax credit (from Schedule 510)			418	1,732	
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				85,103	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal			►		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				85,103	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454	27,425			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal		27,425	►	27,425	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	57,678	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	57,678

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1	Pre Feb. 2005 Distribution Equip	28,621,021			0		28,621,021	4	0	0	1,144,841	27,476,180
2.	8	General Office/Stores Equipment	396,641	160,658		0	80,329	476,970	20	0	0	95,394	461,905
3.	10	Vehicles	1,243,800	533,990		0	266,995	1,510,795	30	0	0	453,239	1,324,551
4.	47	Distribution Equipment	48,284,054	4,460,879		22,638	2,219,121	50,503,174	8	0	0	4,040,254	48,682,041
5.	45	Computer Equipment	18,196			0		18,196	45	0	0	8,188	10,008
6.	13	Leasehold Improvements	28,945			0		28,945	NA	0	0	10,751	18,194
7.	12	Small tools	353,671	128,552		0	64,276	417,947	100	0	0	417,947	64,276
8.	46		96,926			0		96,926	30	0	0	29,078	67,848
9.	50	Computers	92,994	252,314		0	126,157	219,151	55	0	0	120,533	224,775
		Totals	79,136,248	5,536,393		22,638	2,756,878	81,893,125				6,320,225	78,329,778

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (11)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	1228158 Ontario Limited		88706 8690 RC0001	2	1	100.000			1
2.	16006059 Ontario Inc.		86184 9107 RC0001	3					
3.	52905 Newfoundland and Labrador		80392 9546 RC0001	3					
4.	630319 BC Ltd.		87011 0616 RC0001	3					
5.	BC Gas (Argentina) S.A.		NR	3					
6.	BC Gas (Malaysia) SDN. BHDS. A.		NR	3					
7.	BC Gas International (Middle East)		89059 8022 RC0001	3					
8.	BC Gas International Projects Ltd.		86892 1644 RC0001	3					
9.	Belize Electrical Company Limited	BZ	NR	3					
10.	Canadian Niagara Power Inc.		87249 8225 RC0002	3					
11.	Caribbean Utilities Company, Ltd.	KY	NR	3					
12.	Central Hudson Enterprise Corp.	US	NR	3					
13.	Central Hudson Gas & Electric Corp.	US	NR	3					
14.	CH Energy Group Inc.	US	NR	3					
15.	Color Acquisition Sub Inc.	US	NR	3					
16.	Cornwall Street Railway Light and P		12090 6839 RC0001	3					
17.	ESI Power-Walden Corporation		12628 4249 RC0001	3					
18.	Fortis Alberta Holdings Inc.		86921 0203 RC0001	3					
19.	Fortis Belize Limited	BZ	NR	3					
20.	Fortis Cayman Inc.	KY	NR	3					
21.	Fortis Energy (Bermuda) Ltd.	BM	NR	3					
22.	Fortis Energy (International) Belize	BZ	NR	3					
23.	Fortis Energy Cayman inc.	KY	NR	3					
24.	Fortis Energy Corporation		10386 4443 RC0001	3					
25.	Fortis Generation East GP Inc		83966 8308 RC0001	3					
26.	Fortis Generation Inc.		83967 1096 RC0001	3					
27.	Fortis Generation Similkameen GP I		83496 7838 RC0001	3					
28.	Fortis Hydro Corporation		NR	3					
29.	Fortis Inc.		10185 2416 RC0001	3					
30.	Fortis Properties Corporation		89693 2449 RC0001	3					
31.	Fortis TCI Limited	TC	NR	3					
32.	Fortis US Energy Corporation	US	NR	3					
33.	Fortis US Holdings Nova Scotia Limi		82872 6091 RC0001	3					
34.	Fortis West Inc.		87470 8209 RC0001	3					
35.	FortisAlberta Inc.		86929 4520 RC0001	3					
36.	FortisBC Alternative Energy Services		81144 5873 RC0001	3					
37.	FortisBC Energy (Vancouver Island)		12174 3074 RC0001	3					
38.	FortisBC Energy (Whistler) Inc.		89138 9652 RC0001	3					
39.	FortisBC Energy Inc.		10043 1592 RC0002	3					
40.	FortisBC Holdings Inc.		10534 9740 RC0004	3					
41.	FortisBC Huntington Inc.		12974 2870 RC0001	3					
42.	FortisBC Inc.		10564 5642 RC0001	3					
43.	FortisBC Pacific Holdings Inc.		87170 9101 RC0001	3					

	Name	Country of residence (other than Canada)	Business number (see note 1)	Relationship code (see note 2)	Number of common shares you own	% of common shares you own	Number of preferred shares you own	% of preferred shares you own	Book value of capital stock
	100	200	300	400	500	550	600	650	700
44.	FortisBC Storage Inc.		86014 6588 RC0001	3					
45.	FortisOntario District Heating Inc.		89329 1740 RC0001	3					
46.	FortisOntario Inc.		10076 8985 RC0003	1					
47.	FortisUS Inc.	US	NR	3					
48.	Griffith Energy Services Inc.	US	NR	3					
49.	Inland Energy Corp.		11960 8529 RC0001	3					
50.	Inland Pacific Energy Services		10249 0554 RC0001	3					
51.	Maritime Belize Limited	BZ	NR	3					
52.	Maritime Electric Cayman Inc.	KY	NR	3					
53.	Maritime Electric Company, Limited		12111 9879 RC0001	3					
54.	Mt. Hayes (GP) Ltd.		84888 3914 RC0001	3					
55.	Newfoundland Electric Company Lin		12748 1059 RC0001	3					
56.	Newfoundland Energy Cayman Inc.	KY	NR	3					
57.	Newfoundland Energy Holdings Inc.		82293 1242 RC0001	3					
58.	Newfoundland Energy Luxembourg	LU	NR	3					
59.	Newfoundland Industries Limited		87536 2774 RC0001	3					
60.	Newfoundland Power Inc.		10386 4831 RC0001	3					
61.	Terasen Gas Holdings Inc.		86602 7832 RC0001	3					
62.	Terasen International Inc.		13237 5346 RC0001	3					
63.	The Gananoque Water Power Comp		10521 4068 RC0001	3					
64.	Turks and Caicos Utilities Limited	TC	NR	3					
65.	Waneta Expansion General Partner		84815 4001 RC0001	3					
66.	West Kootenay Power Ltd.		89427 8670 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")				200	8,668,639	A
Add: Cost of eligible capital property acquired during the taxation year	222					
Other adjustments	226					
Subtotal (line 222 plus line 226)			x 3 / 4 =			B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228		x 1 / 2 =			C
amount B minus amount C (if negative, enter "0")				▶		D
Amount transferred on amalgamation or wind-up of subsidiary				224		E
Subtotal (add amounts A, D, and E)				230	8,668,639	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H			
Other adjustments	246		I			
(add amounts G,H, and I)			x 3 / 4 =	248		J
Cumulative eligible capital balance (amount F minus amount J)					8,668,639	K
(if amount K is negative, enter "0" at line M and proceed to Part 2)						
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business	249					
amount K	8,668,639					
less amount from line 249						
Current year deduction	8,668,639	x 7.00 % =	250	606,805 *		
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)				606,805 ▶	606,805	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")				300	8,061,834	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4			
Line 3 minus line 4 (if negative, enter "0")		▶		5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	409	▶		9	
Line 6 minus line 9 (if negative, enter "0")				▶	O
Line N minus line O (if negative, enter "0")					P
		Line 5	x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")					R
		Amount R	x 2 / 3 =		S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410	

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Accrued Pension Benefit Asset	-2,142,948		-334,848	-197,414	-2,280,382
2	Accrued Post Retirement Benef	4,616,987		851,100	123,610	5,344,477
3						
	Reserves from Part 2 of Schedule 13					
	Totals	2,474,039		516,252	-73,804	3,064,095

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*;
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- Investments or expenditures, described in subsection 127(9) of the Act and Part XLVI of the Regulations, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim;*
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release*.*
- For more information on SR&ED, see Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada*, and T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*. Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **www.cra.gc.ca/txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21 of the Act), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) of the Act for more information.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) of the Act for more information.

Detailed information (continued)

- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures***:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013***	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures****:	
– after March 28, 2012, and before 2014****	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015****	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** Pre-production mining exploration expenditures are described in subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9).

**** A transitional relief rate of 10% may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraph (k)(ii) of the definition of **specified percentage** in subsection 127(9) for more information. Pre-production mining development expenditures are described in subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9).

Corporation's name	Business number	Tax year-end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . **102** 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED* . . . . **103** ________

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see Guide RC4088, *General Index of Financial Information (GIFI)*. Enter contributions on line 350 of Part 8.

* Enter only contributions not already included on Form T661. Include all of the contributions made before 2013 and 80% of the contributions made after 2012.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

CCA* class number **105**	Description of investment **110**	Date available for use **115**	Location used (province or territory) **120**	Amount of investment **125**
			Total of investments for qualified property and qualified resource property	A

* CCA: capital cost allowance

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year . . . . B

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal (line 210 **plus** line 215) ▶ C

ITC at the beginning of the tax year (amount B **minus** amount C) 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part of amount A from Part 4) . . . . . . x 10 % = 240

Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part of amount A from Part 4) . . . . . . x 5 % = 242

Credit allocated from a partnership 250

Subtotal (total of lines 230 to 250) ▶ D

Total credit available (line 220 **plus** amount D) . . . . E

Deduct:

Credit deducted from Part I tax (enter at amount D in Part 30) 260

Credit carried back to the previous year(s) (amount H from Part 6) . . . . . . a

Credit transferred to offset Part VII tax liability 280

Subtotal (total of line 260, amount a, and line 280) ▶ F

Credit balance before refund (amount E **minus** amount F) . . . . G

Deduct:

Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) 310

ITC closing balance of investments from qualified property and qualified resource property (amount G **minus** line 310) 320

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day			
1st previous tax year				. . . . . . Credit to be applied	901	
2nd previous tax year				. . . . . . Credit to be applied	902	
3rd previous tax year				. . . . . . Credit to be applied	903	

Total (enter at amount a in Part 5) H

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 from Part 5) I

Credit balance before refund (amount G from Part 5) . . . . J

Refund (40 % of amount I or J, whichever is less) . . . . K

Enter amount K or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661) . . . .

Add:

Contributions to agricultural organizations for SR&ED* . . . .

Current expenditures (line 557 on Form T661 **plus** line 103 from Part 3)* . . . . ▶ **350**

Capital expenditures incurred **before** 2014 (from line 558 on Form T661)** **360**

Repayments made in the year (from line 560 on Form T661) **370**

Qualified SR&ED expenditures (total of lines 350 to 370) **380**

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates an SR&ED expenditure limit is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . **385** 1 Yes [ ] 2 No [X]

Complete lines 390 and 398 if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied) **390**

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million **398**

* If either of the tax years referred to at line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in these tax years.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone corporation: $ 8,000,000

Deduct:

Taxable income for the previous tax year (line 390 from Part 9) or $500,000, whichever is more ______ x 10 = ______ A

Excess ($8,000,000 **minus** amount A; if negative, enter "0") . . . . B

$ 40,000,000 **minus** line 398 from Part 9 . . . . ______ a

Amount a **divided** by $ 40,000,000 C

Expenditure limit for the stand-alone corporation (amount B **multiplied** by amount C) . . . . D*

For an associated corporation:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** E*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount D or E ______ x $\frac{\text{Number of days in the tax year}}{365}$ 365 = ... F

Your SR&ED expenditure limit for the year (enter the amount from line D, E, or F, whichever applies) **410**

* Amount D or E cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10), whichever is less*	420		x 35 % =		G
Line 350 **minus** line 410 (if negative, enter "0")**	430		x 20 % =		H
Line 410 **minus** line 350 (if negative, enter "0")			b		
Capital expenditures (line 360 from Part 8) or amount b above, whichever is less*	440		x 35 % =		I
Line 360 **minus** amount b above (if negative, enter "0")**	450		x 20 % =		J
Repayments (amount from line 370 in Part 8)					

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.**

460		x 35 % =		c
480		x 20 % =		d

Subtotal (amount c **plus** amount d) ▶ K

Current-year SR&ED ITC (total of amounts G to K; enter on line 540 in Part 12) L

* For corporations that are not CCPCs, enter "0" for amounts G and I.

** For tax years that end after 2013, the general SR&ED rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year M

Deduct:

Credit deemed as a remittance of co-op corporations 510

Credit expired 515

Subtotal (line 510 **plus** line 515) ▶ N

ITC at the beginning of the tax year (amount M **minus** amount N) 520

Add:

Credit transferred on amalgamation or wind-up of subsidiary 530

Total current-year credit (from amount L in Part 11) 540

Credit allocated from a partnership 550

Subtotal (total of lines 530 to 550) ▶ O

Total credit available (line 520 **plus** amount O) P

Deduct:

Credit deducted from Part I tax (enter at amount E in Part 30) 560

Credit carried back to the previous year(s) (amount S from Part 13) e

Credit transferred to offset Part VII tax liability 580

Subtotal (total of line 560, amount e, and line 580) ▶ Q

Credit balance before refund (amount P **minus** amount Q) R

Deduct:

Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies) 610

ITC closing balance on SR&ED (amount R **minus** line 610) 620

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter at amount e in Part 12)		S

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . 650 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 from Part 12 **minus** amount K from Part 11) . . . ______ f

Refundable credits (amount f above or amount R from Part 12, whichever is less)* . . . ______ T

Deduct:

Amount T or amount G from Part 11, whichever is less . . . ______ U

Net amount (amount T **minus** amount U; if negative, enter "0") . . . ______ V

Amount V **multiplied** by 40 % . . . ______ W

Add:

Amount U . . . ______ X

Refund of ITC (amount W **plus** amount X – enter this, or a lesser amount, on line 610 in Part 12) . . . ______ Y

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined at line 101 in Part 2.

Credit balance before refund (amount R from Part 12) . . . ______ Z

Deduct:

Amount Z or amount G from Part 11, whichever is less . . . ______ AA

Net amount (amount Z **minus** amount AA; if negative, enter "0") . . . ______ BB

Amount BB or amount I from Part 11, whichever is less . . . ______ CC

Amount CC **multiplied** by 40 % . . . ______ DD

Add :

Amount AA . . . ______ EE

Refund of ITC (amount DD **plus** amount EE) . . . ______ FF

Enter FF, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less

Subtotal (enter this amount at amount C in Part 17) ______ A

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B in Part 16 on page 9.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B below.

D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less

Subtotal (enter this amount at amount D in Part 17) ______ B

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760 below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported at amount E in Part 17) **760** ____________

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from amount A in Part 16		C
Recaptured ITC for calculation 2 from amount B in Part 16		D
Recaptured ITC for calculation 3 from line 760 in Part 16		E
Total recapture of SR&ED investment tax credit – total of amounts C to E		F

Enter amount F at amount A in Part 29.

Pre-Production Mining

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810	
Geological, geophysical, or geochemical surveys	811	
Drilling by rotary, diamond, percussion, or other methods	812	
Trenching, digging test pits, and preliminary sampling	813	

Development:

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820	
Sinking a mine shaft, constructing an adit, or other underground entry	821	

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts in column 826 ▶		A
Total pre-production mining expenditures (total of lines 810 to 821 and amount A)	830	

Deduct:

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832	
Excess (line 830 **minus** line 832) (if negative, enter "0")		B

Add:

Repayments of government and non-government assistance	835	
Pre-production mining expenditures (amount B **plus** line 835)		C

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year .... D

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired 845

Subtotal (line 841 **plus** line 845) ▶ E

ITC at the beginning of the tax year (amount D **minus** amount E) 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Pre-production mining expenditures* incurred before January 1, 2013 (applicable part of amount C from Part 18) .. 870 x 10 % = a

Pre-production mining exploration expenditures incurred in 2013 (applicable part of amount C from Part 18) .. 872 x 5 % = b

Pre-production mining development expenditures incurred in 2014 (applicable part of amount C from Part 18) .. 874 x 7 % = c

Pre-production mining development expenditures incurred in 2015 (applicable part of amount C from Part 18) .. 876 x 4 % = d

Current year credit (total of amounts a to d) 880 ▶ F

Total credit available (total of lines 850, 860, and amount F) .... G

Deduct:

Credit deducted from Part I tax (enter at amount F in Part 30) 885

Credit carried back to the previous year(s) (amount I from Part 20) .... e

Subtotal (line 885 **plus** amount e) ▶ H

ITC closing balance from pre-production mining expenditures (amount G **minus** amount H) 890

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	921
2nd previous tax year				Credit to be applied	922
3rd previous tax year				Credit to be applied	923

Total (enter at amount e in Part 19) I

Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) .... 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	2356	Agricultural Equipment Technician	49,203	4,920	2,000
2.	PC7032	Powerline Tehcnician	50,069	5,007	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
3.	BA5839	Agricultural Equipment Technician	39,040	3,904	2,000

Total current-year credit (enter at line 640 in Part 22) 6,000 A

* Net of any other government or non-government assistance received or to be received.

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year . . . . . B

Deduct:

Credit deemed as a remittance of co-op corporations 612

Credit expired after 20 tax years 615

Subtotal (line 612 **plus** line 615) ▶ C

ITC at the beginning of the tax year (amount B **minus** amount C) 625

Add:

Credit transferred on amalgamation or wind-up of subsidiary 630

ITC from repayment of assistance 635

Total current-year credit (amount A from Part 21) 640 6,000

Credit allocated from a partnership 655

Subtotal (total of lines 630 to 655) 6,000 ▶ 6,000 D

Total credit available (line 625 **plus** amount D) . . . . . 6,000 E

Deduct:

Credit deducted from Part I tax (enter at amount G in Part 30) 660 6,000

Credit carried back to the previous year(s) (amount G from Part 23) . . . . . a

Subtotal (line 660 **plus** amount a) 6,000 ▶ 6,000 F

ITC closing balance from apprenticeship job creation expenditures (amount E **minus** amount F) 690

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	

Total (enter at amount a in Part 22) G

Child Care Spaces

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year **715** ______

Add:

Specified child care start-up expenditures from the current tax year . . . . **705** ______

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . ______ A

Deduct:

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line A . . . . **725** ______

Excess (amount A **minus** line 725) (if negative, enter "0") . . . . ______ B

Add:

Repayments by the corporation of government and non-government assistance . . . . **735** ______

Total eligible expenditures for child care spaces (amount B **plus** line 735) . . . . **745** ______

* CCA: capital cost allowance

Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745) . . . . ______ x 25 % = ______ C

Number of child care spaces . . . . **755** ______ x $ 10,000 = ______ D

ITC from child care spaces expenditures (amount C or D, whichever is less) . . . . ______ E

Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				F
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)			▶	G
ITC at the beginning of the tax year (amount F **minus** amount G)			775	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (amount E from Part 25)	780			
Credit allocated from a partnership	782			
Subtotal (total of lines 777 to 782)			▶	H
Total credit available (line 775 **plus** amount H)				I
Deduct:				
Credit deducted from Part I tax (enter at amount H in Part 30)	785			
Credit carried back to the previous year(s) (amount K from Part 27)			a	
Subtotal (line 785 **plus** amount a)			▶	J
ITC closing balance from child care spaces expenditures (amount I **minus** amount J)			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year / Month / Day			
1st previous tax year	2012-12-31	Credit to be applied	941	
2nd previous tax year	2011-12-31	Credit to be applied	942	
3rd previous tax year	2010-12-31	Credit to be applied	943	
		Total (enter at amount a in Part 26)		K

Recapture – Child Care Spaces

Part 28 – Recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . **792** ____________

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ____________

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . **797** ____________

Amount from line 795 or line 797, whichever is less . . . . ____________ A

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799** ____________

Total recapture of child care spaces investment tax credit (total of line 792, amount A, and line 799) . . . . ____________ B

Enter amount B at amount B in Part 29.

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (from amount F in Part 17)		A
Recaptured child care spaces ITC (from amount B in Part 28)		B
Total recapture of investment tax credit (amount A **plus** amount B)		C

Enter amount C on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		D
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)		E
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		F
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	6,000	G
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		H
Total ITC deducted from Part I tax (total of amounts D to H)	6,000	I

Enter amount I at line 652 of the T2 return.

Privacy Act, Personal Information Bank number CRA PPU 047

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
6,000	6,000			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2009-10-08				
Total				

B+C+D+G	**Total ITC utilized**	6,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2011 / Number of days in the tax year	/ 365	x	12.00 %	=	%	A1
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	365 / 365	x	11.50 %	=	11.50000 %	A2

Ontario basic rate of tax for the year (rate A1 **plus** A2) 11.50000 ► 11.50000 % A3

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 755,089 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A3 from Part 1) . . . . . . 86,835 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)		1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)		2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)		3
Enter the least of amounts 1, 2, and 3		D

Ontario domestic factor: Ontario taxable income * / Taxable income earned in all provinces and territories ** = 755,089.00 / 755,089 = 1.00000 E

Amount D x factor E		a
Ontario taxable income (amount B from Part 2)	755,089	b

Ontario small business income (lesser of amount a and amount b) ______ F

Number of days in the tax year before July 1, 2011 / Number of days in the tax year = ____ / 365 x 7.50 % = ____ % G1

Number of days in the tax year after June 30, 2011 / Number of days in the tax year = 365 / 365 x 7.00 % = 7.00000 % G2

OSBD rate for the year (rate G1 **plus** G2) 7.00000 % G3

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G3) ______ H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount b from Part 3) ______ I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17			J
Deduct:			
Ontario adjusted small business income (amount I from Part 4)			K
Subtotal (amount J **minus** amount K) (if negative, enter "0")			L
OSBD rate for the year (rate G3 from Part 3)	7.00000 %		
Amount L **multiplied** by the OSBD rate for the year			M
Ontario domestic factor (factor E from Part 3)		1.00000	N
Ontario credit union tax reduction (amount M **multiplied** by factor N)			O

Enter amount O on line 410 of Schedule 5.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	104,415,932
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	267,786,319
Total assets (total of lines 112 to 116)		372,202,251
Total revenue of the corporation for the tax year **	142	39,772,456
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	152,979,544
Total revenue (total of lines 142 to 146)		192,752,000

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	2,456,941
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	268,116		
Provision for deferred income taxes (debits)/cost of future income taxes	222	160,803		
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		428,919		428,919 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal				B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	2,885,860

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515	2,885,860	
Deduct:				
CMT loss available (amount R from Part 7)	5,446,430			
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available	5,446,430 ▶		5,446,430	C
Net income subject to CMT calculation (if negative, enter "0")		520		

Amount from line 520 ______ x (Number of days in the tax year before July 1, 2010 ______ / Number of days in the tax year 365) x 4 % = ______ 1

Amount from line 520 ______ x (Number of days in the tax year after June 30, 2010 365 / Number of days in the tax year 365) x 2.7 % = ______ 2

Subtotal (amount 1 **plus** amount 2) ______ 3

Gross CMT: amount on line 3 above x OAF **	540		
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")			D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		86,835	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		1,732	G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)		1,732	▶ 620	1,732	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)			650		
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				1,732	H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)				1,732	I
Subtotal (amount H **minus** amount I)					J
Add:					
Net CMT payable (amount E from Part 3)					
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal			▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670		L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				1,732	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		86,835	1		
For a corporation that is not a life insurance corporation:					
CMT after foreign tax credit deduction (amount D from Part 3)		2			
For a life insurance corporation:					
Gross CMT (line 540 from Part 3)		3			
Gross SAT (line 460 from Part 6 of Schedule 512)		4			
The **greater** of amounts 3 and 4		5			
Deduct: line 2 or line 5, whichever applies:			6		
Subtotal (if negative, enter "0")		86,835	▶	86,835	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		86,835			
Deduct:					
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		27,425			
Subtotal (if negative, enter "0")		59,410	▶	59,410	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)				1,732	P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – CMT loss carryforward

CMT loss carryforward at the end of the previous tax year *		5,446,430 Q		
Deduct:				
CMT loss expired *	700			
CMT loss carryforward at the beginning of the tax year * (see note below)		5,446,430 ►	720	5,446,430
Add:				
CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below)			750	
CMT loss available (line 720 **plus** line 750)				5,446,430 R
Deduct:				
CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3)				2,885,860
Subtotal (if negative, enter "0")				2,560,570 S
Add:				
Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount)			760	
CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760)			770	2,560,570 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency   Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	1228158 Ontario Limited	88706 8690 RC0001	1	0
2	16006059 Ontario Inc.	86184 9107 RC0001	0	0
3	52905 Newfoundland and Labrador	80392 9546 RC0001	0	0
4	630319 BC Ltd.	87011 0616 RC0001	0	0
5	BC Gas (Argentina) S.A.	NR	0	0
6	BC Gas (Malaysia) SDN. BHDS. A.	NR	0	0
7	BC Gas International (Middle East)	89059 8022 RC0001	0	0
8	BC Gas International Projects Ltd.	86892 1644 RC0001	0	0
9	Belize Electrical Company Limited	NR	0	0
10	Canadian Niagara Power Inc.	87249 8225 RC0002	131,198,300	78,609,974
11	Caribbean Utilities Company, Ltd.	NR	0	0
12	Central Hudson Enterprise Corp.	NR	0	0
13	Central Hudson Gas & Electric Corp.	NR	0	0
14	CH Energy Group Inc.	NR	0	0
15	Color Acquisition Sub Inc.	NR	0	0
16	Cornwall Street Railway Light and Power Company Li	12090 6839 RC0001	63,467,178	70,223,855
17	ESI Power-Walden Corporation	12628 4249 RC0001	0	0
18	Fortis Alberta Holdings Inc.	86921 0203 RC0001	0	0
19	Fortis Belize Limited	NR	0	0
20	Fortis Cayman Inc.	NR	0	0
21	Fortis Energy (Bermuda) Ltd.	NR	0	0
22	Fortis Energy (International) Belize	NR	0	0
23	Fortis Energy Cayman inc.	NR	0	0
24	Fortis Energy Corporation	10386 4443 RC0001	0	0
25	Fortis Generation East GP Inc	83966 8308 RC0001	0	0
26	Fortis Generation Inc.	83967 1096 RC0001	0	0
27	Fortis Generation Similkameen GP I	83496 7838 RC0001	0	0
28	Fortis Hydro Corporation	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
29	Fortis Inc.	10185 2416 RC0001	0	0
30	Fortis Properties Corporation	89693 2449 RC0001	0	0
31	Fortis TCI Limited	NR	0	0
32	Fortis US Energy Corporation	NR	0	0
33	Fortis US Holdings Nova Scotia Limited	82872 6091 RC0001	0	0
34	Fortis West Inc.	87470 8209 RC0001	0	0
35	FortisAlberta Inc.	86929 4520 RC0001	0	0
36	FortisBC Alternative Energy Services Inc.	81144 5873 RC0001	0	0
37	FortisBC Energy (Vancouver Island) Inc.	12174 3074 RC0001	0	0
38	FortisBC Energy (Whistler) Inc.	89138 9652 RC0001	0	0
39	FortisBC Energy Inc.	10043 1592 RC0002	0	0
40	FortisBC Holdings Inc.	10534 9740 RC0004	0	0
41	FortisBC Huntington Inc.	12974 2870 RC0001	0	0
42	FortisBC Inc.	10564 5642 RC0001	0	0
43	FortisBC Pacific Holdings Inc.	87170 9101 RC0001	0	0
44	FortisBC Storage Inc.	86014 6588 RC0001	0	0
45	FortisOntario District Heating Inc.	89329 1740 RC0001	21,558	0
46	FortisOntario Inc.	10076 8985 RC0003	73,044,393	4,145,715
47	FortisUS Inc.	NR	0	0
48	Griffith Energy Services Inc.	NR	0	0
49	Inland Energy Corp.	11960 8529 RC0001	0	0
50	Inland Pacific Energy Services	10249 0554 RC0001	0	0
51	Maritime Belize Limited	NR	0	0
52	Maritime Electric Cayman Inc.	NR	0	0
53	Maritime Electric Company, Limited	12111 9879 RC0001	0	0
54	Mt. Hayes (GP) Ltd.	84888 3914 RC0001	0	0
55	Newfoundland Electric Company Limited	12748 1059 RC0001	0	0
56	Newfoundland Energy Cayman Inc.	NR	0	0
57	Newfoundland Energy Holdings Inc.	82293 1242 RC0001	0	0
58	Newfoundland Energy Luxembourg	NR	0	0
59	Newfoundland Industries Limited	87536 2774 RC0001	0	0
60	Newfoundland Power Inc.	10386 4831 RC0001	0	0
61	Terasen Gas Holdings Inc.	86602 7832 RC0001	0	0
62	Terasen International Inc.	13237 5346 RC0001	0	0
63	The Gananoque Water Power Company	10521 4068 RC0001	54,889	0
64	Turks and Caicos Utilities Limited	NR	0	0
65	Waneta Expansion General Partner	84815 4001 RC0001	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
66	West Kootenay Power Ltd.	89427 8670 RC0001	0	0
		Total	450 267,786,319	550 152,979,544

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

T2 SCH 511 Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Algoma Power Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2009-01-26	2196355

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
2	Sackville	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Sault Ste Marie	ON	CA	P6B 6J6

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 King (Last name) **451** Glen (First name)

454 ______________________, (Middle name(s))

460 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number	**530** Street name/Rural route/Lot and Concession number	**540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Algoma Power Inc.	82249 4290 RC0001	2013-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	120 Telephone number including area code
Harry Clutterbuck	(905) 871-0330

Is the claim filed for an ATTC earned through a partnership? * . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . **160** ____________

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * 300 6,719,563

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . 310 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . 312 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
1.	425a	Agricultural Equipment Technician	Troy Senecal
2.	434a	Powerline Technician	Jason Bird
3.	425a	Agricultural Equipment Technician	Matt Lacroix
4.			

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
1.	2356	2011-09-27	2013-01-01	2013-12-31
2.	PC7032	2011-08-10	2013-01-01	2013-12-31
3.	BA5839	2012-06-25	2013-01-01	2013-12-31
4.				

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		365	365	10,000
2.		365	365	10,000
3.		271	271	7,425
4.				

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		64,765	64,765	22,668
2.		84,558	84,558	29,595
3.		39,040	39,040	13,664
4.				

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	10,000		10,000
2.	10,000		10,000
3.	7,425		7,425
4.			

Ontario apprenticeship training tax credit (total of amounts in column N) 500 27,425 **O**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ______ x percentage on line 170 in Part 1 ______ % = ... ______ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . Algoma Power Inc.

Taxation Year . . . . 2013-01-01 to 2013-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . Y

Corporation is related . . . . Y

Number of associated corporations . . . 66

Type of corporation . . . . Corporation Controlled by a Public Corporation

Total amount due (refund) federal and provincial* . . . . -185,059

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income	791,458
Taxable income	755,089
Donations	19,543
Calculation of income from an active business carried on in Canada	791,458
Dividends paid	
Dividends paid – Regular	
Dividends paid – Eligible	
Balance of the low rate income pool at the end of the previous year	
Balance of the low rate income pool at the end of the year	
Balance of the general rate income pool at the end of the previous year	
Balance of the general rate income pool at the end of the year	
Part I tax (base amount)	286,934

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	107,263	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	350,000
Investment tax credits	6,000	Other*		Surtax credit	
Abatement/Other*	173,671	Provincial or territorial tax	57,678	Other*	

Balance due/refund (–) -185,059

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Cumulative eligible capital	8,061,834
Financial statement reserve	3,064,095

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	791,458		
Taxable income	755,089		
% Allocation	100.00		
Attributed taxable income	755,089		
Tax payable before deduction*	86,835		
Deductions and credits	1,732		
Net tax payable	85,103		
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***	85,103		
Instalments and refundable credits	27,425		
Balance due/Refund (-)	57,678		
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax loss that can be carried forward over 20 years – Schedule 510 . . . 2,560,570

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Algoma Power Inc.			41,683,727	41,683,727
1228158 Ontario Limited	1		1	1
16006059 Ontario Inc.				
52905 Newfoundland and Labrador				
630319 BC Ltd.				
BC Gas (Argentina) S.A.				
BC Gas (Malaysia) SDN. BHDS. A.				
BC Gas International (Middle East)				
BC Gas International Projects Ltd.				
Belize Electrical Company Limited				
Canadian Niagara Power Inc.	41,314,962		45,374,983	45,374,983
Caribbean Utilities Company, Ltd.				
Central Hudson Enterprise Corp.				
Central Hudson Gas & Electric Corp.				
CH Energy Group Inc.				
Color Acquisition Sub Inc.				
Cornwall Street Railway Light and Power Company Limited	20,709,025		22,072,035	22,072,035
ESI Power-Walden Corporation				
Fortis Alberta Holdings Inc.				
Fortis Belize Limited				

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Fortis Cayman Inc.				
Fortis Energy (Bermuda) Ltd.				
Fortis Energy (International) Belize				
Fortis Energy Cayman inc.				
Fortis Energy Corporation				
Fortis Generation East GP Inc				
Fortis Generation Inc.				
Fortis Generation Similkameen GP I				
Fortis Hydro Corporation				
Fortis Inc.				
Fortis Properties Corporation				
Fortis TCI Limited				
Fortis US Energy Corporation				
Fortis US Holdings Nova Scotia Limited				
Fortis West Inc.				
FortisAlberta Inc.				
FortisBC Alternative Energy Services Inc.				
FortisBC Energy (Vancouver Island) Inc.				
FortisBC Energy (Whistler) Inc.				
FortisBC Energy Inc.				
FortisBC Holdings Inc.				
FortisBC Huntington Inc.				
FortisBC Inc.				
FortisBC Pacific Holdings Inc.				
FortisBC Storage Inc.				
FortisOntario District Heating Inc.	2,871		2,871	2,871
FortisOntario Inc.	173,870,846		179,251,714	179,251,714
FortisUS Inc.				
Griffith Energy Services Inc.				
Inland Energy Corp.				
Inland Pacific Energy Services				
Maritime Belize Limited				
Maritime Electric Cayman Inc.				
Maritime Electric Company, Limited				
Mt. Hayes (GP) Ltd.				
Newfoundland Electric Company Limited				
Newfoundland Energy Cayman Inc.				
Newfoundland Energy Holdings Inc.				
Newfoundland Energy Luxembourg				
Newfoundland Industries Limited				
Newfoundland Power Inc.				
Terasen Gas Holdings Inc.				
Terasen International Inc.				
The Gananoque Water Power Company	54,889		54,889	54,889
Turks and Caicos Utilities Limited				
Waneta Expansion General Partner				
West Kootenay Power Ltd.				
Total	235,952,594		288,440,220	288,440,220

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total			

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)	Taxable capital used to calculate the Nova Scotia capital deduction on large corporations (Schedule 343)
Total		

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	2013-12-31	2012-12-31	2011-12-31	2010-12-31	2009-12-31
Net income	791,458	-399,357	394,390	719,644	212,861
Taxable income	755,089		376,398	707,972	211,706
Active business income	791,458		394,390	719,644	212,861
Dividends paid					
Dividends paid – Regular					
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year					
GRIP – end of the year					
Donations	19,543	16,826	17,992	11,672	1,155
Balance due/refund (-)	-185,059	-150,000	-224,054	-38,703	-4,007
Loss carrybacks requested in prior years					
Taxable income before loss carrybacks	N/A	N/A	376,398	707,972	211,706
Non-capital losses	N/A	N/A		228,800	170,557
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A		228,800	170,557
Adjusted taxable income after loss carrybacks	N/A	N/A	376,398	479,172	41,149
Losses in the current year carried back to previous years (according to Schedule 4)					
Adjusted taxable income before current year loss carrybacks*	N/A		376,398	479,172	N/A
Non-capital losses	N/A				N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted taxable income after loss carrybacks	N/A		376,398	479,172	N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

Federal taxes

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Part I before surtax	107,263		62,105	127,435	40,223
Surtax					
Part IV					
Part I & Surtax	107,263		62,105	127,435	40,223
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Small business deduction					
M&P deduction					
Foreign tax credit					
Political contribution					
Investment tax credit	6,000				
Abatement/other*	173,671		80,926	141,594	40,225

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

ITC refund					
Dividend refund					
Instalments	350,000	150,000	330,378	318,019	110,000
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2013-12-31	2012-12-31	2011-12-31	2010-12-31	2009-12-31
Net income	791,458	-399,357	394,390	719,644	212,861
Taxable income	755,089		376,398	707,972	211,706
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income	755,089		376,398	707,972	211,706
Surtax					
Income tax payable before deduction	86,835		44,219	91,978	29,639
Income tax deductions /credits	1,732				1,503
Net income tax payable	85,103		44,219	91,978	28,136
Taxable capital				82,936,699	74,979,654
Capital tax payable				59,903	37,634
Total tax payable*	85,103		44,219	151,881	65,770
Instalments and refundable credits	27,425				
Balance due/refund**	57,678		44,219	151,881	65,770

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

<u>4-Energy Probe-29</u>

Ref: Exhibit 4, Tab 12, Schedule 4

a) **Has API had any tax credits (Ontario apprenticeship training, Ontario co-operative education, federal job creation, etc.) in 2011 through 2013? If yes please identify the number of positions and the credits claimed.**

b) **Does API have any positions in 2014 and/or 2015 that would qualify for any of the tax credits noted in part (a)? If yes, please indicate how many and what the associated tax credit is.**

RESPONSE:

a) Yes, tax credits were claimed over the past three years as follows:

- 2011 and 2012 – No tax credits claimed for the Ontario apprenticeship training, Ontario cooperative education, and Federal job creation tax credits
- 2013 – Ontario apprenticeship training tax credit – 3 claims, – $27,425 total claim
- 2013 – Ontario cooperative education tax credit – no tax credit claimed
- 2013 – Federal job creation tax credit – 3 claims, – $6,000 total claim

b) Yes, API currently does have positions that will qualify to be claimed in the future as follows:

- Ontario apprenticeship training tax credit – 3 positions for 2014, tax credit estimation = $22,247, 1 position for 2015, tax credit estimation =$7,425*
- Ontario cooperative education tax credit – no positions for 2014 & 2015
- Federal job creation tax credit – 1 position for 2014, tax credit estimation = $2,000, no claim for 2015*

*It is not possible to accurately quantify future tax credits until the end of the applicable year when each claimant's total wages and benefits as well as total days employed can be determined. The above amounts are estimates based on 2013 salary data and tax law effective as at December 31, 2013.

4-Energy Probe-30

Ref: Exhibit 4, Tab 12, Schedule 5

Please explain the significant increase in property taxes forecast for 2015 relative to 2014 and 2013.

RESPONSE:

API purchased a newer facility to replace the Wawa Service Centre including adequate storage for inventory. The existing service center will be demolished and the property will be dedicated to the substation (Wawa #2 Sub) currently occupying the footprint.

(page left blank intentionally)

4.0 -VECC - 18

Reference: E4/T2/S1/pg.1 Appendix 2-JA / 4/T3/S1/pg.2/Table 4.3.1.1

Preamble: The OEB requires distributors adopting IFRS to present one year of comparative information in its first IFRS financial statements for financial reporting purposes. The equivalent change for API is the adoption of ASPE in 2011, changes to deprecation and capitalization policies as of January 1, 2013, and the adoption of ASPE 3462 as of January 1, 2014. However API has not presented any comparative information with respect to OM&A for 2014.

a) Please provide an amended Appendix 2-JA which shows for 2014 separately the adjustments for the change in depreciation and capitalization policies.
b) Please provide the same for Table 4.3.1.1

RESPONSE:

a) The changes in depreciation and capitalization policies were effective January 1, 2013, therefore the requested schedules in Appendix 2-JA have been adjusted to show 2013 as well as 2014 as though the accounting policy changes had not been made.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals Without Changes to the Accounting Policies	2014 Bridge Year Without Changes to the Accounting Policies	2015 Test Year
Reporting Basis						
Operations	$ 1,801,754	$ 1,322,446	$ 1,685,078	$ 1,492,104	$ 1,907,277	$ 1,796,392
Maintenance	$ 4,258,631	$ 4,223,860	$ 4,062,359	$ 4,155,917	$ 3,859,594	$ 5,344,753
SubTotal	**$ 6,060,385**	**$ 5,546,305**	**$ 5,747,437**	**$ 5,648,020**	**$ 5,766,871**	**$ 7,141,145**
%Change (year over year)			3.6%	-1.7%	2.1%	23.8%
%Change (Test Year vs Last Rebasing Year - Actual)						28.8%
Billing and Collecting	$ 1,311,726	$ 1,658,252	$ 814,619	$ 928,588	$ 1,023,262	$ 1,090,941
Community Relations	$ 10,000	$ 372	$ 16,300	$ 19,759	$ 16,700	$ 26,352
Administrative and General	$ 2,208,096	$ 2,323,382	$ 2,955,553	$ 3,122,531	$ 3,269,819	$ 4,554,240
SubTotal	**$ 3,529,822**	**$ 3,982,006**	**$ 3,786,472**	**$ 4,070,877**	**$ 4,309,781**	**$ 5,671,534**
%Change (year over year)			-4.9%	7.5%	5.9%	31.6%
%Change (Test Year vs Last Rebasing Year - Actual)						42.4%
Total	**$ 9,590,207**	**$ 9,528,311**	**$ 9,533,910**	**$ 9,718,897**	**$ 10,076,652**	**$ 12,812,679**
%Change (year over year)			0.1%	1.9%	3.7%	27.2%

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals Without Changes to the Accounting Policies	2014 Bridge Year Without Changes to the Accounting Policies	2015 Test Year
Operations	$ 1,801,754	$ 1,322,446	$ 1,685,078	$ 1,492,104	$ 1,907,277	$ 1,796,392
Maintenance	$ 4,258,631	$ 4,223,860	$ 4,062,359	$ 4,155,917	$ 3,859,594	$ 5,344,753
Billing and Collecting	$ 1,311,726	$ 1,658,252	$ 814,619	$ 928,588	$ 1,023,262	$ 1,090,941
Community Relations	$ 10,000	$ 372	$ 16,300	$ 19,759	$ 16,700	$ 26,352
Administrative and General	$ 2,208,096	$ 2,323,382	$ 2,955,553	$ 3,122,531	$ 3,269,819	$ 4,554,240
Total	**$ 9,590,207**	**$ 9,528,311**	**$ 9,533,910**	**$ 9,718,897**	**$ 10,076,652**	**$ 12,812,679**
%Change (year over year)			0.1%	1.9%	3.7%	27.2%

b) The changes in depreciation and capitalization policies were effective January 1, 2013, therefore the requested schedules in Table 4.3.1.1 have been adjusted to show 2013 as well as 2014 as though the accounting policy changes had not been made.

Table 4.3.1.1

Programs	2011 Board Approved	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals Without Changes to the Accounting Policies	2014 Bridge Year Without Changes to the Accounting Policies	2015 Test Year
Operations and Maintenance Programs						
Engineering	332,358	336,159	397,374	321,352	429,365	404,403
SCADA and Dispatch	90,497	73,354	69,844	11,028	80,000	256,000
Lines	1,542,755	1,582,201	1,269,302	1,588,980	1,478,936	1,662,357
Distribution Stations	433,757	393,364	345,341	426,730	396,488	482,304
Vegetation Management	2,600,924	2,585,736	2,702,262	2,590,888	2,682,086	3,426,180
Metering	770,248	721,238	1,060,940	951,356	1,004,538	999,500
Customer Services	879,504	921,062	731,219	841,339	869,875	1,020,233
Materials Mgmt	180,068	240,289	198,864	245,670	272,293	260,622
Facilities	509,150	513,718	490,740	539,446	689,789	624,242
Non-attributable costs				(127,443)	(187,287)	
	7,339,261	7,367,122	7,265,885	7,389,346	7,716,084	9,135,840
Administration						
General Administration	3,125,275	3,248,306	3,402,536	3,305,937	3,358,907	3,505,698
GEC	(874,329)	(1,087,117)	(1,176,834)	(1,141,700)	(1,154,690)	-
	2,250,946	2,161,189	2,225,702	2,164,237	2,204,217	3,505,698
Miscellaneous other			42,322	165,314	156,352	171,140
Total	9,590,207	9,528,311	9,533,909	9,718,897	10,076,653	12,812,678

(page left blank intentionally)

4.0-VECC-19

Reference: E4/T1/S1/Appendix A

a) Please provide the cost-benefit analysis that was undertaken in support of the expanded vegetation program.
b) Please provide the estimated reduced outage cost savings for the program for the years 2015 through 2019.
c) Please explain the consequence of a 20% reduction in the 2015 vegetation management program. Please provide the evidentiary support or analysis for any purported degradation in service due to a reduction in vegetation management to traditional levels.

RESPONSE:

a) The "Performance Management Review and Quantification of Vegetation Management Work, Risks & Resource Requirements" attached as Appendix E to API's Distribution System Plan (Exhibit 2/Tab 3/Sch. 1/Appendix A) provides significant analysis in support of the expanded vegetation program. Specifically, Exhibit 11-56 on page 78 of this report shows the compounding cumulative liability associated with underfunding the program.

b) API is not forecasting an outage cost savings from this program, but rather is targeting a sustainable vegetation management program that will avoid the incremental costs associated with an increasing number of tree-caused outages that would result from continuing at traditional vegetation management spending levels. Section 11 (page 73) of the report referenced in part a) details the risk of underfunding the vegetation management program.

c) See part b).

(page left blank intentionally)

4.0-VECC-20

Reference E4/T1/S1/Appendix B

a) At page 12 of Appendix B it lists $178k in estimated savings as part of the SCADA program. Are these savings incorporated into the 2015 OM&A forecast?
b) Please provide the cost-benefit analysis that was undertaken in support of the SCADA project.

RESPONSE:

a) Please refer to 2-Staff-11(d) for a description of how the estimated savings have been incorporated into both capital and maintenance program costs.

b) Please refer to the attached "SCADA System Business Case for Algoma Power Inc."

(page left blank intentionally)

May 7th, 2014

SCADA System Business Case for Algoma Power Inc.

Util-Assist Inc.
www.util-assist.com

355 Harry Walker Parkway North, Unit 4
Newmarket, ON L3Y 7B3
t. 905.952.0477
f. 905.952.3479

util-assist Solutions. Simplified.

Table of Contents

Section 1.0: Executive Summary

Significant technological advancements have been made in recent years which are contributing to ever more cost-effective solutions for utilities. The Smart Meter Initiative in Ontario has resulted in the implementation of enabling technology—technology that can be incorporated into Smart Grid strategies. While Algoma Power Inc. (API) is challenged to provide service reliability to the same degree as other Ontario utilities given their rural and relatively unpopulated service territory, the technology available today and the communication medium that exists across the API territory as a result of the implementation of smart meters provide an opportunity for API to begin closing the gap in Key Performance Indicators (such as the System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI)). These indices are all monitored on an annual basis by the regulators, and the challenges that API are faced with are reflected in the reported numbers.

This report provides API with a go-forward strategy and business case information to justify the costs associated with upgraded technological solutions that will complement the existing Supervisory Control and Data Acquisition (SCADA) system.

A phased approach to the implementation of technology is proposed which will include leveraging the existing AMI network as a communication solution for SCADA devices. Prior to the implementation of the AMI network, robust communication solutions simply did not exist across the API territory, introducing the need for expensive satellite communications or the possibility of multiple contracts with varied cell solution providers due to the less than comprehensive coverage that exists across the full service territory. The costs—both from a technology and administrative perspective—have resulted in difficulty creating a positive business case. The proposed phased approach includes a proof of concept phase to demonstrate the viability of the AMI network in providing a communication solution. In subsequent phases, technology is deployed to monitor and control devices on the API network which will result in improved service for API's customers.

To develop the business case, API completed a full analysis of their outage statistics to determine interruption cost estimates and the estimated value of reliability improvements. API also quantified benefits related to savings in operations, maintenance, engineering and the after-hours call centre. In addition to these quantifiable benefits, unquantifiable benefits were considered in order to fully leverage the SCADA system. These unquantifiable opportunities combined amount to significant additional benefits. The business case is based on 15 years, which is the typical useful life span for SCADA devices. The analysis shows an internal rate of return of 21.03% (18.66% based on NPV), with a payback period of just over 8 years.

Section 2.0: Introduction (Vision and Business Drivers)

Algoma Power Inc. (API) has purchased a SCADA master station from Survalent Technology. The purpose of this business case is to validate a long-term SCADA implementation strategy. Opportunities include utilization of the existing AMI network to provide communication across the service territory and the installation of additional SCADA-capable devices to allow improved monitoring and control within API's remote areas. By identifying and prioritizing the opportunities, API can embark upon the strategy with confidence that the model is cost-justified and that the expected benefits will be tangible, leading to improved statistics for reliability.

2.1 Regulatory Requirements

The Ontario Energy Board (OEB) utilizes a "renewed regulatory framework for electricity" which provides "alignment between a sustainable, financially viable electricity section and the expectations of customers for reliable service at a reasonable price." The OEB has used this approach because it considers that "emphasizing results rather than activities will better respond to customer preferences, enhance distributor productivity and promote innovation."[1]

With regards to setting rates, the OEB has asked distributors to file five-year capital plans to support their rate applications. This five-year SCADA plan will support this goal by providing API with documentation to support their planned capital expenditures for SCADA technology. SCADA technology is a critical consideration, as it is enabling technology for multiple objectives that the OEB have used to guide their policy development. As listed in the OEB Act,[2] objectives include:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
4. To facilitate the implementation of a smart grid in Ontario.
5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

With objectives that include promoting conservation and demand management, the implementation of a Smart Grid, and the promotion of renewable energy, there are opportunities to leverage the existing smart meter network to cost-effectively implement SCADA technology to accomplish these objectives.

[1] The "Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012" is referenced within this introductory paragraph

[2] *Ontario Energy Board Act, 1998* (the "OEB Act")

2.1.1 The Ontario Smart Grid Mandate

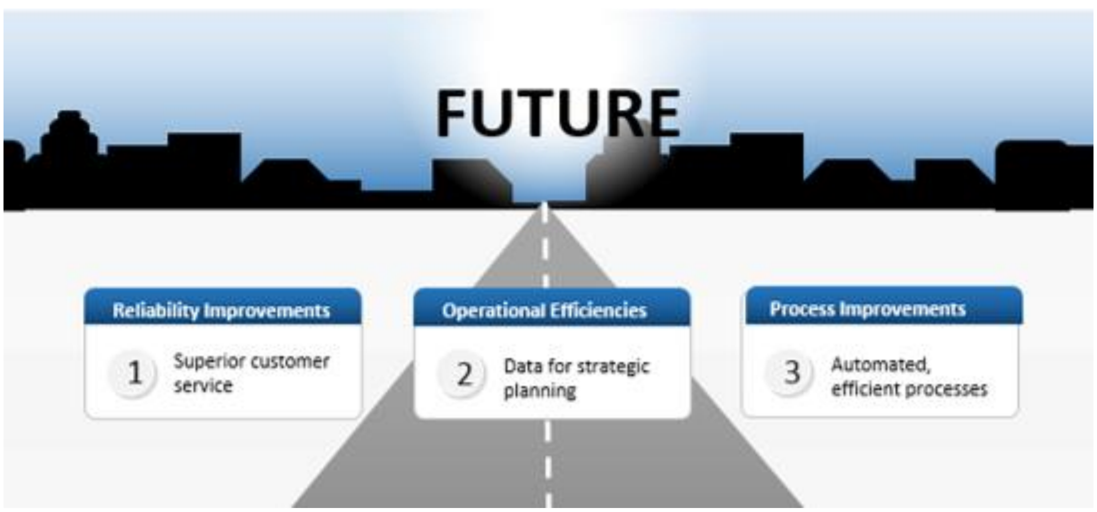
The Ontario Electricity Act (subsection 2(1.3)) defines smart grid as the "advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of,

> (a) enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;
>
> (b) expanding opportunities to provide demand response, price information and load control to electricity customers;
>
> (c) accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or
>
> (d) supporting other objectives that may be prescribed by regulation."

The Ontario Energy Board (OEB) sets out high level expectations with respect to smart grid activities that electricity distributors should consider when developing investment plans. With respect to (c), above, the OEB's Supplemental Report on Smart Grid (February 11, 2013) states that: "Regulated entities must demonstrate in their investment plans that they have investigated opportunities for operational efficiencies and improved asset management, enabled by more and better data provided by smart grid technology."

2.2 API's Vision

One of API's strategic objectives is to meet Ontario's mandate for smart grid development by focusing on reliability improvements, operational efficiencies, and process improvements. API considers that investments in SCADA and other business systems to be a critical first step in this regard.



API envisions a SCADA strategy that delivers the greatest reliability improvements, operational efficiencies and process improvements at the lowest possible cost.

2.3 An Introduction to SCADA

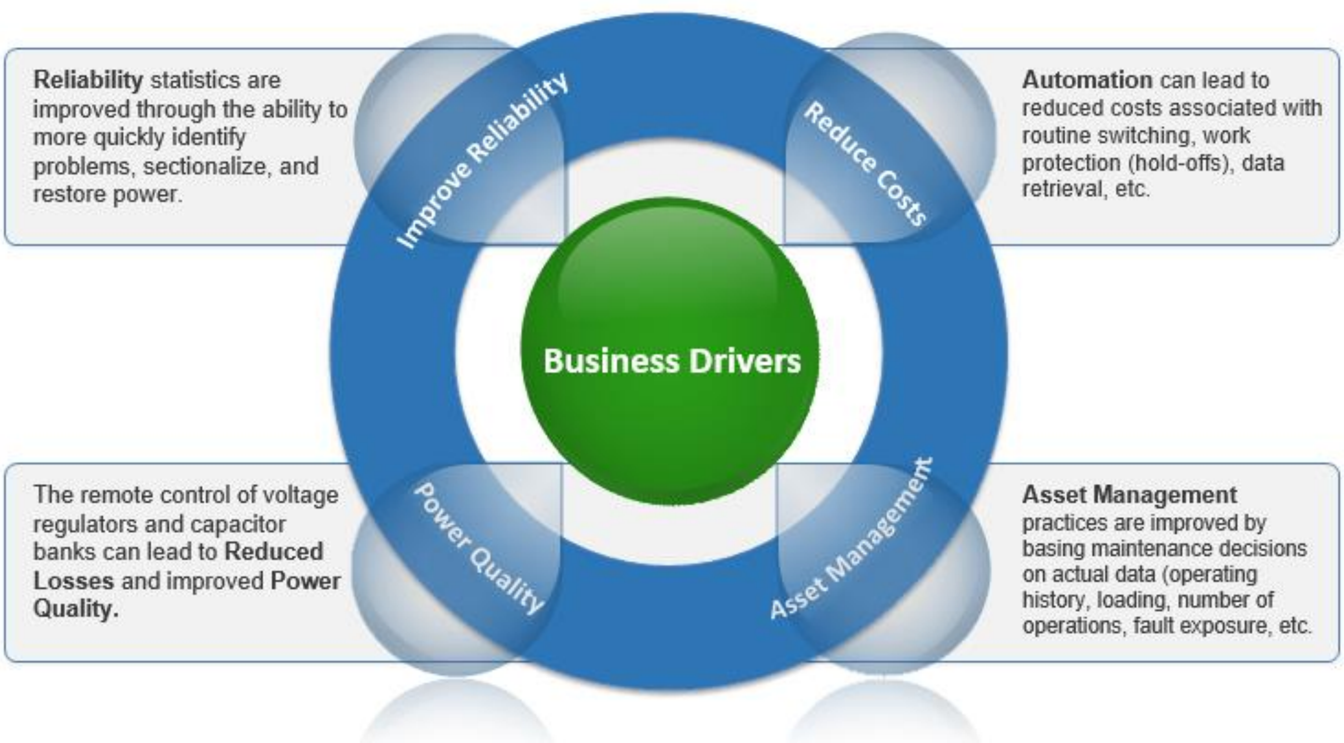
A Supervisory Control and Data Acquisition (SCADA) system provides sensing, monitoring and control capabilities to track operations and exchange data from remote locations. SCADA system are used in operations that require real-time information, and most control occurs automatically with override functionality through operator intervention. A SCADA system consists of four key components:

1. A master system that collects the data and controls the processes
2. Remote telemetry units (RTUs) that serve as local collection points for collecting data from the sensors and delivering it to the master system. An RTU contains a central processor, a set of input/output modules and communication ports to connect to field devices.
3. Field sensors and devices that monitor and control process equipment
4. The communication network that connects all parts of the system

SCADA systems are used by many different industries, such as manufacturing, oil and gas, transit, and electric and water utilities. Electric utilities use SCADA systems to monitor circuit breakers, identify current flow and line voltage, and to switch sections of the power grid on and off. Line sensors send data back to the master system where it is analyzed in real-time to automatically make decisions and execute actions to regulate voltage levels and resolve any disruption issues.

2.4 Business Drivers for a SCADA Implementation

API's key business drivers for a SCADA implementation project are as follows:



Improving service reliability requires a multi-faceted approach. Prevention of power-related problems is the best case scenario of course, and technology can contribute by allowing real-time visibility and historical tracking of key system attributes leading to improved asset management practices by basing maintenance decisions on actual operating history. Information that leads to replacing or maintaining assets prior to complete failure will prevent outages and reduce costs – when expensive assets fail completely the repair requirements can far exceed more straightforward maintenance.

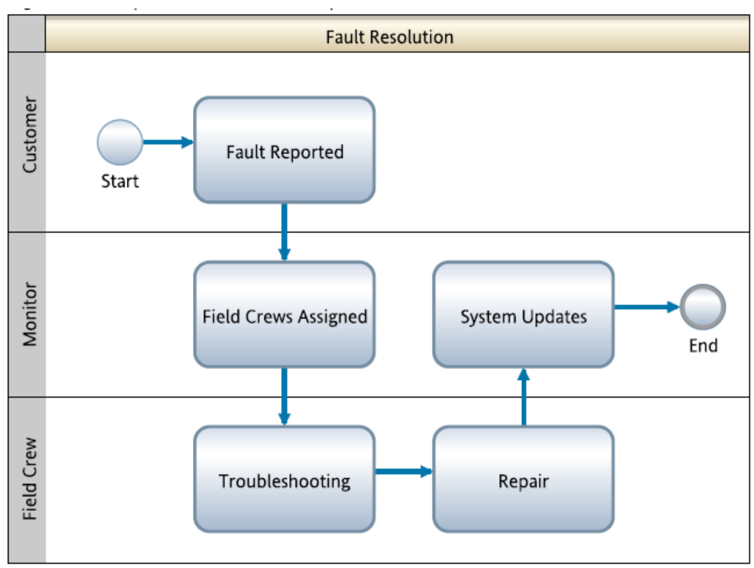
Moving beyond prevention, when problems do occur, an improved ability to isolate problems and restore power will also have positive impacts on service reliability indicators. The ability to remotely monitor devices, such as switches and fault indicators, will improve API's ability to isolate problems and deploy field crews. When problems have been isolated, it is possible – through the implementation of SCADA capable devices – to sectionalize and transfer load, leading to reduced times for power restoration.

Section 3.0 Background

3.1 Current Business Process

API's current business process for addressing faults is as follows.

1. A customer or API crew or third-party observers in the field report a fault (or faults).
2. A call ticket is logged in the electronic call ticket management system by a member of API's customer service department.
3. The monitor of the call ticket management system contacts the crew in the proximity of the problem and passes along relevant information.
4. The crew travels to the site. Travel time can be lengthy, particularly after hours when there are minimal crews available.
5. The crew investigates the fault and determines the course of action.
6. The crew may elect to perform manual switching to sectionalize a restoration, particularly in the more populous regions. In some areas, with only one crew available after hours, switching is not feasible due to the driving time required, and it is faster to complete a full restoration.



7. The crew repairs the fault.
8. At the end of the day (or the next morning), the crew submits an Interruption Report with the details of the problem and the action taken to resolve the issue.
9. The monitor of the call ticket management system updates the ticket with the information from the report and closes the ticket.
10. The Interruption Report is filed electronically and physically.

3.2 Gap Analysis

The high level business process presented above is not dramatically different from many Ontario utilities, with the exception of the process used by utilities that have implemented technology-related changes. Utilities without significant quantities of SCADA devices still depend (to a large degree) on customers for notification of issues and use manual processes for locating and resolving issues.

While API is not alone among utilities that depend on customer reporting to understand that problems have occurred, the combination of a large service territory and a relatively low concentration of customers creates a (current) requirement for a highly manual process to locate and identify the cause of outages. Determining the nature and location of problems requires visual inspection combined with what amounts to educated guesswork.

In reviewing the high level business process then, the most significant finding of a "gap analysis" is the extent of the impact which manual investigation[3] has on the service reliability indices for API. If API can implement SCADA devices to ease the process of identifying issues in the field, service reliability will improve.

3.2.1 Key Performance Indicators (KPIs) for Service Reliability

What does SAIDI represent?

- The average outage duration for each customer served. SAIDI is measured in units of time, often minutes or hours.
- The median value for North American utilities is approximately 1.50 hours.

What does SAIFI represent?

- The average number of interruptions that a customer would experience, measured in units of interruptions per customer.
- The median value for North American utilities is approximately 1.10 interruptions per customer.

What does CAIDI represent?

- CAIDI is the Customer Average Interruption Duration Index; the average outage duration that any given customer would experience. CAIDI can also be viewed as the average restoration time.

Are there other service reliability indices?

- CAIFI is the average interruption frequency index, designed to show trends in customers interrupted and helps to show the number of customers affected out of the whole customer base.
- MAIFI is a measure of momentary outages.

What are Ontario utilities regulated to monitor?

- Ontario utilities are required to measure and report upon SAIDI, SAIFI and CAIDI. For this reason, the remainder of this report will only consider and compare the SAIDI, SAIFI and CAIDI statistics of API and other utilities.

3.2.2 API's Service Territory and Reliability KPIs

What makes API somewhat distinctive is the nature of their service territory and the impact on the KPIs that regulators use to monitor service reliability. For example, the following charts show the SAIDI, SAIFI, and CAIDI statistics for the utilities with the highest and lowest reliability indices in the province.

[3] For example, traditional line fault indicators drop a flag requiring that field crews drive alongside the electrical lines and look for dropped flags. Travel time can be considerable just to locate the source of the problem. Field crews are dispatched to the general location to investigate the outage and determine the appropriate resolution.

	SAIDI 2010	2011	2012	Average
Hydro One	9.37	22.11	11.29	10.65
Northern Ontario Wires	5.17	7.23	10.49	
Hearst Power	13.87	8.18	8.13	
St. Thomas Energy	0.34	1.72	0.22	0.57
Brantford Power	1.09	0.49	0.30	
Fort Francis	0.60	0.09	0.30	
Algoma Power	16.65	13.69	11.25	13.86

	SAIFI 2010	2011	2012	Average
Hydro One	3.25	4.57	3.68	3.26
Northern Ontario Wires	2.76	1.89	3.27	
Hearst Power	3.10	1.73	5.12	
St. Thomas Energy	0.57	1.69	1.05	0.95
Brantford Power	1.95	1.24	1.23	
Fort Francis	0.31	0.21	0.30	
Algoma Power	4.58	6.55	9.01	6.71

	CAIDI 2010	2011	2012	Average
Hydro One	2.88	4.84	3.07	3.39
Northern Ontario Wires	1.87	3.82	3.21	
Hearst Power	4.47	4.73	1.59	
St. Thomas Energy	0.60	1.02	0.21	0.71
Brantford Power	0.56	0.40	0.26	
Fort Francis	1.92	0.43	1.02	
Algoma Power	3.64	2.09	1.25	2.33

When examining the *system*-related indices for duration and frequency of outages, it is immediately apparent that there is a wide disparity between the utilities with the highest and lowest reliability numbers; in both cases (on average) API has the lower reliability index in the province. With regards to the customer index for frequency of outages, there are years where API's customers experience fewer interruptions in service than some other rural utilities, but again the ranking is among the lowest, and there remains a significant disparity between the utilities with the highest and lowest reliability statistics.

When the service territories of these same utilities are compared, the disparity is evident:

	Rural Service Area (sq km)	Urban Service Area (sq km)	Total Service Area (sq km)	Customers (per sq km)	Customers (per km of Line)
Hydro One	650000	0	650000	1.88	10.32
Northern Ontario Wires	0	28	28	216.71	16.4
Hearst Power	0	93	93	29.97	40.99
St. Thomas Energy	0	33	33	501.91	65.73
Brantford Power	0	74	74	517.03	74.73
Fort Francis	0	26	26	145.38	51.08
Algoma Power	14197	3	14200	0.82	6.28

When looking at the service area characteristics, it is evident why most utilities would not even include Hydro One in a comparison with their utility – the size and rural nature of the territory is unique within the province. It is included in this comparison to help illustrate some of the challenges that API also experiences. The other utilities with low reliability indices have only urban service territories, with a significant contributor to their low reliability being loss of supply outages.

What the chart effectively demonstrates is that API has the lowest customers per square kilometre in the province and the fewest customers per kilometre of supply line. For a utility that uses very little automation to monitor their plant, there are also very few customers spread out across their territory acting as the “eyes and ears” of the utility during outage situations. In more urban locations, many customers may call in to report problems, allowing the utility to quickly analyze – based on the electrical connectivity model – the approximate source of the outage. But for API, with few customers and long service lines, this manual process is more complicated, requiring that field crews manually locate the root cause. With delays in the location of the source, the overall time required to restore outages quickly increases, negatively impacting KPIs. This presents an opportunity for API: automation can more easily and quickly allow field crews to begin resolving problems by pointing them to the source, resulting in a positive impact on statistics.

Section 4.0: Benefits of SCADA Strategy

A SCADA system is a vital tool not only for daily operations, but also for strategic decision making. To harvest the full potential of a SCADA system, a benefit analysis needs to consider both quantifiable and unquantifiable benefits—otherwise opportunities to fully leverage the SCADA system could be overlooked.

Quantifiable benefits of implementing SCADA technology for API include:

- Reduced interruption costs through reliability improvements
- Reduced operations costs
  - Reduction in costs for switching/work protection related to Great Lakes Power Transmission (transmitter) requests for isolation.
  - Reduction in costs for applying hold-offs for API work on or in proximity to live circuits.
  - Reduction in engineering field costs for fault analysis, setting changes, etc.
- Reduced maintenance costs
  - Reduction in 6-year maintenance costs due to legacy reclosers/switches being replaced by new units requiring minimal maintenance.
- Reduced call centre costs
  - Reduction in after-hours call centre costs.

The benefits below, although difficult to accurately quantify, can amount to significant value and savings. To understand the true value of a SCADA project these benefits need to be taken into account. Fortis BC, upon filing their Application for a Distribution Substation Automation Program, identified that improvements in areas such as safety, customer satisfaction and assumed line losses, when combined with quantifiable benefits, would produce either a positive or zero net present value (NPV).

- Reduced losses:
  - Volt/var management for loss reduction.
  - Remote switching to optimize losses.
  - Improved analytics (actual vs. modeled comparison) to identify sources of higher than expected losses.
  - Load balancing between phases based on detailed history rather than "point in time" analysis.
- Improved asset management
  - Improved prediction of asset end of life based on actual operating history
  - Targeted maintenance planning, e.g. moving from time-based to condition-based by relying on number and type of operations, alarms, etc.
  - Immediate indication of critical alarms.
- Customer-focused improvements
  - Quicker restoration following planned and forced outages (reduced travel and setup time by closing the device remotely).
  - Improved ability to communicate outage cause/status/progress information to customers.
  - Improved power quality.
- Policy objectives
  - Renewable Energy enabling.
  - Smart Grid enabling.
  - Enable future conservation voltage reduction and or load-shedding.

- Improved worker safety
  - Safer restoration after repairs/work completed by switching from control center (worker is not in vicinity of device if fault remains on the line).
  - Reduced patrol and travel time during outage events.

The benefits that API can achieve through a SCADA system are outlined in detail below. To help develop this list, Util-Assist interviewed a number of utilities on the benefits that they have realised upon integrating a SCADA system.

4.1 Reduced Interruptions Costs through Reliability Improvements

A SCADA system would result in improvements to SAIDI, SAIFI and CAIDI statistics. Using a calculator published by the U.S. Department of Energy (ICECalculator.com), API was able to estimate the value of reliability improvements using calculations derived from an outage analysis (see *Section 4.1.1: API Outage Analysis*). The City of Medicine Hat noted a significant improvement in their reliability statistics with the introduction of their SCADA system. Likewise, PowerStream referenced similar benefits upon the merger of Barrie Hydro. Barrie Hydro did have a SCADA system, but not 24/7 coverage in the control room. Prior to the merger, Barrie Hydro had a SAIDI of close of three hours (well above the North American median of 1.5 hours). After merging with PowerStream and gaining 24/7 coverage, the SAIDI statistic was reduced to less than an hour. These savings were attributed to being able to respond to unplanned outages after hours.

Both PowerStream and the City of Medicine Hat also specifically identified reclosers, switches and fault circuit indicators (FCIs) as contributing to fewer Customer Minutes of Interruption (CMIs). Reclosers reduce the impact of an outage to just those customers that are downstream of the recloser. As noted by the City of Medicine Hat, many of their faults occur in rural areas, caused by tree contacts or lighting, and reclosers help to isolate urban customers from these faults.

Fewer and shorter outages would ultimately result in greater customer satisfaction for API's customers. Furthermore, with a self-healing grid, power re-routing can often take place immediately without customers even knowing about a problem. A recloser can automatically close a faulty supply and seamlessly restore an alternative source, resulting in a continuous flow of electricity to the customer. With a SCADA system, API would have the ability to detect and analyze problems and use this data to proactively prevent outages by making adjustments and corrections. Furthermore, any outages that do occur will be shorter in duration (see *Section 4.7.1: Faster Power Restoration*).

4.1.1 API Outage Analysis

API recently conducted an outage analysis to identify specific causes of the outages and identify possible remediation activities (see Appendix A for the complete study). The most significant cause was related to falling and interfering trees, and consequently API initiated a vegetation management program, which is expected to assist greatly with reliability improvements. In addition to the benefits in terms of locating and restoring future tree-related outages, many of the other causes could have been eliminated or mitigated with a SCADA system and devices, as outlined in the table below. Analysis of historical outages revealed that for many causes such as insulator failure or conductor damage, a relatively small percentage of the total number of outages occurred on express feeders, but that these events had a disproportionate impact on reliability statistics due to the configuration of API's system. Prioritization of integrating express feeder SCADA devices to a control room would be expected to reduce both the number of affected customers and the restoration times associated with these types of express feeder outages.

API Outage Analysis		
Cause	**Analysis**	**How SCADA and SCADA Devices Could Have Helped**
Failed insulator	~90% of impact on East of Sault 34.5kV	SAIFI/SAIDI impact could have been drastically reduced with additional protective devices and/or SCADA control. Integration of existing SCADA-capable devices and installation of additional SCADA-capable devices would be expected to improve future reliability (SAIFI and SAIDI) Many similar future outages could be avoided by installing additional devices and integrating them to SCADA to take advantage of existing looped configurations.
Failed recloser	All failures are related to older oil-filled reclosers. Failure rates are expected to decline with changes in framing standards and equipment type as a result of ongoing capital end-of-life replacement programs.	Vacuum-interrupting, solid insulation reclosers would have mitigated the problem Replacing existing fuses and reclosers with vacuum interrupting reclosers (even without SCADA integration) would be expected to improve future reliability (SAIFI and SAIDI) by preventing transient faults from becoming permanent. SCADA integration of these devices would have further SAIDI benefits in the form of reduced restoration times when permanent faults do occur.
Lightning Caused Distribution Line Outage/Damage	Mostly blown fuses during lightning	Reclosers would have eliminated a large portion of the outages. Replacing existing fuses and reclosers with vacuum interrupting reclosers (even without SCADA integration) would be expected to improve future reliability (SAIFI and SAIDI) by preventing transient faults from becoming permanent. SCADA integration of these devices would have further SAIDI benefits in the form of reduced restoration times when permanent faults do occur.
Blown fuse on transient fault		Reclosers would have eliminated a large portion of the outages. Replacing existing fuses and reclosers with vacuum interrupting reclosers (even without SCADA integration) would be expected to improve future reliability (SAIFI and SAIDI) by preventing transient faults from becoming permanent. SCADA integration of these devices would have further SAIDI benefits in the form of reduced restoration times when permanent faults do occur.

API Outage Analysis		
Cause	**Analysis**	**How SCADA and SCADA Devices Could Have Helped**
Floating Phase	About half of the SAIDI impact was due to a single pole fire on the East of Sault 34.5	Impact could have been reduced with additional protective devices and/or SCADA control Integration of existing SCADA-capable devices and installation of additional SCADA-capable devices would be expected to improve future reliability (SAIFI and SAIDI) Many similar future outages could be avoided by installing additional devices and integrating them to SCADA to take advantage of existing looped configurations.
Failed/damaged conductor	Approximately 1/3 is on No. 4 Cct beyond Hawk Junction.	Additional protective devices and FCIs would have reduced the number of customers affected and restoration time. Integration of existing SCADA-capable devices and installation of additional SCADA-capable devices would be expected to improve future reliability (SAIFI and SAIDI) Additional protective devices and FCI would limit the number of customers affected by this type of outage, and would reduce the duration by better directing crews to the location of the fault.
Failed switch	Most of impact is failed porcelain fused cutouts on laterals feeding large number of customers.	Replacement of main-line fuses with reclosers would avoid a large portion of the outages. Replacing existing fuses and reclosers with vacuum interrupting reclosers (even without SCADA integration) would be expected to improve future reliability (SAIFI and SAIDI) by preventing transient faults from becoming permanent. SCADA integration of these devices would have further SAIDI benefits in the form of reduced restoration times when permanent faults do occur.

4.2 Reduced Operations Costs

4.2.1 Reduced Field and Engineering Costs

API is expected to be able to cut labour costs by replacing current manual procedures with automated operations. SCADA can eliminate the need for field staff to visit sites for inspection, data collection and device adjustments. Similarly, with the ability to control devices remotely, API would experience savings in any switching or hold-off scenarios. API receives regular requests for isolation from Great Lakes Power Transmission (GLPT). API also applies hold-offs for their own work or other work being conducted in proximity to live circuits (e.g., forestry work, live-line work). PowerStream noted that once Barrie Hydro merged with PowerStream and gained a 24/7 control room, after-hours visits to substations to close circuit breakers dropped significantly as this work is now done remotely.

4.2.2 Reduced Troubleshooting Time

Real-time troubleshooting also reduces the number of hours required to resolve problems, freeing up staff to apply their skill sets to other areas of the organization. A SCADA system delivers a real-time view into operations, providing the ability to optimize the system for maximum efficiency. With alarms and system-wide monitoring, API will be able to address problems immediately with a SCADA system.

4.2.3 Automated Data Collection

A SCADA system would eliminate any API requirements for manual data collection. In the City of Medicine Hat's case, the utility typically used to send out a truck once a month to drive around the service territory and collect data that was then entered into a spreadsheet. This information is now available in real-time for analysis, leading to a comprehensive asset management plan.

4.3 Reduced Maintenance Costs

The system automation of a SCADA system would provide API with direct cost savings with respect to maintenance costs. A self-healing system automatically resolves disruptions, greatly reducing the time and costs associated with manual adjustments. The availability of accurate data for improved system diagnostics would also contribute to reduced maintenance expenditures.

Moreover, by implementing a SCADA system and devices, API would also be able to increase the life of various equipment. For example, the City of Medicine Hat was able to extend the life of their breakers. Each breaker has a counter, and after so many "counts," the breaker requires maintenance. By reducing the number of breaker trips, the City of Medicine Hat has prolonged the operational life of these expensive assets. With legacy reclosers and switches being replaced by new units that require minimum maintenance, API will definitely see reduced maintenance costs for these new devices.

4.4 Reduced Call Centre Costs

In implementing the SCADA system, control will be maintained centrally by CNPI with 24/7 coverage. This approach eliminates the after-hours call centre costs currently incurred by API.

4.5 Loss Reduction

4.5.1 Volt/Var Management

Savings due to better volt/var management are based on improved analysis and adjustment to improve device settings. Volt/var optimization maximizes efficiency by controlling a variety of devices (such as capacitors and voltage regulators) to reduce system losses while keeping customer voltage levels within allowable ranges. This reduces the risk of large voltage variations which could damage consumer devices, such as pricy personal electronics and electric vehicles. Using traditional methods, the difficulty in minimizing system losses using devices such as capacitors is maintaining acceptable voltages during all system loading conditions. Even with smart meter data, utilities are not able to reduce system losses to the most efficient level.

To achieve volt/var optimization, usage must be monitored continuously and be reported in real-time. With a SCADA system, API will be able to analyze a steady stream of data and be able to make automatic adjustments to capacitor banks and regulators to reduce system losses without negative voltage impacts.

4.5.2 Remote Switching to Optimize Losses

With data from SCADA devices, API will have the ability to analyze distribution lines to determine where voltage levels are lowest. Remote switching can then occur to create alternative paths from feeders, thereby reducing losses. As more and more devices are deployed, API will gather increasing accurate information that can be combined with smart meter data to determine where to install additional devices to optimize losses even further.

4.5.3 Improved Analytics

A SCADA system would provide API with a powerful tool for data analysis. The data is available in real-time to promote decision-making with respect to maintaining power system parameters. Moreover, graphical interfaces and dashboards help to streamline analysis. The improved analytics can help identify sources of higher than expected losses by comparing an actual vs. a modeled comparison.

4.5.4 Load Balancing and Evaluation of Capacity Utilization

An exact evaluation of the capacity utilization of distribution assets is complicated by the fact that API has little data available on the exact loading of individual distribution stations or feeders. Historically, API's station configuration consisted of simple layouts with no metering or SCADA-capable devices. There were also few, if any, SCADA-capable devices on any distribution feeders. As a result, API's current process for capacity evaluation and load balancing between phases relies on load allocation algorithms in engineering analysis software. These algorithms allocate the known load at an upstream delivery point to various locations on API's system based on options such as the number of downstream customers, the total capacity of downstream pole-top transformers, etc. The results are approximations of actual loading. With the exact load data available through a SCADA system, API will be able to balance load between phases to minimize losses, as well as assess asset capacity utilization based on detailed history rather than on a "point in time" analysis.

4.6 Improved Asset Management

4.6.1 Maintenance Planning

Accurate and timely maintenance information can lead to the prevention of power-related problems: equipment can be repaired or replaced prior to a malfunction that results in an outage. Historical data can also be used to improve efficiency—the data can highlight areas for improvement and proactively identify future problems. For example, a trend of equipment issues can alert the operator that targeted maintenance is required. The historical data can ultimately be used to develop an asset management plan that is based on accurate operating history.

The information provided by SCADA can be used to improved overall inspection and maintenance programs, such as to move from a time-based to a condition-based program that relies on the number and type of operations, alarms, etc. In this way, API will be able to develop improved predictions of asset end-of-life that is based on actual operating history.

4.6.2 Design Efficiencies

The additional asset management information available with a SCADA system would help in efficiencies in the conceptual and detailed design processes.

4.6.3 Immediate Critical Alarms

The SCADA technology would provide visibility of critical alarms in real-time, allowing for rapid resolution and repair of assets. For Fortis BC, alarms was included as a justification for SCADA. It was only during regular substation inspections that the utility could identify equipment failures, such as chargers. With SCADA this information is readily available, also providing an added safety alert for dangers such as a high temperatures or low oil.

4.7 Customer-Focused Benefits

4.7.1 Faster Power Restoration

A SCADA system would help API minimize disruptions since automated processes would be faster and more consistent than the current manual processes. An FCI would be able to notify API immediately when a disruption occurs. As well, by identifying the exact location of an outage, without having to wait for a customer to call, the SCADA system would be able to direct crews immediately to the problem area, ultimately saving time in getting the power restored. If one FCI detects a fault on a line but another does not, API will be able to pinpoint exactly where the fault is located. This information will also make for easier dispatching—API will have the information available to make decisions on the number of field staff required and the exact geographic location to which to send them. Feedback from FCIs will be particularly useful where a recloser protects either a very long section of line or protects multiple line segments that branch off in various directions. Increased deployment of automatic reclosers on portions of API's system with looped supplies would be able to isolate an outage to a smaller area.

Most faults are of a transient nature which can be successfully cleared with reclosers. Faults of a longer duration can also be significantly shortened with the devices. In Pennsylvania, PECO, the largest electric and natural gas utility in the state, has been upgrading their grid with reclosers in order to improve performance for their customers. To date, over 1500 reclosers have been installed, greatly reducing the number of lengthy service interruptions. For example, in Hatfield, Towamencin, Montgomery and Upper Gwynedd townships, the new reclosers prevented approximately 759,000 sustained service interruptions to PECO customers in 2013.[4]

The following diagrams illustrate the reduced time in restoring power to unaffected customers. The first graphic shows a timeline for power restoral without a SCADA system. As a start, time is expended between the time of the fault and the time that the customer calls to report the outage. For API, this time can vary greatly: in urban areas, customers may call almost immediately, while in rural areas with seasonal dwellings, outages may not be reported for hours or even days. The typical timeline also includes time to travel: during normal business hours, this is typically 30 to 60 minutes (unless there are multiple concurrent events). However, after hours, this timeframe can increase to 1.5 to 2 hours in the Batchawana to west of Thessalon area—only two people are typically on call to service this vast region. Once arriving at the site location, field staff normally take another 15 to 20 minutes to investigate the fault.

Manual switching, where possible, takes a few more minutes. Note, however, that in the vast majority of situations, API does not have the option to sectionalize a restoration—the outage occurs from the last device upstream of the issue. Moreover, because of manual switches and only one crew after hours, the driving time required to switch the system for partial restoration is comparable to the repair time for full restoration. There are populous areas, however (such as the East of Sault and Wawa 34.5 kV systems) where alternative supplies are available for switching.

[4] The Reporter Electric Utilities, "PECO working to install reclosers on power lines to cut down on outages in area." http://www.thereporteronline.com/business/20140206/peco-working-to-install-reclosers-on-power-lines-to-cut-down-on-outages-in-area

Finally, the repair timeframe varies according to the nature of the problem. A typical timeframe is 1 to 2 hours There are situations, however, where repair times could exceed 4 hours (for example, storms causing multiple trees falling into lines in a given area, broken poles requiring travel to work centres to load poles and return to the site of the outage).

In contrast, with SCADA in place (see second diagram, below), power can be restored to unaffected customers even before the first phone call from a customer.

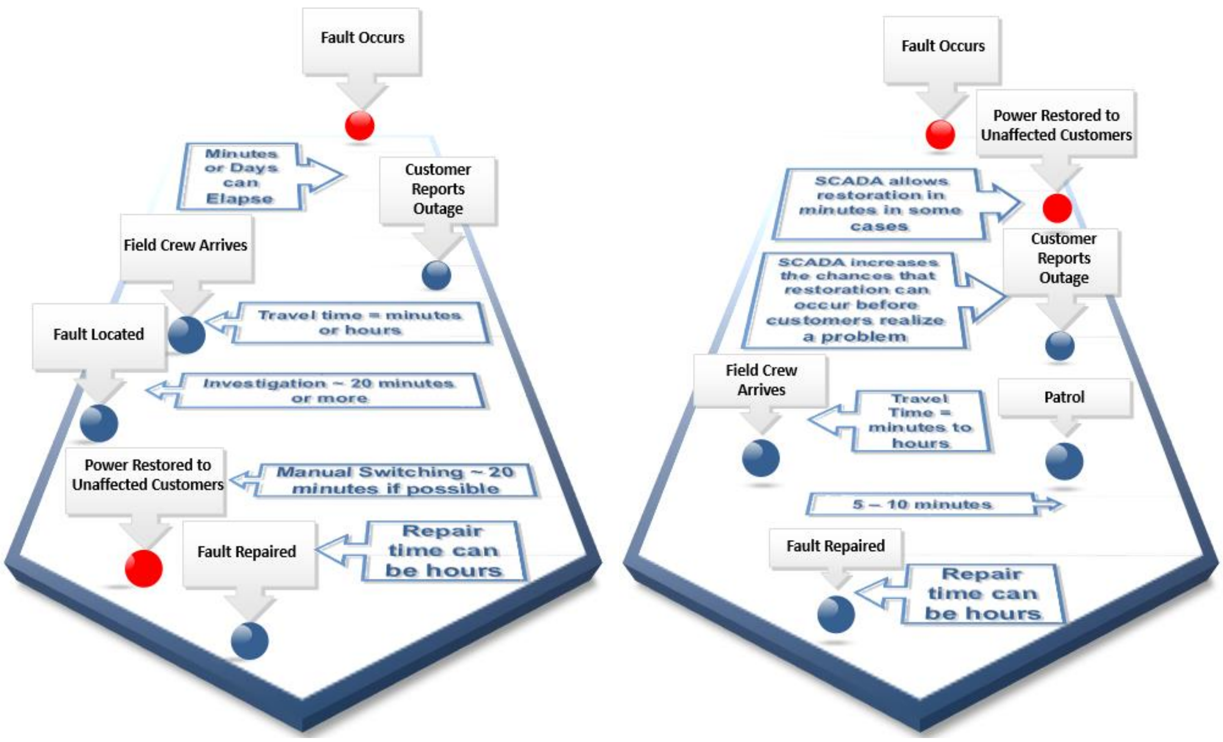


Figure 1: Restoration Timelines without and with SCADA

4.7.2 Improved Communication re Power Events

With real-time identification of power outages through SCADA, API would have an improved ability to communicate power events with customers. This includes outage cause as well as status/progress information. Customers appreciate being are continually updated on the status of outages, especially the estimated restoration time.

4.7.3 Improved Power Quality

Increased customer satisfaction can also derive from meeting power quality requirements (see *Section 4.5.1: Volt/Var Management*).

4.8 Policy Objectives

4.8.1 Renewable Energy Enabling

In *Section 2.1: Regulatory Requirements*, it was noted that one of the OEB's objectives is to "promote the use and generation of electricity from renewable energy sources." A difficult function related to distributed generation – of which renewables form a huge part – is the management of the grid at the point where the generation facility joins the distribution system. A SCADA system provides automated switches to disconnect during outages when the generation facility is still producing power and then reconnect when power has been restored.

4.8.2 Smart Grid Enabling

The term "smart grid" loosely refers to the use of information to act in an automated way to improve the distribution of electricity. The implementation of smart meters moved Ontario utilities towards a smarter grid by allowing them to better understand how consumers were using electricity. With the implementation of SCADA devices, the utility will have a much improved understanding of how distribution assets are being used. In the big picture, a smart grid is enabled by SCADA allowing the automated optimization of the entire infrastructure, extending well beyond meter reading. With a SCADA implementation, API can enhance their electrical system and work towards meeting Ontario's mandate for smart grid development: as stated in *Section 2.1: Regulatory Requirements,* OEB objectives include "to facilitate the implementation of a smart grid in Ontario."

4.8.3 Enable Future Programs

Having SCADA technology in place would enable future conservation voltage reduction or load-shedding schemes for response to system-wide capacity issues. Overall, a SCADA system provides advanced capability and flexibility to respond to changes in the industry as driven by regulators, customers and owners. In this way API can remain competitive into the future.

4.9 Worker Safety Benefits

4.9.1 Safer Working Conditions

Automation protects workers by enabling remote control of outage management. In fact, safer working conditions was one of the primary drivers for the City of Medicine Hat's SCADA system. The utility cited safety concerns with arc flashing when closing breakers. (An arc flash occurs when a current passes through the air without sufficient insulation between electrified conductors to withstand the voltage. The result is an explosion of intense light, extreme heat (up to 19000ºC) and molten metals, causing severe burns and even eyesight damage and hearing loss.)

4.9.2 Reduced Patrol/Travel Time

With a large, isolated territory, it is a significant benefit that a SCADA implementation would reduce travel times for switching and other activities. API staff will gain safety benefits from fewer field visits to remote and distant areas. As an added benefit, it is expected that API will contribute to a reduction of greenhouse gases emitted from utility vehicles.

Section 5.0: Challenges for SCADA Strategy

Section 4 introduces the benefits that utilities commonly realize through the implementation of SCADA networks. Alongside the common benefits, this document discusses the findings of an API study which demonstrates how actual outage scenarios could have been improved had a SCADA network already been introduced. The benefits of SCADA - particularly for a rural service territory such as API – are clear. This begs the question of why a more advanced network has not previously been installed.

The challenges that the rural API territory present in the restoration of outages are the same challenges faced by telecom providers in deploying a robust communication network. Utilities in southern Ontario have been able to cost-effectively deploy SCADA due to the availability of robust communication platforms from multiple service providers. This has not been the case for API; until recently a communication platform that extended across the service territory was simply not available. The following maps demonstrate what is currently available from the major telecom providers, as compared to the API service territory.

5.1 Communication Technology Service Providers

There is limited availability of third-party communications (cell, POTS, etc.) in much of API's service area. Where communications are available, API has often found the reliability to be less than ideal and/or the ongoing costs to be high.

Coverage maps for the major carriers in the area are provided below.

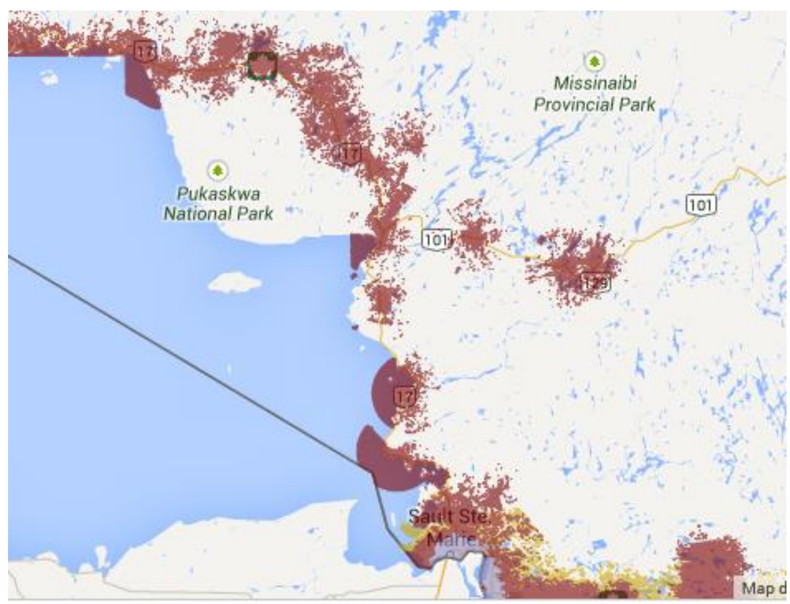


Figure 2: Rogers Communication Coverage

Given the number of customers in API's territory, and the cost of network infrastructure, it is not surprising that coverage tends to be concentrated around common travel routes and population centres.

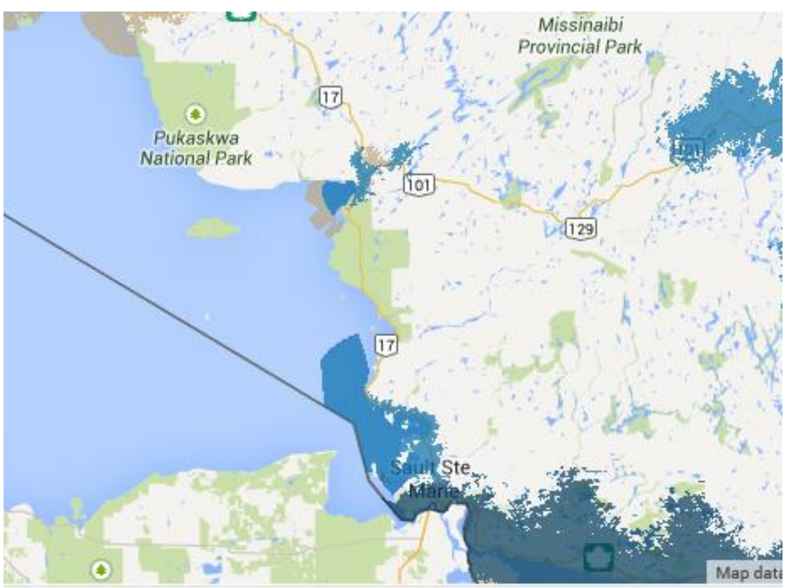


Figure 3: Bell Cellular Coverage

When the coverage maps are compared to the service territory (see next section), it becomes obvious there are vast sections of API's territory without coverage by any major telecom provider.

Figure 4: TBayTel (Thunder Bay Telecom) Coverage

Previous experience indicates that carriers may in some cases overstate the available coverage as displayed on the maps. This may be due to the maps illustrating planned future coverage which is often delayed, relocated or cancelled in these remote northern areas.

Figure 5: Telus Coverage

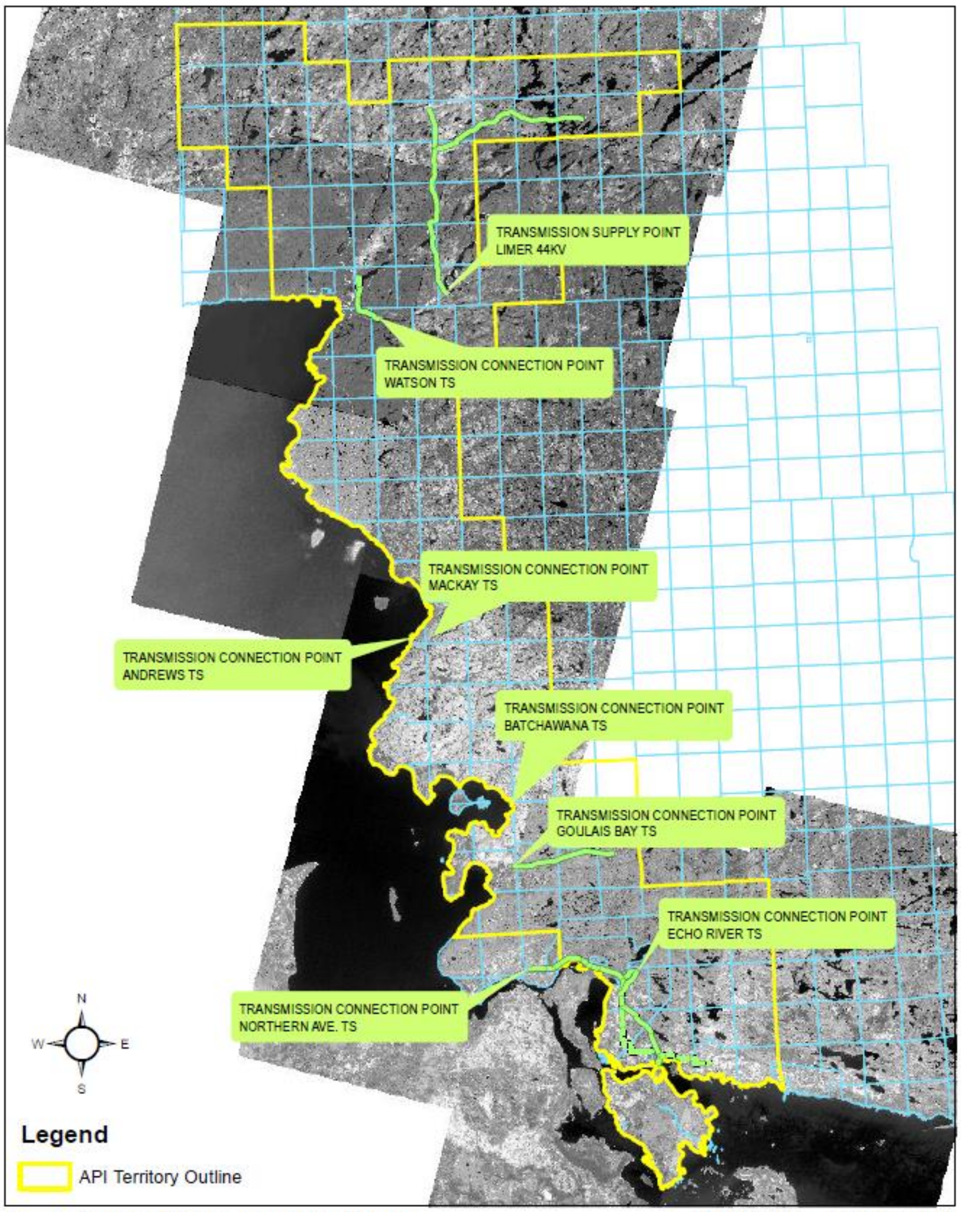
5.2 Service Territory Map

Some background information was provided in a previous section, but is repeated here due to the applicability when comparing service coverage maps of the major telecom providers to the API service territory.

API serves approximately 11,700 customers, ranging from seasonal dwellings with almost zero consumption to large industrial customers with peak demand in excess of 6 MW. With less than 1% of the area considered "urban," the average customer density is 6.3 customers per kilometre of line, which is the lowest in Ontario. With a vast service territory and a low population density, API requires a customized approach to a SCADA implementation. Challenges due to the nature of the service territory include the following:

- The service area is mostly located in Canadian Shield with significant vegetation, rock and changes in elevation. Any technologies relying on wireless communication need to take this into consideration.

- API's system consists of long, single-phase, overhead radial lines. There are a few normally-open tie points on the 34.5 kV sub-transmission systems that would be ideal candidates for the addition of SCADA-capable devices and auto-transfer schemes. API uses a wide range of voltages in various areas (anywhere from 2.4 to 44 kV).
- API's long radial lines require the use of a large number of protective devices between the source substation and the end of the line. This creates occasional challenges with coordination between devices. It also presents a considerable cost challenge when considering the number of devices to integrate to SCADA.



ALGOMA POWER SERVICE AREA

1 Centimeter = 11,000 Meters

5.3 Comparison of Communication Mediums

The following table compares communication mediums by factors for consideration in a SCADA implementation.

Factor	AMI	Cellular	MESH	POTS	Satellite	Unlicensed Wireless	Fibre
Coverage (current)	Hi	Med-Lo	None	Med	Hi	None	None
Latency	Hi	Lo	Med	Lo	Med	Med	Very Lo
Security Risk	Lo	Med	Med-Lo	Med	Med-Lo	Med	Lo
Reliability Risk	Lo	Lo	Lo	Med	Med	Med	Lo
API Ability to Troubleshoot/Repair	Hi	Lo	Med	Lo	Lo	Med	Med
Cost (Initial + Ongoing)	Lo	Med	Med	Med	Hi	Lo	Hi

As a start, comprehensive and reliable communications is compulsory for a SCADA implementation. As shown in the table, existing communications in terms of cellular and POTS are not readily available (see *Section 5.1: Communication Technology Service Providers*). API does offer a licensed Motorola MotoTRBO system, but it is designed for voice and limited text messaging. Although a MESH solution is cost-effective for suburban areas, a MESH solution is not a viable option for API due to the rural nature of the territory: there is insufficient concentration of lines and devices to support communication hops. Similarly, fibre, often an option for substation communications in urban areas, is not available in API's service rural territory. Satellite, although available for API use, is simply not a cost-effective solution.

5.4 The Opportunity Provided by the AMI Network

With the deployment of the Advanced Metering Infrastructure (AMI) network in recent years, API is presented with an opportunity previously unavailable. A communication medium now exists upon which API could conceivably construct a SCADA network, making the advantages discussed in previous sections a possibility for API.

Sensus customers both inside and outside the province have begun to install devices on the AMI network which can communicate with SCADA devices. Because API's AMI network has been deployed such that communication with meters at almost every service location (i.e., customer premise) is possible and has been demonstrated as stable and reliable,[5] the possibility of using this network to enable SCADA communication to devices across much of the same territory has now become feasible.

A strategy which includes leveraging the AMI network is worth exploring. The AMI network was a significant expense for the utility, and in API's case, achieving sufficient coverage for TOU billing resulted in a communications network where the capacity is under-utilized due to the low-density nature of the service area. If API were able to provide enhancements to

[5] Communication with meters must meet contractual service level agreements requiring that at least 98% of all interval data is acquired each day. While it is acknowledged that SCADA device communication differs from AMI data, both in content and priority, the option presented by AMI is considered viable and worth further exploration.

customer service beyond those associated with the basic functionality of the AMI system, the strategy would be perceived as beneficial for many reasons.

Political Factors

- **Leverage the AMI:** the regulators (i.e. OEB and Ministry of Energy) advocate for leveraging the AMI network.

Economic Factors

- **Communication:** taking advantage of the AMI network will minimize communication costs.

Social Factors

- **AMI Interface:** API understands the AMI network; implementing additional functionality will minimize training, and the adoption of new user interfaces.

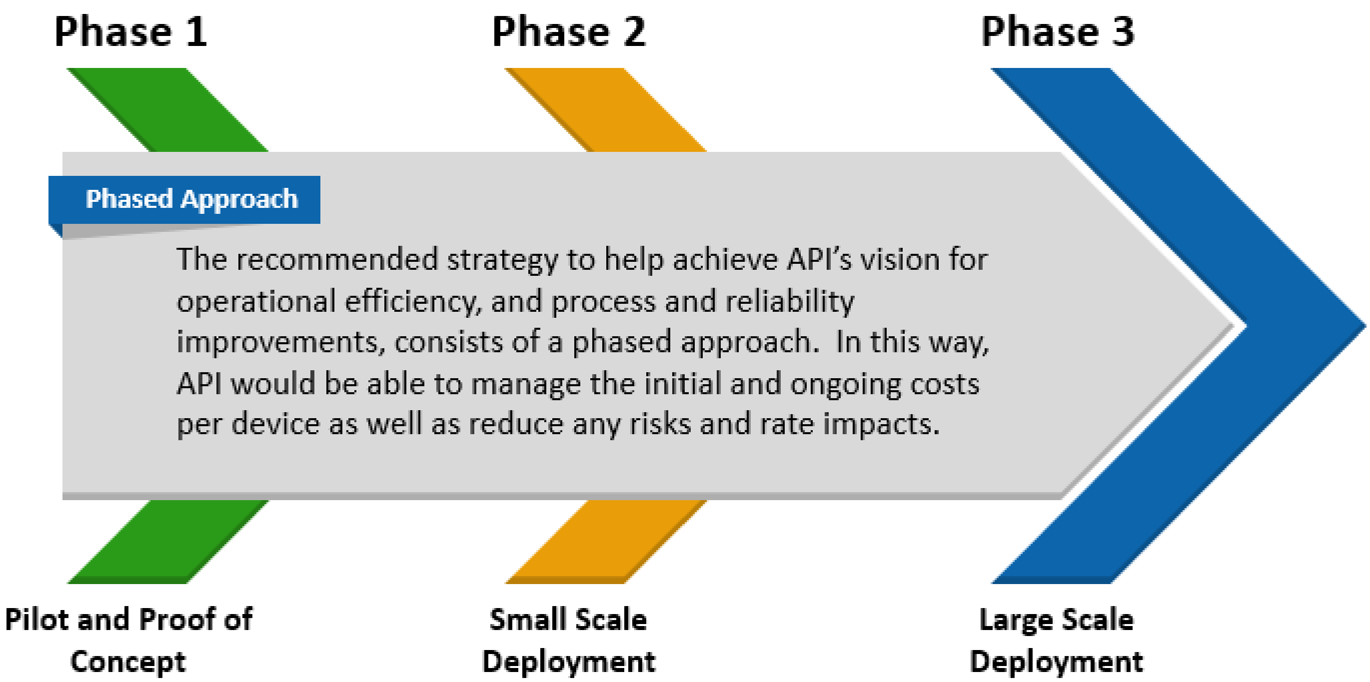
Technological Factors

- **Infrastructure:** modifications to existing infrastructure will be required, but costs will be deferred until the concept is proven successful.

Section 6.0 Recommended Strategy

6.1 Leverage Existing Communication Technology

This strategy recommended and evaluated within this business case is to work with the AMI provider, Sensus, to demonstrate the feasibility of utilizing AMI communication infrastructure as the communication medium for a Distribution Automation (DA) solution for API. It is expected that the AMI infrastructure can provide SCADA backhaul communications in areas that are beyond the reach of many traditional communication options. The possibility of using this solution is made possible by API's low customer density, which results in under-utilization of existing AMI towers – there is sufficient bandwidth to support both the AMI metering requirements for TOU billing as well as for DA.



6.2 Deploy a Phased Approach

6.2.1 Phase 1 – Pilot and Proof of Concept

A low-cost pilot project with Sensus would demonstrate the feasibility of this approach.

1. API installs a small number of RTM-II devices on existing recloser controls.
2. The pilot RTM-II devices would initially tuned to the existing smart meter frequency so that they can be used with the existing AMI infrastructure with little additional cost. If possible, communication parameters are also adjusted

to increase the intervals between transmitted messages during the test phase.

3. Sensus connects the pilot devices to a test/demo system to avoid the setup of a dedicated API system and the associated $15k software implementation fee. For security purposes during this phase, API has the ability activate a function in each control box that would block operations received from remote supervisory systems. This would prevent anyone with access to the test system from accidently operating the device.
4. API and Sensus monitor the impact of these devices on meter read success in each area. The impact should be minimal given that API's TGB's are currently very much under-utilized.
5. If the devices perform well from a telemetry standpoint, API and Sensus arrange a time to test-operate the reclosers remotely (For each of the test reclosers, API has the ability to bypass the recloser and/or reconfigure the system so that the recloser can be operated multiple times without customer impact.)
6. Once all of the above goes well, API will experiment with adjusting transmit rates, to gauge the impact on meter read performance.

6.2.2 Phase 2 – Small-Scale Rollout

1. Assuming that the testing of pilot devices was successful, API pays the $15k software implementation fee for API-specific software setup. The pilot devices are transitioned to this system.
2. Licensing fees for the DA system start after an agreed-upon length of time that allows API to reasonably purchase, configure and install additional DA devices that are part of the Year One implementation strategy.
3. Additional devices continue to be added, still tuned to the existing meter communication frequency in order to avoid significant TGB upgrade and IC licensing costs at the early stages of implementation. If possible, transmit rates are adjusted to a level that balances desired performance for SCADA/OMS purposes with impact on AMI performance, depending on the number of devices in an area.

6.2.3 Phase 3 – Large-Scale Implementation

At the point where the number of and/or communication parameters of the devices installed within the area of coverage for any given TGB causes unacceptable issues with electric meter performance, then the following occurs:

1. API pays for Sensus to perform upgrades on TGB(s) in that area.
2. API re-tunes all of the DA devices in the area to the new frequency.
3. API begins paying the additional spectrum lease costs for the affected TGB(s)

It is expected that by the time that DA devices have a material impact on meter read performance (if it happens at all), there are a sufficient number of devices installed in each area that the TGB upgrade costs and ongoing incremental costs are relatively small when considered on a cost/device basis.

6.3 Implement SCADA-Capable Equipment

In February 2014, API released an RFI (#2014-O51) to gather information regarding the functionality and cost of available products and services in order to develop a long-term plan for SCADA implementation and reliability improvement in API's service area. API gathered specific information on three product groups:

1. **SCADA-Capable Fault Circuit Indicators (FCI):** devices that provide visual or remote indication of a fault on the

electric power system.

2. **SCADA-Capable Reclosers:** devices that sense and interrupt fault currents and automatically restore service after momentary outages.

3. **SCADA-Capable Switches:** electrical disconnect (load break) switches for overhead distribution and substations.

Because SCADA systems are scalable, API can start small and expand SCADA throughout the service territory over a number of years. It is recommended that API gradually implement SCADA equipment, on a location by location basis, starting with the most problematic areas.

The following projects should be priorities:

- Installation of additional SCADA-capable devices, especially on systems with loop configurations (e.g., portions of the East of Sault 34.5 kV)
- Replacement of main-line fused disconnects with reclosers (prioritize heavily loaded devices).
- Installation of additional fault circuit indicators (FCIs)

It is suggested that API not implement many SCADA-capable switches: the pricing approaches that of the 3-phase reclosers, but with less functionality and increased maintenance requirements.

6.4 Strategy Considerations

6.4.1 Implementation Considerations

In implementing a SCADA system, API will need to take the following into consideration:

- As a pre-requisite, a reliable, effective communications network is required for the service territory.
- To realise the full potential, API will need to integrate the SCADA system with other corporate systems, such as the Customer Information System (CIS), the Geographic Information System (GIS) and the Outage Management System (OMS).
- Training on the new system and devices will be required for Engineering and Operations staff.
- Business process changes will be required to leverage the opportunities and achieve benefits.
- Decisions on the use of the SCADA system should not be limited to a single department. The strategic and tactical needs of other users, such as customer service staff and senior management, should be considered in any decisions.
- Analysis is required to determine the appropriate location for each device. This analysis needs to consider circuit configuration and reliability history.
- Utilities need to consider best practice security measures in any type of technology implementation, such as encryption and firewall installations.
- API should define benchmarks and start to collect metrics *before* the SCADA implementation in order to demonstrate success of the project with improved metrics. In addition to the mandated service reliability KPIs, possible metrics include the items in the graphic below.

Switching/Work Protection and Hold-Offs

- Track costs required for switching/work protection related to Great Lakes Power Transmission (GLPT) requests for isolation
- Track costs in applying hold-offs for API work or in proximity to live circuits (e.g., forestry work)
- With SCADA, API should be able to sectionalize work areas remotely, reducing the costs for switching and hold-offs.

Engineering Work

- Track engineering field costs for fault analysis, setting changes, etc.
- Costs should be reduced with accurate data provided and analyzed to promote engineering decisions

Device Maintenance

- Track maintenance costs for devices
- It should be possible to compare maintenance of legacy device, which are typically managed on a schedule, to maintainance of new devices, based on real-time data

Call Centre

- Calculate current after-hours call centre costs
- The call centre will be eliminated once API moves to 24/7 coverage with central control with CNPI

Power Quality

- Track variations in power quality
- A trend in improved power quality will demonstrate value in SCADA project

Customer Communication

- Track the time taken to communicate information to customers, such as outage cause, status, progress etc.
- With real-time data, API should be able to significantly reduce the time to communicate outage-related information to customers

Travel/Patrol Time

- Time taken for restoration crew travel and patrol during outages
- SCADA automation will enable dispatch to the exact location of an outage, reducing travel and patrol time

Avoided Interruptions

- Track the number and duration of any other avoided interuptions that are not already captured through KPI reliability measures

6.4.2 Staffing Considerations

In terms of staffing, The City of Medicine Hat employs only a half resource to run their SCADA network, including both maintenance and data analysis. PowerStream, a much larger utility, allocates 1.5 full-time resources to support SCADA outage monitoring and assessment requirements. However, API plans that initial control of the SCADA master station will be managed by an existing control room at CNPI. This will result in savings by eliminating the need for API SCADA management resources.

6.4.3 Expected Risks

The risks associated with API's SCADA project are outlined below. It is important to note that the biggest risk factor for API is not the devices themselves—they are proven to provide benefits--but the communications strategy, which must provide comprehensive and reliable coverage in order to achieve the benefits.

Risks and Risk Mitigation Strategy	
Risk	**Mitigation Strategy**
Reliable communications: To achieve the identified benefits, the SCADA system requires comprehensive coverage and reliable communications service.	Complete the staged pilot and ensure comprehensive and reliable communications coverage before proceeding.
Latency of communications: with the Sensus communications solution, the latency of data is expected to be about 9 seconds. For basic switching and monitoring, 9 seconds should not be an issue. A potential future challenge is related to the more advanced "Smart Grid" concepts that rely on the SCADA head-end to make intelligent switching decisions based on real-time status.	If there is varying latency from the devices involved, it may require some adjustment to the routines and/or adding some delay to make sure that status changes from all devices involved are considered before the next automatic operation is initiated.
Schedule Creep: There is a risk that due to potential competing projects over the next few years, devices could be deployed more slowly than captured in the financial analysis, resulting in a longer payback period. The business case justification rests on reaping benefits from these device deployments.	API requires a commitment to deploy the devices according to the defined schedule.
Incorrect financial assumptions: Assumptions made in the business case financial analysis, such as the annual rate of equipment failures, if incorrect, could positively or negatively affect the business case.	All assumptions made during the financial analysis for this business case are conservative. For example, troubleshooting requirements are estimated as higher than typical for most utilities due to the size of API's service territory.

Risks and Risk Mitigation Strategy	
Risk	**Mitigation Strategy**
Security: SCADA systems can be vulnerable to cyber infrastructure security risks, for example, a hacker controlling devices by sending commands over the network. Any malicious penetration of the system could result in consequences that extend well beyond the utility by affecting businesses and the general public.	API must be vigilant in implementing best practice security measures, including the following: • SCADA-controlled security switches • Virtual Private Network (VPN) and firewall installations • Intrusion alarming • Password protection
Quantifying Reliability Benefits: SCADA reliability benefits can be affected by other factors, such as weather and restoration crew availability, which can skew outage durations. Variations in these factors can appear to either reduce or enhance benefits.	API should employ multiple measures to quantify SCADA system benefits. Reliability KPIs should not be the only metrics. (See *Section 6.4.1: Implementation Considerations* for proposed metrics.)
Maintenance of Devices: API's service territory is a harsh environment for SCADA-capable devices.	For long life reliability, devices should have a modular design that enables easier troubleshooting, testing, and replacement of parts.
Legacy Support: Due to the long-term nature of the SCADA project, there is a risk that the vendor ceases to support legacy technology.	API should select vendors that have a history of supporting devices for a reasonable duration.
Equipment Obsolescence: As with any technology upgrade, there is a risk that the devices become obsolete before the full benefit of the project is realized.	API should understand the vendor(s)' product life cycle for devices to assess the risk of equipment obsolescence. Preventative maintenance can contribute to extending the life of devices.

Section: 7.0 Financial Analysis

The complete financial analysis (Microsoft Excel workbook) is available with this report (see Appendix C).

7.1 Assumptions Made During the Analysis

Within the analysis, the following assumptions were made:

Interest Rate	The interest rate for the short term cost of funds is 3.5%.
Amoritization - AMI	The AMI is amoritized over a period of 15 years.
Amoritization – TGB, Software	The TGB and software is amoritized over a period of 5 years.
Maintenance	1% of devices are expected to failure annually and 1% of devices wil require troubleshooting.
Taxes	Provincial and Federal Sales Tax (HST) is not included in the calculations.
Contingency	A contingency of 2 % is included.
Inflation	A 2.5% per year increase in costs is included in the calculations.
NPV Discount	A 2% discount was used in the NPV calculation.

7.2 SCADA Strategy Summary

The business case is based on 15 years, which is the typical useful life span for SCADA devices. The resulting analysis shows an internal rate of return of 21.03% (18.66% based on NPV), with a payback period of just over 8 years.

SCADA Network		
Item	**Costs**	**Savings**
Communication Capital & Maintenance	$738,874.11	
SCADA Devices Capital & Maintenance	$1,872,734.13	
SCADA System Capital & Maintenance	$2,071,007.06	
Other Capital & Maintenance		
Cost Of Funds (COF)	$336,282.43	
Operational Savings		$7,937,256.81
Totals	**$5,018,897.73**	**$7,937,256.81**
Benefits to Cost Ratio	1.581	
Payback Period	8.08	Years
Internal Rate of Return (IRR)	21.03%	
Total Capital (No COF)	**$1,941,793.69**	
Total Operating	$3,077,104.04	

SCADA Network (NPV Values)		
Item	**Costs**	**Savings**
Communication Capital & Maintenance	$658,276.23	
SCADA Devices Capital & Maintenance	$1,712,679.85	
SCADA System Capital & Maintenance	$1,797,666.47	
Other Capital & Maintenance		
Cost Of Funds (COF)	$288,434.76	
Operational Savings		$6,736,468.67
Totals	**$4,457,057.31**	**$6,736,468.67**
Benefits to Cost Ratio	1.511	
Payback Period	8.31	Years
Internal Rate of Return (IRR)	18.66%	
Total Capital - NPV (No COF)	**$1,796,875.58**	
Total Operating	$2,660,181.73	

SCADA System Asset Strategy Summary	TOTAL	Total NPV
Communication Capital Investments		
Comms Modules	$89,961.94	$84,082.33
Installation Costs - Regular Labour	$0.00	$0.00
AMI Network Infrastructure (TGB's)	$161,024.47	$152,969.17
AMI Head End System Infrastructure (RNI)	$9,254.28	$8,807.72
Cost of Funds on Capital	$0.00	$0.00
SCADA Devices Capital Investments		
Hardware	$874,226.31	$805,253.34
Software	$0.00	$0.00
Integration (Configuration & Training)	$807,326.68	$745,763.02
SCADA System Capital Investments		
Hardware	$0.00	$0.00
Software	$0.00	$0.00
Integration (Configuration & Training)	$0.00	$0.00
Total Capital Costs	**$1,941,793.69**	**$1,796,875.58**
Average Capital Cost Per Device	**$22,579.00**	**$20,893.90**
Average Cost Per Device Per Month (Based on 12 Year)	**$156.80**	**$145.10**
Communication O&M		
Maintenance	$471,438.42	$406,295.67
Labour to Run System	$7,194.99	$6,121.35
SCADA Devices O&M		
Maintenance	$191,181.13	$161,663.48
Labour to Run System	$0.00	$0.00
SCADA System O&M		
Hardware Maintenance	$0.00	$0.00
Software Maintenance	$2,071,007.06	$1,797,666.47
Labour to Run System	$0.00	$0.00
Finance / Corporate Services & Other O&M		
Cost of Funds on Capital (Total = sum over 12Yrs on a 15Yr Loan)	$336,282.43	$288,434.76
Total O&M Costs	**$3,077,104.04**	**$2,660,181.73**
Average O&M Cost Per Device Per Month	**$248.474**	**$214.808**
Total Costs Per Device Per Month (Based on 12 Yrs)	**$405.273**	**$359.904**
Totals	**$5,018,897.73**	**$4,457,057.31**

Annual rate to recover costs	**$4,863.27**	**$4,318.85**

The following table outlines the year-by-year breakdown for the totals in the above table.

Scada System Asset Strategy Summary	Year By Year Break Down											
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Communication Capital Investments												
Comms Modules	$14,644.97	$16,737.11	$16,737.11	$12,552.83	$14,644.97	$14,644.97	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Installation Costs - Regular Labour	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
AMI Network Infrasctrucutre (TGB's)	$6,940.71	$51,361.25	$102,722.51	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
AMI Head End System Infrastructure (RNI)	$0.00	$4,627.14	$4,627.14	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cost of Funds on Capital	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Scada Devices Capital Investments												
Hardware	$67,140.42	$89,984.80	$108,023.20	$183,026.67	$210,395.66	$215,655.55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Software	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Integration (Configuration & Training)	$77,700.00	$95,786.25	$104,799.84	$160,564.39	$181,963.56	$186,512.64	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Scada System Capital Investments												
Hardware	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Software	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Integration (Configuration & Training)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Capital Costs	$166,426.10	$258,496.55	$336,909.80	$356,143.89	$407,004.19	$416,813.17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Average Capital Cost Per Device												
Average Cost Per Device Per Month (Based on 12 Year)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Commnication O&M												
Maintenance	$0.00	$8,328.85	$41,226.20	$42,375.43	$43,557.38	$44,688.06	$45,892.64	$47,130.61	$48,082.81	$49,054.30	$50,045.46	$51,056.70
Labour to Run System	$0.00	$117.60	$258.30	$405.96	$524.66	$667.59	$817.33	$837.76	$858.71	$880.17	$902.18	$924.73
Scada Devices O&M												
Maintenance	$0.00	$0.00	$4,265.25	$9,024.37	$14,476.44	$17,278.30	$20,513.40	$23,899.45	$24,496.94	$25,109.36	$25,737.10	$26,380.52
Labour to Run System	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Scada System O&M												
Hardware Maintenance	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Software Maintenance	$0.00	$165,900.00	$170,047.50	$174,298.69	$178,656.15	$183,122.56	$187,700.62	$192,393.14	$197,202.97	$202,133.04	$207,186.37	$212,366.03
Labour to Run System	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Finance / Corporate Services & Other O&M												
Cost of Funds on Capital (Total = sum over 12Yrs on a 15Yr Loan)	$3,181.94	$8,124.20	$14,565.66	$21,374.86	$29,156.47	$37,125.62	$37,125.62	$37,125.62	$37,125.62	$37,125.62	$37,125.62	$37,125.62
Total O&M Costs	$3,181.94	$182,470.65	$230,362.90	$247,479.31	$266,371.09	$282,882.12	$292,049.61	$301,386.58	$307,767.04	$314,302.49	$320,996.72	$327,853.60

7.3 Costs for Devices

Device costs are based on the average price for each device as provided by vendors in response to API's RFI for SCADA-capable equipment.

SCADA Device Costs			
Category	**Cost/Mtr**	**Quantity**	**Cost**
3-Phase Reclosers	$29,294.65	18	$527,303.77
1-Phase Reclosers	$9,833.16	22	$216,329.47
Integrate Existing Dev	$0.00	26	$0.00
Fault Indicators	$1,338.49	20	$26,769.75
	Total:	86	$770,402.99

SCADA Device Costs By Year								
Billing UOM	2014	2015	2016	2017	2018	2019	2020	Checksum
3-Phase Reclosers	$58,589.31	$60,054.04	$61,555.39	$126,188.55	$129,343.27	$132,576.85	$0.00	$568,307.41
1-Phase Reclosers	$0.00	$20,157.97	$41,323.84	$42,356.94	$65,123.80	$66,751.89	$0.00	$235,714.44
Integrate Existing Dev	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fault Indicators	$5,353.95	$5,487.80	$0.00	$5,765.62	$5,909.76	$6,057.50	$0.00	$28,574.63
Total:	$63,943.26	$85,699.81	$102,879.24	$174,311.11	$200,376.82	$205,386.24	$0.00	$832,596.48

7.4 Costs for Device Installation

The following are installation costs by device type, including installation costs by year over the deployment period.

Installation Costs			
Category	Cost/Mtr	Quantity	Cost
3-Phase Reclosers	$25,000.00	18	$450,000.00
1-Phase Reclosers	$7,500.00	22	$165,000.00
Integrate Existing Dev	$1,500.00	26	$39,000.00
Fault Indicators	$3,000.00	20	$60,000.00
	Total:	86	$714,000.00

Installation Costs By Year								
Billing UOM	2014	2015	2016	2017	2018	2019	2020	Checksum
3-Phase Reclosers	$50,000.00	$51,250.00	$52,531.25	$107,689.06	$110,381.29	$113,140.82	$0.00	$484,992.42
1-Phase Reclosers	$0.00	$15,375.00	$31,518.75	$32,306.72	$49,671.58	$50,913.37	$0.00	$179,785.42
Integrate Existing Dev	$12,000.00	$12,300.00	$15,759.38	$0.00	$0.00	$0.00	$0.00	$40,059.38
Fault Indicators	$12,000.00	$12,300.00	$0.00	$12,922.69	$13,245.75	$13,576.90	$0.00	$64,045.34
Total:	$74,000.00	$91,225.00	$99,809.38	$152,918.47	$173,298.62	$177,631.09	$0.00	$768,882.56

7.5 Deployment Schedule

The deployment schedule shows the number and type of devices to be deployed each year over the next five years, following the three-phase approach. The first phase, the proof of concept occurs in 2014. The second phase takes place in 2015, with the full roll-out commencing in 2016. It is critical that API adheres to this schedule in order to achieve the expected benefits.

Deployment Schedule								
Category	2014	2015	2016	2017	2018	2019	2020	Checksum
3-Phase Reclosers	2	2	2	4	4	4	0	18
1-Phase Reclosers	0	2	4	4	6	6	0	22
Integrate Existing Dev	8	8	10	0	0	0	0	26
Fault Indicators	4	4	0	4	4	4	0	20
Total:	14	16	16	12	14	14	0	86

7.6 Benefits

The following table outlines the benefits that API is expected to achieve for each year. The benefits include the following:

- **Interruption costs**: reductions in outage interruptions through reliability improvements. The figures were derived using the U.S. Department of Energy ICE Calculator and API outage analysis statistics
- **Avoided O&M costs:**
  - **Switching/work protection**: reduction in costs for switching/work protection related to GLPT (transmitter) requests for isolation
  - **Call centre**: reduction in after-hours call centre costs
  - **Hold-offs**: reduction in costs for applying hold-offs for API work on or in proximity to circuits
  - **Engineering field costs**: reduction in engineering field costs for fault analysis, setting changes etc.
  - **Maintenance**: reduction in 6-year maintenance costs due to legacy reclosers/switches being replaced by new units requiring maintenance

Interruption Costs	Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Rate	$666,018.00	$679,338.36	$692,925.13	$706,783.63	$720,919.30	$735,337.69	$750,044.44	$765,045.33	$780,346.24	$795,953.16	$811,872.23	$828,109.67
	Volume	-	0.163	0.349	0.535	0.674	0.837	1.000	1.000	1.000	1.000	1.000	1.000
	Total	$0.00	$110,589.97	$241,718.07	$378,047.06	$486,201.39	$615,631.55	$750,044.44	$765,045.33	$780,346.24	$795,953.16	$811,872.23	$828,109.67
	NPV	**$5,588,112.72**	No NPV	$6,563,559.10									
Avoided O&M Costs	Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Rate	$178,606.00	$182,178.12	$185,821.68	$189,538.12	$193,328.88	$197,195.46	$201,139.37	$205,162.15	$209,265.40	$213,450.70	$217,719.72	$222,074.11
	Volume	-	-	-	0.163	0.349	0.535	0.674	0.837	1.000	1.000	1.000	1.000
	Total	$0.00	$0.00	$0.00	$30,855.04	$67,440.31	$105,476.64	$135,652.13	$171,763.66	$209,265.40	$213,450.70	$217,719.72	$222,074.11
	NPV	**$1,148,355.95**	No NPV	$1,373,697.71									
Avoided Capital Costs	Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Benefit	$0.000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Volume												
	Total	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	NPV	**$0.00**	No NPV	$0.00									

7.7 Capital and Operating Costs

The following table shows the total capital and operating costs for each year (alternatively, view this large table in the Excel Workbook).

SCADA Devices 86

Communications	Cost Allocation		Phase 1 POC 2014		Phase 2 Small 2015		Phase 3 Large 2016		2017		2018		2019	
	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating
AMI Network Infrastructure														
RTM-II (Remote Telemetry Module)	1.1.1	2.1.1	$13,947.59		$15,940.10		$15,940.10		$11,955.08		$13,947.59		$13,947.59	
Collectors (TGB's)	1.1.3	2.1.1	$6,610.20		$48,915.48		$97,830.96	$23,135.70		$23,598.41		$24,070.38		$24,551.79
Headend System (RNI Fees)	1.1.4	2.1.1			$4,406.80	$7,932.24	$4,406.80	$15,864.48		$16,181.77		$16,505.40		$16,835.51
Cost of Funds	1.1.5	2.1.3		$393.05		$1,717.29		$3,976.76		$4,205.34		$4,472.00		$4,738.67
Comms Warranty Costs (1% Annual Failure Rate)	1.1.1	2.1.1						$262.87		$577.37		$907.43		$1,172.75
Comms Trouble Shooting Modules 1% Per Yr	1.1.2	2.1.2				$112.00		$246.00		$386.63		$499.68		$635.80
Contingency at 2.0%			$1,027.89	$19.65	$3,463.12	$488.08	$5,908.89	$2,174.29	$597.75	$2,247.48	$697.38	$2,322.74	$697.38	$2,396.73
Section Sub Total			$21,585.68	$412.70	$72,725.50	$10,249.61	$124,086.75	$45,660.10	$12,552.83	$47,196.99	$14,644.97	$48,777.64	$14,644.97	$50,331.25
SCADA Devices														
SCADA Devices														
3-Phase Reclosers	1.2.1	2.2.1	$58,589.31		$60,054.04		$61,555.39		$126,188.55		$129,343.27		$132,576.85	
Installation	1.2.3	2.2.1	$50,000.00		$51,250.00		$52,531.25		$107,689.06		$110,381.29		$113,140.82	
Warranty Costs	1.2.1	2.2.1						$755.65		$1,549.08		$2,381.71		$4,068.75
1-Phase Reclosers	1.2.1	2.2.1	$0.00		$20,157.97		$41,323.84		$42,356.94		$65,123.80		$66,751.89	
Installation	1.2.3	2.2.1	$0.00		$15,375.00		$31,518.75		$32,306.72		$49,671.58		$50,913.37	
Warranty Costs	1.2.1	2.2.1						$0.00		$267.25		$821.79		$1,403.90
Integrate Existing Dev	1.2.1	2.2.1	$0.00		$0.00		$0.00		$0.00		$0.00		$0.00	
Installation	1.2.3	2.2.1	$12,000.00		$12,300.00		$15,759.38		$0.00		$0.00		$0.00	
Warranty Costs	1.2.1	2.2.1						$3,181.41		$6,521.88		$10,320.74		$10,578.76
Fault Indicators	1.2.1	2.2.1	$5,353.95		$5,487.80		$0.00		$5,765.62		$5,909.76		$6,057.50	
Installation	1.2.3	2.2.1	$12,000.00		$12,300.00		$0.00		$12,922.69		$13,245.75		$13,576.90	
Warranty Costs	1.2.1	2.2.1						$125.09		$256.43		$262.84		$404.11
Cost of Funds	1.1.5	2.1.3		$2,637.37		$6,020.04		$9,895.29		$16,151.67		$23,296.06		$30,619.06
Contingency at 2.0%			$6,897.16	$131.87	$8,846.24	$301.00	$10,134.43	$697.87	$16,361.48	$1,237.32	$18,683.77	$1,854.16	$19,150.87	$2,353.73
Section Sub Total			$144,840.42	$2,769.24	$185,771.05	$6,321.04	$212,823.04	$14,655.30	$343,591.06	$25,983.63	$392,359.22	$38,937.30	$402,168.20	$49,428.31
SCADA System														
SCADA System														
SCADA License	1.3.3	2.3.2				$158,000.00		$161,950.00		$165,998.75		$170,148.72		$174,402.44
SCADA Implementation	1.3.3	2.3.2												
SCADA Integration	1.3.3	2.3.2												
SCADA Staffing	1.3.3	2.3.2												
Other	1.3.3	2.3.2												
Contingency at 2.0%			$0.00	$0.00	$0.00	$7,900.00	$0.00	$8,097.50	$0.00	$8,299.94	$0.00	$8,507.44	$0.00	$8,720.12
Section Sub Total			$0.00	$0.00	$0.00	$165,900.00	$0.00	$170,047.50	$0.00	$174,298.69	$0.00	$178,656.15	$0.00	$183,122.56
			2014		2015		2016		2017		2018		2019	
			Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating
Totals			$166,426.10	$3,181.94	$258,496.55	$182,470.65	$336,909.80	$230,362.90	$356,143.89	$247,479.31	$407,004.19	$266,371.09	$416,813.17	$282,882.12

Communications	2020		2021		2022		2023		2024		2025	
	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating
AMI Network Infrastructure												
RTM-II (Remote Telemetry Module)	$0.00											
Collectors (TGB's)		$25,042.83		$25,543.68		$26,054.56		$26,575.65		$27,107.16		$27,649.30
Headend System (RNI Fees)		$17,172.22		$17,515.67		$17,865.98		$18,223.30		$18,587.77		$18,959.52
Cost of Funds		$4,738.67		$4,738.67		$4,738.67		$4,738.67		$4,738.67		$4,738.67
Comms Warranty Costs (1% Annual Failure Rate)		$1,492.23		$1,826.94		$1,872.61		$1,919.43		$1,967.42		$2,016.60
Comms Trouble Shooting Modules 1% Per Yr		$778.41		$797.87		$817.82		$838.26		$859.22		$880.70
Contingency at 2.0%	$0.00	$2,461.22	$0.00	$2,521.14	$0.00	$2,567.48	$0.00	$2,614.77	$0.00	$2,663.01	$0.00	$2,712.24
Section Sub Total	$0.00	$51,685.57	$0.00	$52,943.97	$0.00	$53,917.12	$0.00	$54,910.08	$0.00	$55,923.24	$0.00	$56,957.04
SCADA Devices												
SCADA Devices												
3-Phase Reclosers	$0.00											
Installation	$0.00											
Warranty Costs		$5,838.66		$7,694.52		$7,886.88		$8,084.06		$8,286.16		$8,493.31
1-Phase Reclosers	$0.00											
Installation	$0.00											
Warranty Costs		$2,302.39		$3,244.94		$3,326.06		$3,409.21		$3,494.44		$3,581.80
Integrate Existing Dev	$0.00											
Installation	$0.00											
Warranty Costs		$10,843.23		$11,114.31		$11,392.17		$11,676.97		$11,968.89		$12,268.12
Fault Indicators	$0.00											
Installation	$0.00											
Warranty Costs		$552.29		$707.62		$725.31		$743.44		$762.03		$781.08
Cost of Funds		$30,619.06		$30,619.06		$30,619.06		$30,619.06		$30,619.06		$30,619.06
Contingency at 2.0%	$0.00	$2,507.78	$0.00	$2,669.02	$0.00	$2,697.47	$0.00	$2,726.64	$0.00	$2,756.53	$0.00	$2,787.17
Section Sub Total	$0.00	$52,663.41	$0.00	$56,049.47	$0.00	$56,646.95	$0.00	$57,259.38	$0.00	$57,887.11	$0.00	$58,530.54
SCADA System												
SCADA System												
SCADA License		$178,762.50		$183,231.56		$187,812.35		$192,507.66		$197,320.35		$202,253.36
SCADA Implementation												
SCADA Integration												
SCADA Staffing												
Other												
Contingency at 2.0%	$0.00	$8,938.12	$0.00	$9,161.58	$0.00	$9,390.62	$0.00	$9,625.38	$0.00	$9,866.02	$0.00	$10,112.67
Section Sub Total	$0.00	$187,700.62	$0.00	$192,393.14	$0.00	$197,202.97	$0.00	$202,133.04	$0.00	$207,186.37	$0.00	$212,366.03
	2020		2021		2022		2023		2024		2025	
	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital	Operating
Totals	$0.00	$292,049.61	$0.00	$301,386.58	$0.00	$307,767.04	$0.00	$314,302.49	$0.00	$320,996.72	$0.00	$327,853.60

Section: 8.0 Conclusion

SCADA is at the core of smart grid decision-making. This report clearly demonstrates the advantages of a SCADA strategy for API. Not only will the utility and its customers benefit from the implementation, but the financial analysis indicates a positive return on investment over the longer term. By adopting a phased approach using Sensus, an existing technology, as the communications medium, the risks are low. The business case justification, however, rests on reaping benefits from device deployments; API needs to commit to deploying devices according to the planned schedule. By adhering to the proposed approach and leveraging both quantifiable and unquantifiable benefits, SCADA will position API for the changing demands of the future.

Appendix A: API Outage Analysis

Please refer to the file named *Outage Analysis and SCADA Benefits.xlsx*

Outage Analysis
and SCADA Benefits

Appendix B: Utility Interviews

City of Medicine Hat Utilities

Interview with Dean Stepanic, Project Manager, Automated Meters

About the SCADA System

What SCADA solution was deployed?

CMH selected Survalent. Dean was responsible for deploying the SCADA network and creating custom code.

In what year was the system deployed?

In the late 80s. Around 1995, CMH added analog and digital points to the website for managers and admin staff who are offsite.

What was the driver for SCADA?

The ability to control and manage outages remotely. Wanted to be able understand feeder info, view status and to control it remotely.

There was a safety concern in the early 90s with manually closing breakers. Arc flashing could occur, causing the person standing in front to be burned. CMH had a company come in and do an arc flash study. CMH wanted remote control for closing breakers.

Benefits

What benefits have you achieved (both quantifiable and non-quantifiable)?

Provide safety, visibility, faster response time on an outage. Can go into lockout: nobody can reclose a breaker until there is a site visit. Lines cleared, workers removed. The main benefit is that no one is in front of a device to operate it.

For each device type, what benefits have you achieved? What reliability improvements have you experienced?

FCIs: CMH puts FCIs on lines in different areas: if one detects fault and another one doesn't, it pinpoints where the fault is. This optimizes the crews' time to get to fault. Saves operational costs, customer outage time. With the old manual line fault indicators, the trouble truck would drive to them and then look up for visual indication. These indicators could be up to 10 km apart. Now CMH gets the info immediately in the SCADA system. CMH did not conduct a study to quantify savings and didn't spent much time on justifying financial benefits. It was an easy decision to make. Makes it easier for dispatching—CMH can identify the seriousness of a problem and the number of field staff required and make the right decision immediately.

Reclosers: CMH located reclosers in the same places as capacitor banks (there are 20 of these). If there is a fault in, for example, a rural area, and the first half of the feeder services a lot of customers, this keeps them isolated from faults in rural areas. In CMH's rural areas there are a lot of downed trees that affect the power lines. There are a few reclosers within the city that separate commercial from residential customers. In terms of quantifying savings, SAIDI, CAIDI numbers were automatically reduced—this was great for service levels. Reclosers save on breaker maintenance—there is a breaker counter, and a after certain number of counts, CMH has to maintain it. Remote access through SCADA provides information on the size of fault, data on the fault itself, such as single-phase or triple-phase, and the location of the fault. This information is valuable for troubleshooting. A three phase fault might be a customer transformer. With

SCADA, CMH has information “at their fingertips” to make decisions and send crews out.

Switches: CMH uses switches to isolate load. On a line that feeds customers, there is never just one place of connection. If feeder goes off because of fault, can isolate it with a MOD (motor operated device and then close the feeder and restore half the customers. If line fault indicator tells you where fault is, can isolate it with a switch. Can do it all from the control room. It won’t open if it detects load. CMH closes the switch when the fault is restored. Provides faster restoration to customers and performance statistics are greatly improved. There are also safety benefits to switches. In the 80s, CMH used to send crews out with a pole with a handle. In one instance the switch separated from the pole and broke, causing an arc over the crew member’s head. This was a huge safety concern. CMH then made the decision to motorize switches and not have people stand underneath them.

Costs

What were your SCADA implementation costs?

Don’t know.

What staffing levels have been required to support SCADA?

On the distribution side CMH requires less than ½ body to run SCADA network. CMH introduces software updates once a year. Some time is required for analysis and for understanding the data (included in the ½ body). In the past, CMH would send a truck out once a month to record information. The crew would spend a few days driving around and then put the information into a spreadsheet. Now this information is at their fingertips. There is time required to maintain the software, but the benefit is that CMH now has an asset management plan.

What skill set is required?

Power system background. Electrical engineer or assistant engineer.

What are your SCADA maintenance costs?

CMH pays $10,000 per year for “Gold” coverage. This means that service is only provided during business hours (no after hours).

Can walk into any substation and communicate with any device. More control centres mean greater maintenance costs.

What unforeseen costs have you encountered (lessons learned)?

CMH’s lessons learned relate to the communications solution. They deployed Motorola radio communication to connect to fibre. The technology wasn’t up to standards back then. Motorola has lasted its service life and is now being switched out.

CMH has fibre in each substation and power plant. Radio communication is used for reclosers, FCIs etc; however, some reclosers have fibre. Most are radio to the nearest fibre, with a radius of a kilometre or so. CMH reduces risk with repeaters.

Other Information Supplied During the Interview

- CMH gets their SCADA system audited every five or six years.
- CMH has a redundant environment for failover. This environment is also used for testing purposes.
- CMH has a voltage reduction programs with capacitor banks. Everything is automated. There is no manual interface other than monitoring through the SCADA system.

- CMH has four substations with an average of six feeders for each substation, plus the main breaker – two in each substation.
- Pad mounted switchgear – have RTUs controlling padmount switchgear – a couple dozen.
- CMH has approximately 20 motorized operated switches on poles
- Capacitor banks (pad mounted and pole mounted) are controlled by SCADA
- A dozen transformers have breakers
- Distribution lines are between 5 and 10 km long

PowerStream

Interview with John McClean, Vice-President, Operations

About the SCADA System

What SCADA solution was deployed?

PowerStream selected Survalent. Upon the formation of PowerStream from the original three founding utilities, there were three different SCADA systems being used. It was decided to invite two of the predecessor SCADA vendors to bid for a new system (Siemens and Survalent). Our staff already had some skills in maintaining the two systems so we didn't have to start re-training from scratch.

In what year was the system deployed?

Survalent went into production in December 2007.

What was the driver for SCADA?

PowerStream has multiple large transformer stations that it is required to monitor, control, and operate because they are transmission connected. There are also several hundred line devices that are remotely operated and many smaller municipal substation. We had to bring all assets under one single control system. Coincident with the move to PowerStream's new control centre, the new SCADA had to be ready in time for move-in by February 2008.

Benefits

What benefits have you achieved (both quantifiable and non-quantifiable)?

Benefits are a non-issue. Some kind of SCADA, DMS, EMS is required to operate our system. PowerStream is obligated to have 24/7 control over its direct-connect (transmission system) transformer stations as well as the customer reliability expectations of managing our power supply 24/7.

What reliability improvements have you experienced?

Barrie Hydro had a SAIDI of almost 3 hours when the merger occurred but they did not have 24/7 coverage in the control room. They did have SCADA but no after-hours control. When the Barrie system was migrated to the PowerStream SCADA system and coupled with 24/7 monitoring and control, the overall Barrie SAIDI improved to much less than one hour. Most of these CMI savings were the ability to respond to unplanned outages after-hours.

What outage costs have you been able to avoid?

All our predecessor utilities have had SCADA systems for 30+ years so cost avoidance is difficult to measure. When the Barrie merger occurred, less after hour call-outs to Line staff may have been made to visit substations to close circuit breakers as this is now done remotely from the 24/7 control room. SCADA is a business requirement and

For each of the device types, what benefits have you achieved?

Reclosers: Fewer CMIs; reducing impact of outage to just those customers downstream of recloser.

Switches: Flexibility in operating system, fewer CMIs, quicker response of power restoration to customers outside of fault zone.

Fault circuit indicators: Fewer CMIs; shorter patrol bounds, faster restoration.

Costs

What were your SCADA implementation costs?

In 2006, our SCADA system was approximately $400k, including hardware (redundant servers, approximately 15 client machines). We also engaged vendor to create the overall SLD and support database migration (from predecessor SCADAs) for around $100k. Internal staff costs were around $100k as well.

What staffing levels have been required to support SCADA?

We allocate around 1.5 FTEs to support the OM&A requirements of SCADA

What are your SCADA maintenance costs?

We have selected a Platinum service which provides unlimited 24/7 support – approximately $50k annually

What unforeseen costs have you encountered (lessons learned)?

There are continual challenges with M&A activities. Ensure that all SCADA related work is completed ASAP instead of letting it go stale or extraordinary effort is required afterwards

Fortis BC

Discussion with Paul Chernikhowsky, Director, Engineering Services

- Fortis BC uses Survalent for SCADA.
- Implemented SCADA in late 80s. The system has gone through three generations, starting with "Generation One," in which Fortis BC was able to control 15 to 20 of the 60 to 70 substations. The third generation introduced Window-based machines.
- SCADA is used for substation breaker control: reclosing breakers, analog measurements, control of substation devices.
- Remote automation contributed to much of the cost justification.
- Alarms was another justification. Chargers have failed in substations, but the utility did not know until substation inspection or trips. Part of safety justification – high temperature, low oil, etc.
- FortisBC more recently went through an application for a Distribution Substation Automation Program to roll out the program to the rest of the substations.
- The project was estimated to be $6.38 million (30 substations).
- The project was stated as providing improved substation data collection, remote equipment operation, improved distribution reliability and enhanced power system planning and safety.
- Fortis BC had to explain the benefits in straight-forward terms for the interveners.
- The original financial analysis showed the net present value to be 2.5 million.

- The utility brought in non-quantifiable benefits to bring the net present value to zero (considering that not all of these benefits may materialize fully).
- Fortis BC considered customer impact and satisfaction in their application. The utility considered lost opportunity costs for customers (lost business for commercial customers and annoyance factor for residential customers).
- The BC Utilities Commission deliberated and ultimately provided a positive decision (December 24, 2007).
- Fortis BC never considered lost sales in their justification.
- Fortis BC committed to periodically updating the Commission on cost savings.
- It is important to note that Fortis BC did not have an AMI network at the time (the utility is currently deploying Itron OpenWay).
- Fortis BC's "lesson learned" was to take a step back and reposition the benefits to the regulator.

Paul provided a package of documents the regulatory proceedingm available on the BC Utilities Commission (BCUC) website: http://www.bcuc.com/ApplicationView.aspx?ApplicationId=162

Appendix C: Financial Analysis

Due to the size of the financial analysis, this information is available as a separate spreadsheet. Please refer to the file named *SCADA Analysis_20140506.xlsx*

4.0-VECC-21

Reference E4/T3/S1/pg.5

a) Please provide the actual bad debt in 2009 through 2013 and 2014 to-date. Please provide the forecast bad debt in 2014 and 2015.
b) For the year 2014 please provide the spending on "customer services" to date.

RESPONSE:

a) The bad debt expense is shown below.

	2009	2010	2011	2012	2013	2014 actual to June 30	2014 Forecast	2015 Forecast
Bad debt expense	$ 42,067	$ 44,463	$ 53,491	$ 59,034	-$ 8,509	$ 65,667	$ 71,000	$100,000

b) The spending on Customer Services to June 30, 2014 is $459,054.

(page left blank intentionally)

4.0 - VECC - 22

Reference: E4/T4/S1/Appendix B

a) API's FTE count has increase by 8.71 FTE's from the last Board approved in 2011. Please provide a job description list of each new position added to API since 2011.
b) Please assign each new position to one of the categories below:
   - Required for smart meter/TOU;
   - Required for incremental regulatory or government requirements;
   - Customer growth driven;
   - Required for enhanced maintenance programs (vegetation management, SCADA etc.);
   - Backfill for expected retirement
   - Other – please describe

RESPONSE:

a) As noted in evidence (Exhibit 4, Tab 4, Schedule 1, Appendix B, page 1, line 10), the number of FTE's over the period 2011 Board Approved to 2015 Test Year has increased by 8.71 FTE's. As further set out on line 26, the increase of 5.82 from 2011 Actual to 2012 Actual is based on a change of methodology from employee FTEs (in the last rate application) to FTE's using the shared services BDR methodology. Accordingly, the 2011 Actual and 2012 Actual are not comparable figures. As noted in the last OEB approved rate application, the migration into FortisOntario would include the sharing of corporate services (see EB-2009-0278, Exhibit 4, Tab 5, Schedule 1, page 1, line 28). The additional 5.82 FTE's would therefore include the following: executive, finance, information technology, human resource, safety and environmental, regulatory and engineering design management. Each of the individual functions identified above were reviewed to determine the appropriate allocations ultimately resulting in the assignment of full time equivalents to each business unit. BDR was engaged by FortisOntario to review the cost allocation methodology and computations used for the allocation of shared services and to provide its opinions as to the reasonableness thereof. A copy of the BDR Report confirming BDR's opinion is attached as Exhibit 4, Tab 5, Schedule 1, Appendix B.

The remaining 2.9 FTE's and their job descriptions and justifications are provided in evidence in Exhibit 4, Tab 4, Schedule 1, Appendix B, page 2, line 10.

b) As noted above, the 5.82 FTEs from 2011 Actual to 2012 Actual can be assigned to the category of "Other-please describe" and the explanation is provided above. The net 2.9 FTEs can be assigned to the category of "Other-please describe" and the descriptions are provided in evidence in detail in Exhibit 4, Tab 4, Schedule 1, page 2, Appendix B, Lines 20-31.

4-VECC - 23

Reference: E4/

For each of the years 2011 through 2015 please provide:

a) EDA membership fees
b) All other corporate membership fees

RESPONSE:

a) EDA membership fee are shown below.

	2011	2012	2013	2014	2015
EDA Membership fee	$ 14,265	$ 5,120	$ 5,400	$ 15,504	$ 15,811

b) Other corporate membership fees are shown below.

	2011	2012	2013	2014	2015
USF(Utilities Standard Forum)	$ -	$ -	$ 8,750	$ 9,100	$ 10,000

(page left blank intentionally)

4-VECC-24

Reference: E4/

a) Please provide all training and conference costs for the 2011-2019 period broken down into the following categories
   i. Training – operations/maintenance
   ii. Training – other
   iii. Conferences

RESPONSE:

a) Training and conference costs are shown below.

		2011 Actual	2012 Actual	2013 Actual	2014 Bridge Year	2015 Test Year
i	Training - operations/maintenance	$ 73,920	$ 54,854	$ 60,092	$ 78,000	$ 50,050
ii	Training - health, safety & environment		$ 30,764	$ 31,472	$ 53,000	$ 55,000
	- other (2011 includes HS&E)	$ 22,622	14,086	4,443	20,500	19,000
	Total Training - HS&E and other	$ 22,622	$ 44,850	$ 35,915	$ 73,500	$ 74,000
iii	Conferences	$ 9,513	$ 8,833	$ 8,109	$ 14,000	$ 9,600
	Grand Total Training	$ 106,055	$ 108,537	$ 104,116	$ 165,500	$ 133,650

(page left blank intentionally)

4-VECC-25

Reference: E4/T5/S1/pg.4

a) Please provide a description and breakdown of the services provided by CNPI for to API of $1,418,934 in 2015. Please compare this to the service provided in 2011 for $134,000.
b) Please show the reduction in costs at API due to the incremental services provided by CNPI since 2011

RESPONSE:

a) The following table shows the description and breakdown of the services provided by CNPI to API compared to the 2011 Board Approved amount of $134,000.

Costs for Services Provided to API		
DESCRIPTION	**Dollars 2015**	**Board Approved Dollars 2011**
Services		
Finance Service	548,448	27,766
IT Service	509,299	13,326
HR Service	134,078	43,807
HS&E Service	168,699	17,462
Regulatory Service	58,410	31,323
Total Services	1,418,935	133,685

b) CNPI does not provide any incremental services to API. The services provided are all essential core business services. In 2011 API had internal departmental costs for finance, IT and HS&E of approximately $1.1 million. The HR and regulatory functions had previously been provided by external sources.

(page left blank intentionally)

4-VECC-26

Reference: E4/T6/S1

a) Does API/Fortis purchase insurance from the MEARIE Group?
b) If please provide the 2015 insurance costs for API and the name of its carrier(s).

RESPONSE:

a) No, API/Fortis does not purchase insurance from the MEARIE Group.

b) The 2015 insurance costs for API are as follows.

a.	Liability, comp, etc.	$46,500
b.	Vehicle	36,036
	Total	$82,536

There are various underwriters of the insurance policies and Aon Reed Stenhouse Inc. is the insurance broker. The coverage and associated costs are managed by Fortis Inc. through a large group rate plan for the Fortis companies.

(page left blank intentionally)

4-VECC-27

Reference: E4/T6/S1

a) Please provide the operating name of the Vegetation Management Company operating under 2210652 Ontario.
b) Please confirm that API/Fortis has no interests (including minority interests) in any of the following companies: 2210652 Ontario; 1687921-Ontario and 2181437 Ontario
c) Please describe the services provided the Glenn R. Taylor and 2181437 and listed as “contractor monitoring’.

RESPONSE:

a) The operating name is Wilderness Environmental Services.

b) API/Fortis confirms that it has no interest in these companies.

c) Monitoring, coordinating, evaluating and verifying work performed by contractors including overseeing health, safety and environmental obligations, work progress and quality of work.

(page left blank intentionally)

4-VECC-28

Reference E4/T12/S2/pg.1

a) Please explain why the actual tax paid for the years 2011 ($106,324) and 2012 (0) do not match the amounts shown as actual income tax at the above reference.
b) We are unable to locate API's 2013 tax return. Please provide or direct to where it can be found in the evidence.
c) Please provide the actual provincial and federal tax paid by API for the years 2009 through 2013.

RESPONSE:

a) The actual tax paid for the years 2011 and 2012 do not match the amounts shown as actual income tax in Exhibit 4, Tab 12, Schedule 2, due to the cumulative eligible capital deduction.

The OEB's Decision and Order (EB-2007-0744) dated October 30, 2008 relating to Great Lakes Power Limited's cost of service rate application denies the recovery of the balance of Regulatory Asset Account 1574 that recorded deferred mitigation amounts since 2002. In their decision the Board also awarded the benefit of the tax treatment to the shareholder as follows:

"*The Board reiterates its view that the benefits of a tax loss should be realized by the party –shareholders or ratepayers – that bore the expenses or losses that gave rise to the tax loss. Since the Board has denied recovery of the amount accrued for rate mitigation in account 1574, the resulting losses should not be attributed to ratepayers but rather to Great Lakes Power Limited, which sustained those losses and should retain the related tax benefits.*"

API has treated the rate mitigation account losses as cumulative eligible capital deduction for income tax purposes. The associated deduction has not been included in the calculation of income tax expense included in the revenue requirement.

b) See response to 4-Energy Probe-28.

c) The actual provincial and federal income tax paid by API is shown below.

	Year ending October 8, 2009	Year ending December 31, 2009	Total 2009	2010	2011	2012	2013
Federal Tax Paid	$ 32,717	$ 40,223	$ 72,940	$ 127,435	$ 62,105	$ -	$ 107,263
Provincial Tax Paid	81,897	65,770	147,667	142,512	44,219	-	57,678
Total Income Tax Paid	$ 114,614	$ 105,993	$ 220,607	$ 269,947	$106,324	$ -	$ 164,941

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

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.

RESPONSE:

a) See Appendix 2-OB Note 3 (Exhibit 5, Tab 1, Schedule 3). The difference between the long-term debt rate of 5.118% per the Trust Indenture and the long-term debt of 5.15% used in Appendix 2-OA are the debt issue costs of $498,968 which are being amortized over the life of the Notes or $16,632 per year. The inclusion of the debt issue costs increases the effective long-term debt rate. The calculation of the effective long-term debt rate of 5.15% is shown in Appendix 2-OB. The $16,632 is not included elsewhere in the revenue requirement.

(page left blank intentionally)

5-Energy Probe-31

Ref: Exhibit 5, Tab 1, Schedule 1

a) Please confirm that API has only one long term debt note in the amount of $52 million at a rate of 5.118% with a maturity date of December 16, 2041. If this cannot be confirmed, please provide a list of all such notes including the principal, interest rate and maturity date.

b) Is any of the long term debt callable on demand or redeemable by API? If yes, please provide details. For example, what parties have the ability to redeem or call all or part of the debt and what amount of notice is required to do so?

RESPONSE:

a. API confirms that it has only one long-term debt note in the amount of $52 million at a rate of 5.118% with a maturity date of December 16, 2041.

b. As outlined in Section 4.1(b) of the Trust Indenture (Exhibit 5, Tab 1, Schedule 1, Appendix A), the Series 11-1 Notes are redeemable by the Corporation at a price equal to the Applicable Redemption Price (as described on page 2 of the Trust Indenture). This term of the Trust Indenture is common to third party long-term debt allowing for the redemption of the debt in the event of an unusual circumstance but at a significant premium to the borrower. API has no intention to redeem the Notes and the Notes are not callable.

(page left blank intentionally)

5.0 – VECC -29

Reference: E5/T1

a) Please provide API's actual return on equity for each of 2010 through 2013.

RESPONSE:

a) Algoma Power's actual return of equity per the audited financial statement for the years 2010 to 2013 are as follows;

2013	6.1%
2012	10.3%
2011	9.8%
2010	4.3%

(page left blank intentionally)

5.0 – VECC -30

Reference: E5/T1

a) Who are the current registered note holders issued under the Trust Indenture?

RESPONSE:

a) The registered note holders under the Trust Indenture are:

- The Manufacturers Life Insurance Company;
- The Canada Life Assurance Company; and
- The Empire Life Insurance Company.

(page left blank intentionally)

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.

RESPONSE:

There are no corrections or adjustments required to the RRWF provided with the Application as a result of interrogatories from Board staff and intervenors.

(page left blank intentionally)

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.

RESPONSE:

a) The reconciliations of the numbers are shown below. The amounts referenced in the interrogatory are shown in bold.

Distribution revenue at current rates	20,640,736
Other operating revenue	436,758
Gross revenue deficiency	3,631,300
Total revenue at approved rates plus gross revenue deficiency	**24,708,794**
Distribution revenue at current rates	20,640,736
Other operating revenue	436,758
Total revenue at current rates	**21,077,494**
Total operating expenses	16,759,688
Grossed up income taxes	440,336
Deemed interest	2,946,627
Deemed return on equity	3,716,538
Other operating revenue	(436,758)
Base revenue requirement	**23,426,431**
Distribution revenue at current rates	20,640,736
Recovery of stranded meters	(192,509)
Variation between Actual Rates & RRRP and the use of Equivalent Rates	(17,480)
	20,430,747
Transformer allowance addback	(74,096)
Net revenue	**20,356,651**

The inclusion of the stranded meter cost allocated to the Residential – R1 class and the add back of the transfomer ownership credit are detailed in Exhibit 8 Rate Design. The variation between the build up of revenue from actual tariffs and RRRP funding with revenues calculated using the continuity of equivalent rates occurs as a result of repetitive rounding; there is no impact on the recovery of the test year revenue requirement as is evidenced in the reconciliation provided in in Exhibit 8 Rate Design.

b) N/A

<u>6-Energy Probe-32</u>

Ref: Exhibit 6, Tab 1, Schedule 2 &
RRWF

The figures in the 2015 Test Required Revenue in Table 6.1.2.1 do not match the figures in the RRWF in the Initial Application at Proposed Rates on the Revenue Deficiency/Sufficiency sheet. Please provide a corrected RRWF and/or Table 6.1.2.1 so that the two balance.

RESPONSE:

The figures in Table 6.1.2.1 show the 2015 Test Year Revenue in a different format from the RRWF. It does not calculate the revenue deficiencies. Instead it includes the distribution revenue and revenue deficiency in the total revenue. If the distribution revenue at current rates and the revenue deficiency are removed the figures are exactly the same as the RRWF as shown below.

Revenue Deficiency(Sufficiency)			
Description	2015 Test Required Revenue	RRWF	Difference
Revenue			
Revenue Deficiency	-	3,631,300	
Distribution revenue	-	(3,631,300)	
Other operating revenue	436,758	436,758	
Total Revenue	436,758	436,758	-
Costs and Expenses			
Operation & Maintainence	7,033,345	7,033,345	
Billing & Collecting	1,117,294	1,117,294	
Administrative & General	4,554,240	4,554,240	
Depreciation & Amortization	3,947,009	3,947,009	
Property Taxes	107,800	107,800	
Deemed Interest	2,946,627	2,946,627	
Total Costs and Expenses	19,706,314	19,706,314	-
Utility Income before Income Taxes	(19,269,557)	(19,269,557)	-
Income Taxes			
Corporate Income Taxes	(5,146,148)	(5,146,148)	
Total Income taxes	(5,146,148)	(5,146,148)	-
Utility Net Income	(19,709,893)	(19,709,893)	-
Income Tax Expense Calculation			
Accounting Income	(19,269,557)	(19,269,557)	-
Tax Adjustments to Accounting Income	(149,869)	(149,869)	-
Taxable Income	(19,419,425)	(19,419,425)	-
Income Tax Expense	(5,146,148)	(5,146,148)	-
Tax Rate	26.5%	26.5%	0.0%
Actual Return on Rate Base			
Rate Base	99,266,498	99,266,498	-
Interest Expense	2,946,627	2,946,627	-
Net Income	(19,709,893)	(19,709,893)	-
Total Actual Return on Rate base	(16,763,266)	(16,763,266)	-
Actual Return on Rate Base	-16.89%	-16.89%	0.00%
Required Return on rate Base			
Rate Base	99,266,498	99,266,498	-
Return Rates			
Return on Debt	4.95%	4.95%	
Return on Equity	9.36%	9.36%	0.00%
Deemed Interest Expense	2,946,627	2,946,627	-
Return on Equity	3,716,538	3,716,538	-
Total Return	6,663,164	6,663,164	-
Expected Return on Rate Base	6.71%	6.71%	0.00%
Revenue Deficiency after Tax	23,426,431	23,426,431	-
Revenue Deficiency before Tax	31,872,695	31,872,695	

6-Energy Probe-33

Ref: Exhibit 6, Tab 1, Schedule 4

Please confirm that in the absence of the accounting change, the deficiency in 2015 would have been about $5.2 million ($3,631,300 deficiency plus $1,525,053 accounting change impact). If this cannot be confirmed, please show the calculation of the deficiency in 2015 in the absence of the account change.

RESPONSE:

The deficiency in 2015 would have been $1,525,053 higher in the absence of the accounting policy change.

(page left blank intentionally)

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.

RESPONSE:

a) API's rationale for proposing ratios outside the Board's Policy Range for these two classes remains consistent with the evidence submitted in Exhibit 7, Tab 1, Schedule 2 of the Application. API gave consideration to many factors related to the results of the 2015 Cost Allocation Study prior to arriving at its proposal to maintain Status Quo[1] revenue to cost ratios. The most salient of

[1] Status Quo revenue to costs ratios are the ratios determined on Output Sheet O1 of the 2015 Cost Allocation Study included with this Application

the factors considered are listed below and were discussed individually in the Application. These factors include:

- Functionality of the Cost Allocation Model
- The Board's Policy Range for the Revenue to Cost Ratios
- Consumer Centric Regulation / Listening to Our Customers
- The Customer's Ability to Pay / Sustainability of the Customer Classification

As stated in the Application, API is not questioning the appropriateness or effectiveness of the Board's Cost Allocation Model; API is supportive of the cost allocation model. The purpose of the discussion was to explain API's interpretation of the model's functionality and outputs, the applicability of the outputs to API's unique circumstances and how these factors contribute to API's proposal to maintain the Status Quo revenue to cost ratios. In API's last cost of service, EB-2009-0278, the cost allocation study yielded a revenue to cost ratio of 149.94% and the final value accepted in the settlement Agreement was 115%. With no material change to API's distribution system, the 2015 Cost Allocation Study has yielded a revenue to cost ratio of 55.03%. API has questioned whether or not the Cost Allocation Model is responsive of API's unique circumstances of customer density and the system configuration described in Exhibit 2, Tab 1, Schedule 1 and described pictorially on page 2 of this reference.

Further, the Board is introducing consumer centric regulation and asking distributors to improve their communications with their customers. Rising energy costs, particularly in the Seasonal customer classification, have given rise to customers expressing concerns related to energy costs and actively seeking ways to reduce their energy costs. This includes converting to energy sources such as propane powered refrigeration, heating and lighting and in some extreme instances disconnecting from the grid completely. API's approach to its Cost Allocation Study and its proposed revenue to cost ratios is an attempt to both listen and respond to its customers' expressed concerns, regardless of whether or not the Cost Allocation Study has appropriately allocated costs to its customer classes. Further complicating the issue and fuelling the customer's expressed confusion over this matter is the fact that often neighbours, residing adjacent to each other and utilizing the same distribution system assets are in different customer classifications. With one customer being classified a Residential – R1 and the other a Seasonal customer. As a result, API has chosen to propose status quo revenue to cost ratios in this Application.

The customer's ability to pay and the sustainability of the Seasonal and Street Lighting Customer Classification is also a consideration. The Seasonal and Street Lighting Customer Classifications are not subject to RRRP funding. Over the past number of years, API has experienced a continued migration of customers from the Seasonal class to the Residential – R1 class. Customers are expressing their awareness of the price differential existing between these two customer classes. As evidenced by the nature of the interrogatories from the Algoma Power Coalition, Street Lighting costs are also a concern for customers.

For all of these reasons, API is proposing ratios outside the Board's Policy Range for these two classes.

b) API confirms that the reference in Exhibit 7, Tab 1, Schedule 3, pages 2 and 3 to a Policy Range of 80% – 115% is an oversight. The intent is to assume a Policy Range of 85% – 115% similar to that selected for the Residential – R1 classification.

(page left blank intentionally)

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.

RESPONSE:

a) See the explanations in parts b & c.

b) API is inferring that the configuration of its electricity distribution system may not fit with the intended density allocation of the model. As described in Exhibit 2, Tab 1, Schedule 1, in the pictorial on page 2, API's electricity distribution system is comprised of many smaller distribution systems widely dispersed over a large geographic area; it is not a singularly contained system like many of the LDCs in Ontario. This type of dispersed sub-distribution systems means that portions of the distribution system behave like a “sub-transmission”.

c) No, API has not investigated 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?

RESPONSE:

a) API is uncertain as to why the input density information in the previous cost allocation was omitted.

b) A cost allocation model leaving the density information blank accompanies these responses.

c) API determines its total length of line from a geographical based mapping system.

(page left blank intentionally)

7-Energy Probe-34

Ref: Exhibit 7, Tab 1, Schedule 2

Please explain why the metering capital weighting factor for the seasonal class is 0.89 instead of the same 1.0 used for residential-R1. What is driving the lower capital cost for seasonal customers?

RESPONSE:

API's Residential – R1 customer class is a mixture residential and small general service customers. In most Ontario LDCs these small general service customers would be classified as General Service less than 50 kW and not part of the residential class. The Seasonal customer class is comprised entirely of residential style services. Therefore, using as a reference, the capital meter cost of the Residential – R1 class which includes residential and small general service (which uses more expensive meters than residential class), as a 1.0 weighting, the Seasonal class which is entirely residential type metering is less and determined at a 0.89 weighting.

(page left blank intentionally)

7.0 – VECC – 31

Reference: E7/T1/S2/ pg.1-3

a) Please provide a schedule that compares the weighting factors used for Services, Billing & Collecting, Metering Capital and Meter Reading in this Application with those used in API's last Cost Allocation Review (EB-2009-0278).

RESPONSE:

a) Below is a schedule comparing the weighting factors used in EB-2009-0278 (2011) with those use in the current Cost Allocation Study.

Weighting Factors

	Services		Billing & Collecting		Meter Capital		Meter Reading	
	2011	2015	2011	2015	2011	2015	2011	2015
Residential - R1	1.125	1.00	1.125	1.00	1.00	1.00	1.00	1.00
Residential - R2	10.00	10.00	7.00	5.00	17.74	4.73	3.79	1.00
Seasonal	1.00	1.00	1.00	1.00	0.99	0.89	0.99	1.00
Street Lighting	0.33	0.25	1.00	1.75		-		-

(page left blank intentionally)

7.0 – VECC -32

Reference: E7/T1/S2/pg.2

a) Please clarify the paragraph at lines 5-8. If all customers provide their own "service assets":
   - Why are there any costs recorded in Acct. #1855?
   - What are the "API connection assets" referred to in the paragraph?

b) Please explain why the Seasonal class' weighting factor for meter capital is less than that for the R1 class.

RESPONSE:

a) The costs recorded in Account #1855 are primarily related to the connection assets used by API to connect and energize the service. The connection assets include the electrical connectors, terminations, clamps and all other materials required to connect the customer's service to the API distribution system.

b) API's Residential – R1 customer class is a mixture residential and small general service customer. In most Ontario LDCs these small general service customers would be classified as General Service less than 50 kW. The Seasonal customer class is comprised entirely of residential style services. Therefore, the capital meter cost of the Residential – R1 class which includes residential and small general service has a higher weighting at 1.0 when compared to the Seasonal class which is entirely residential type metering which is weighted at a 0.89 weighting.

(page left blank intentionally)

7.0 – VECC -33

Reference: Cost Allocation Model, Tabs I6.1 and O1
E6/T1/S4/Appendix A (RRWF)/Revenue
Deficiency/Sufficiency Worksheet

a) Please explain why the revenue at existing rates used in the CA Model ($20,356,651) does not match the revenue at existing rates in the RRWF ($20,640,736).
b) Please explain why, for those classes not receiving RRRP (i.e. Seasonal and Street Lighting) the existing rates used in Tab I6.1 aren't the approved rates for 2014.
c) Please correct the models as necessary.

RESPONSE:

a) The revenue from existing rates used in the Cost Allocation Model is developed from the equivalent distribution rates. This practice has been consistent since EB-2009-0278 and is required to simulate the recovery of the full recovery of revenue from rates. This methodology is necessary to account for the RRRP funding on a per class basis for proper allocation of revenue to the classes.

The practice of converting the RRRP funding to rates and rounding to two and four decimal places will introduce differences. API does not believe that these differences are impactive on the rate design and have no bearing on the rate design to recover the test year revenue requirement.

The revenue from distribution rates found in the RRWF is derived from actual 2014 tariffs and actual RRRP funding which included partial recovery of the smart meter recovery costs allocated to the Residential – R1 class.

b) API has consistently used the equivalent distribution rates since it was an accepted solution to rate design at API. The use of equivalent distribution rates provides continuity to EB-2007-0744; the proceeding that first introduced the current form of RRRP funding and rate design. API believes that this methodology should continue in order to maintain a continuity in rate design; particularly the determination of RRRP funding. It is also necessary should API and the Board move towards implementation of a form of incentive price cap regulation in the future.

c) Not required.

7.0 – VECC -34

Reference: E7/T1/S1/pg.1 and 6-11
Cost Allocation Model, Tab E1 - Categorization

a) Please confirm that in EB-2009-0278 the revenue to cost ratio for Seasonal was reduced from a Status Quo value of 149.94% to 115.0%.
b) Please provide a schedule that for the R1 and R2 classes sets out the annual rate increase approved for 2012, 2013 and 2014.
c) Please confirm that the use of the density factor (per Tab I5.1) in the cost allocation model is used solely to establish the minimum system parameters per Tab E1, lines 16-26 and that the cut off for establishing low density is <30 customers per km.
d) With respect to page 7 (lines 16-17), are API and Hydro One the only distributors with a density of less than 30 customers/km?
e) Page 7 (lines 22-23) notes that in API's 2010 CA model the density data was not input. Please re-do the 2010 CA model using the density data per the current application and provide the resulting model run.
f) How much of the difference in the all in cost of electricity for Seasonal versus R1 customers noted on page 11 is due to the R1 customers receiving RRRP?

RESPONSE:

a) API confirms that in the settlement agreement accepted in EB-2009-0278, the revenue to cost ratio for the Seasonal class was reduced from a Status Quo value of 149.94% to 115.0%.

b) The annual rate increase for the Residential – R1 and Residential – R2 classes are the RRRP Adjustment Factors provided in Exhibit 8, Tab ,1 Schedule 1, as follows:

2012 2.81%
2013 3.75%
2014 3.76%

c) Confirmed, the kM of lines entered on I5.1 is used solely for calculating Density which is used solely to establish the minimum System parameters on Tab E1. Also confirmed that the cut-off for establishing low density is 30 customers per km of line. Algoma has 6 customers per km of line.

d) According to the Ontario Energy Board 2012 Yearbook, no.

e) Please see that Attached model.

f) Under the proposed rate design, RRRP funding will cover approximately 65% of the cost allocated to the Residential – R1 class.

7.0 – VECC -35

Reference: E7/T1/S2/Appendix A (Elenchus Study)/pg.4
Cost Allocation Model, Tab I6.2 – Customer Data

a) Please reconcile the Street Lighting connection count forecast per Exhibit 3, Table 3.1.2.2 (1,018) with the device/connection values used in the Cost Allocation model (1,032/835).

RESPONSE:

a) The value of 1018 in Table 3.1.2.2 is the correct forecasted number of devices. 835 is the number of connections that the 1018 devices have to API's distribution system. 1032 is an input error; this item would not have affected the results of the Cost Allocation Study.

(page left blank intentionally)

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.

RESPONSE:

a) Consideration of line losses during both normal and contingency system configurations was one of many of the disadvantages noted on page 34 of the Distribution System Plan (Exhibit 2, Tab 3, Schedule 1, Appendix A) for the "distribution alternative" to the Echo River TS upgrade project. The Echo River TS upgrade is planned for 2017 and API has requested that in the interim, GLPT schedule any activities requiring the re-configuration of the Echo River / Northern Avenue station supplies during summer months with lower loading to minimize the increase losses associated with these re-configurations.

Also, on pages 4-5 of the Distribution System Plan, API has indicated that ongoing implementation of new business systems will allow for “increased accuracy of cost analysis for items such as line losses and avoided future costs during the project prioritization process”. While API does not expect line losses to be the sole driver of a project or program, this evaluation will assist in ensuring that the future cost of losses is evaluated appropriately in the comparison of alternatives and/or prioritization of projects.

Algoma Coalition
Rural or Remote Electricity Rate Protection

4. With respect to the amount of rate protection available pursuant to Rural or Remote Electricity Rate Protection (hereinafter "RRRP"), please explain the allotment Algoma Power receives and how this has changed over the last five (5) years.

RESPONSE:

The allotment of RRRP funding made available to API is entrenched in the Board's Decision in the matter of EB-2007-0744; a cost of service application by API's predecessor.

It may be described as follows:

- API annual revenue requirement is proposed
- All other revenue is isolated (i.e., interest income, pole rental income, etc.)
- The net revenue requirement is allocated to the customer classes; there are four
- The amounts allocated to Residential – R1 & R2 are subject to RRRP funding
- The amounts allocated to Seasonal and Street Lighting are not subject to RRRP funding
- The most recent rates for Residential R1 & R2 are indexed by the average increase for all other distributors in Ontario in the most recent rate year, the RRRP Adjustment Factor; these become the proposed rates
- The difference between the revenue requirement allocated to the Residential R1 & R2 classes and the potential revenue derived from proposed rates and forecasted customers and loads is the RRRP funding amount for the test year

- Allocated Revenue Requirement – Potential Revenue from Proposed Rates = The RRRP Funding Amount
- Rates for Seasonal and Street Lighting customers classes are designed for full recovery of the allocated revenue requirement

The revenue requirement and the RRRP funding is established in a cost of service proceeding. However, in the rate years between cost of service proceedings electricity distribution rates are established under an incentive mechanism. For API, electricity distribution rates were set under incentive regulation in 2012, 2013 and 2014. Incentive regulation for API has been designed to accommodate RRRP funding. For these three years it has worked as follows:

- The OEB establishes two key metrics for API
    1. The RRRP Adjustment Factor
    2. Price Cap Index
- For API, the electricity distribution rates of the Residential – R1 & R2 customer classes are indexed by the RRRP Adjustment Factor while the electricity distribution rates of Seasonal and Street Lighting customer classes are indexed by the Price Cap Index.
- Over the period of 2012 to 2014, the RRRP Adjustment Factor has been greater than the Price Cap Index. The result of this asymmetry of rate indexation has meant that API could potentially receive more revenue from rates than was intended under the price cap regulation (incentive regulation). To compensate for this possibility, any potential over recovery from the Residential – R1 & R2 classes (i.e., RRRP Adjustment Factor minus the Price Cap Index) is calculated and deducted from the RRRP funding available to API that rate year.

Algoma Coalition
Rural or Remote Electricity Rate Protection

5. Please explain how any increase in RRRP funding compares with Algoma Power's costs over each of the last five (5) years.

RESPONSE:

As explained in the response to the previous interrogatory, #4, API's revenue requirement and RRRP funding is approved by the OEB during a cost of service proceeding. API's last cost of service proceeding was EB-2009-0278 and electricity distribution rates were effective December 1, 2010.

The approved 2011 base revenue requirement (the revenue recovery from electricity distribution rates) was $19,828,731 and the allowed RRRP funding amount for 2011 was $11,411,951.

In this Application, API is proposing a base revenue requirement of $23,426,431 and RRRP funding of $14,515,412.

This Application applies the same methodology for determining the amount of RRRP funding as was approved by the Board in EB-2007-0744 and EB-2009-0278.

(page left blank intentionally)

Algoma Coalition
Line Losses

12. Please provide Algoma Power's current line loss value.

RESPONSE:

As outlined in Exhibit 8, Tab 2, Schedule 8 on page one, API's approved Tariff of Rates and Charges provided for a 1.0864 Total Loss Factor for secondary metered customers and a 1.0755 Total Loss Factor for primary metered customers.

(page left blank intentionally)

Algoma Coalition
Line Losses

13. Please explain how Algoma Power's line loss value has changed over each of the previous five (5) years.

RESPONSE:

Exhibit 8, Tab 2, Schedule 8, Table 8.2.8.1, Appendix 2-R Loss Factors, outlines the loss value as it has changed over the previous five (5) years. The loss values are calculated based on the Net "Wholesale" kWh delivered to the distributor divided by the Net "Retail" kWh delivered by distributor.

The increase in the Total Loss Factor over the previous five (5) years is likely due to an increase in the energy requirements and demands of two Residential – R2 customers; one being a base metal mine and the second an aggregate mine.

(page left blank intentionally)

Algoma Coalition
Line Losses

14. Please provide the forecast line loss changes over each of the next two (2) years.

RESPONSE:

API has proposed the following Loss Factors for the 2015 Test Year:

Supply Facility Loss Factor	1.0045
Total Loss Factor – Secondary Metered Customer	1.0917
Total Loss Factor – Primary Metered Customer	1.0808

If approved by the OEB, these will be consistent over the next two years.

(page left blank intentionally)

Algoma Coalition
Line Losses

15. Please confirm and detail Algoma Power's plan to minimize the line loss during the next five (5) years.

RESPONSE:

API recognizes that the loss factors determined are greater than the 5% threshold referenced in the Board's Filing Requirements for Electricity Distribution Rate Applications. API serves a very large geographic area of approximately 14,200 square kilometers with 1845 kilometers of line servicing 11,720 customers. It is generally recognized that with its very low customer density and vast service territory API's loss factor will exceed 5%.

The following activities would be expected to have secondary benefits that have positive overall impacts on API's line losses over the next five years:

- Any line rebuild work in the five-year plan that occurs in the remaining lower voltage pockets of API's system would incorporate voltage conversion.
- The Echo River TS project would improve line losses during certain contingency system configurations.

It should be noted that while the above activities will have positive impacts, the impacts will be minimal and API therefore does not expect a material reduction in losses over the next five years. It is entirely possible that load growth in areas distant from transmission supply points and/or system operating conditions over the next five years could more than offset any improvements in line losses as a result of the above activities.

(page left blank intentionally)

<u>8-Energy Probe-35</u>

Ref: Exhibit 8, Tab 2, Schedule 1 &
Exhibit 2, Tab 2, Schedule 1

Please show the calculation that results in the Residential-R1 monthly fixed charge of $24.03 shown in Table 8.2.1.4 in Exhibit 8, Tab 2, Schedule 1. In particular, please show how this figure was determined based on the current charge of $20.96 per year (Table 8.2.1.2) and the $1.89 per month charge associated with the stranded meter costs shown in Table 2.2.1.3 in Exhibit 2, Tab 2, Schedule 1. If these two latter figures are not relevant in the calculation, please explain the relevance of these figures.

RESPONSE:

The Residential – R1 proposed fixed monthly charge of $24.03 is the 2014 Board Approved tariff of $23.16 per month indexed by the estimated 2015 RRRP Adjustment Factor of 3.76%.

$24.03 = $23.16 * 1.0376

As discussed in Exhibit 8, Tab 1, Schedule 1, on page 9 of 10, the value $20.96 is the 2014 equivalent monthly service charge for the Residential – R1 class. The continuity of equivalent distribution rates is a key component of the rate design methodology accepted in EB-2009-0278; API's last cost of service proceeding. Equivalent distribution rates maintain continuity with the initial implementation of the RRRP funding model in EB-2007-0744; a cost of service proceeding for API's predecessor.

As discussed in Exhibit 8, Tab 2, Schedule 1, on page 3 of 5, the $192,509, of Stranded Assets Related to Smart Meter Deployment has been included in the revenue requirement allocated to the Residential – R1 class for recovery. Therefore, the $1.89 per month charge associated with stranded meter costs does not directly factor into the determination of the fixed monthly charge for the Residential – R1 class. The allocation to the Residential – R1 class that is not recovered through an indexing of the current approved tariff is recovered in RRRP funding.

<u>8-Energy Probe-36</u>

Ref: Exhibit 8, Tab 2, Schedule 1

a) **Please explain why the total figure shown in the second part of Table 8.2.1.4 in the last column ($6,993,505) does not appear to include the transformer allowance revenue of $74,096.**

b) **Please explain how the rural and remote rate protection amount of $14,515,412 is calculated based on the information in the table.**

RESPONSE:

The responses to parts a & b are combined and therefore have been answered in a single response. Table 8.2.1.4 on page 3 of Exhibit 8, Tab 2, Schedule 1, details the revenue allocations at the proposed revenue to cost ratios.

The top section of the table details the class allocations, those are:

Residential – R1	$17,013,843
Residential – R2	$4,228,468
Residential – R1 (stranded meters)	<u>$192,509</u>
Total Allocation	$21,434,820 (A)

In the lower section of the same table, the amount to be recovered from rates after the application of the RRRP Adjustment factor is:

Residential – R1	$5,984,952
Residential – R2	<u>$1,008,553</u>
Total Recovered from Rates post RRRP indexing	$6,993,505 (B)

There is no mechanism to add back the transformer ownership credit to the Residential – R2 class as this will result in the allocation of an amount greater than the indexing of current distribution rates by the RRRP Adjustment Factor. In the previous cost of service proceeding, EB-2009-0278, there was no form of accommodation of the transformer ownership credit to the detriment of API.

In order to accommodate the transformer ownership credit it has to be allocated to the revenue allocation of the residential – R2 class; this has been done in a transparent method as follows:

The required RRRP funding amount is:

Total Allocation	$21,434,820	(A)
Total Recovered from Rates post RRRP indexing	$6,993,505	(B)
Residential – R2 (add back of transformer ownership credit)	$74,096	(C)
RRRP Funding Required	$14,515,411	(A)–(B)+(C)

8.0 –VECC - 36

Reference: E8/T1/S1/pg.7-9

a) Please reconcile the 2011 R1 and Seasonal customer counts used in tables on pages 7 – 9 with the 2011 customer counts reported in Exhibit 3, Table 3.1.2.2.
b) Please provide corrected tables as required.
c) With respect to the first table on page 7, please explain why for those classes not receiving RRRP (i.e., Seasonal and Street Lighting), the approved 2011 rates are not used as the starting point.

RESPONSE:

a) The 2011 customer count for the seasonal class found in Table 3.1.2.2 is the Board approved value for 2011. The value of 3660 found in Exhibit 8, Tab 1, Schedule 1, is the average of the 2010 and 2011 Board Approved quantities from EB-2009-0278.

The same approach was followed for the Residential – R1 class.

b) No correction is required.

c) API has consistently used the equivalent distribution rates since it was an accepted solution to rate design at API. The use of equivalent distribution rates provides continuity to EB-2007-0744; the proceeding that first introduced the current form of RRRP funding and rate design. API believes that this methodology ought to continue in order to maintain a continuity in rate design; particularly the determination of RRRP funding. It is also necessary should API and the Board be able to implement a form of incentive price cap regulation in the future.

(page left blank intentionally)

8.0 –VECC - 37

Reference: E8/T2/S1/pg.2-5

a) Please reconcile the R1 and Seasonal 2011 customer counts used in Table 8.2.1.2 with those reported in Exhibit 3, Table 3.1.2.2.
b) Please reconcile the R1 and Seasonal 2015 customer counts used in Tables 8.2.1.3, 8.2.1.4, 8.2.1.5 and 8.2.1.6 with the 2015 forecast shown in Exhibit 3, Table 3.1.2.2.
c) Please provide revised/corrected versions of the tables in Exhibit 8 as required.
d) With respect to Tables 8.2.1.2 and 8.2.1.3, please explain why for those classes not receiving RRRP, the approved 2014 rates are not used as the starting point.
e) For both the Seasonal and Street Lighting classes please provide a schedule that calculates the fixed/variable split based on the forecast customer count and load for 2015 and the approved 2014 rates.
f) Using the fixed/variable percentages from part (e) and the requirement proposed to be recovered from each of these classes in 2015 what would be the resulting fixed and variable rates for 2015 for the Seasonal and Street Lighting classes?

RESPONSE:

a) This is essentially the same as Interrogatory 8-VECC-36; the customer counts provided in Tables 3.1.2.1 and 3.1.2.2 are year-end customer counts. The rate design tables found in Exhibit 8, Tab 2, Schedule 1, use the average customer/connections to calculate rates.

b) See the response to part a) above. The rate design tables found in Exhibit 8, Tab 2, Schedule 1, use the average customer/connections to calculate rates.

c) Not required.

d) API has consistently used the equivalent distribution rates since it was an accepted solution to rate design at API. The use of equivalent distribution rates provides continuity to EB-2007-0744; the proceeding that first introduced the current form of RRRP funding and rate design. API believes that this methodology ought to continue in order to maintain a continuity in rate design; particularly the determination of RRRP funding. It is also necessary should API and the Board be able to implement a form of incentive price cap regulation in the future.

e) A schedule showing the calculated fixed and variable split for the Seasonal and Street Lighting classes on the basis of 2014 rates is shown below.

Customer Class	UOM	Average # of Customers (Connections)	kWh	2014 Rates		Revenue		f/v Split	
				MSC	Vol.	Fixed	Variable	Fixed	Variable
Seasonal	kWh	3138	7,680,066	26.75	0.1029	1,007,298	790,279	56.0%	44.0%
St. Lighting	kWh	1018	804,690	0.98	0.1579	11,972	127,061	8.6%	91.4%

f) A schedule showing the calculated 2015 rates for the Seasonal and Street Lighting classes on the basis of part e) is shown below.

Customer Class	UOM	Average # of Customers (Connections)	kWh	2015 Revenue Requirement	Alternative 2015 Rates		Revenue		f/v Split	
					MSC	Vol.	Fixed	Variable	Fixed	Variable
Seasonal	kWh	3138	7,680,066	2,023,360	30.11	0.1158	1,133,819	889,541	56.0%	44.0%
St. Lighting	kWh	1018	804,690	160,760	1.13	0.1826	13,843	146,917	8.6%	91.4%

This rate design is not consistent with the parties' intent in the EB-2009-0278 settlement and the discussions related to incentive rate setting designs in 2012, 2013 and 2014.

8.0 –VECC - 38

Reference: E8/T2/S2/pg.1-2

a) What is the measurement interval used to determine demand for: i) the interval metered R2 customers over 1000 kVA and ii) the non-interval metered customers? For example, is the measurement period 15 minutes, 20 minutes, 60 minutes or some other interval length?
b) If the intervals used are not the same for both types of customers, please comment on the appropriateness of applying the same RTSR rates to each.

RESPONSE:

a) API has standardized on a 15 minute interval for all Residential – R2 customers.

b) Not applicable based on response to part a).

(page left blank intentionally)

8.0 –VECC -39

Reference: E8/T2/S8/pg.1-2

a) With respect to Table 8.2.8.1, why is there no consumption shown for API's large use customers (i.e. customers over 5 MW)?

RESPONSE:

a) Algoma Power does not have any customers that fall into the "Large Use" customer classification found in other Ontario distributors. Please see response to 3-Energy Probe-17 for a further discussion on API's larger customers that fall into the Residential – R2 customer class.

(page left blank intentionally)

8.0 –VECC - 40

Reference: E8/T2/S8/pg.1-2

Preamble: On page 1 API notes that distributed generation embedded in its service territory is included in the determination of the loss adjustment factors.

a) How much distributed generation is included in line C for each of the five years?
b) The calculation of the Total Loss Factor assumes that the Supply Facilities Loss Factor is applicable to all wholesale deliveries. Please explain why this is appropriate if distributed generation is included in the wholesale deliveries.

RESPONSE:

a) The following quantities of generation are included in line C:

2011 – 299,620 kWh
2012 – 877,130 kWh
2013 – 876,521 kWh

b) It is API's opinion this is not significant enough to warrant change.

(page left blank intentionally)

8.0 –VECC - 41

Reference: E8/T2/S11/pg.1 and pg. 5-6

a) Please explain why, when the revenue to cost ratios for both customer classes are being maintained at the Status Quo value, the bill impacts (e.g. Sub-Total A) for the Seasonal class are materially less than those for Street Lighting.
b) With respect to page 6, please explain the basis for the volume value of 438 as applied to the Monthly Service Charge.
c) Please explain why the 2014 Street Lighting rates used for page 6 do not include the $0.0003/kWh Rate Rider for Foregone Revenue Recovery (2013) – per Exhibit 8, Tab 2, Schedule 9 – Current Tariffs, page 4.
d) Please provide a schedule equivalent to that on page 6 but based on 150 kWh/1 kW.

RESPONSE:

a) The reference to Status Quo revenue to cost ratios is taken from the Board's prescribed Appendix 2-P. It does not refer to the revenue to cost ratios that underpin the current electricity distribution rates but rather are the revenue to cost ratios as determined by the test year cost allocation study.

Existing rate designs, based on the previous cost allocation study resulted in the Street Lighting class under-contributing while the Seasonal class was over-contributing.

The test year cost allocation study has attributed cost to the Street Lighting class that result in the rate impacts provided.

b) The volume value of 438 refers to the number of connections.

c) The Rate Rider for Foregone Revenue Recovery (2013) should have been included in the bill impact calculation.

d) A schedule showing a scenario of 150 kWh / 1 kW is shown on the following page. This exhibit is contained in Appendix 2-W accompanying the Application. This version has been updated to include the Rate Rider for Foregone Revenue Recovery (2013) referenced in part c).

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")[1]:

> *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.

RESPONSE:

a) Please refer to commentary provided in Exhibit 9, Tab 5, Schedule 1. Below is an excerpt from the Application:

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

"Due to the non-significant dollars associated with these types of revenues and expenditures, API has not followed the Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548."

b) Please refer to commentary provided in Exhibit 9, Tab 5, Schedule 1. Below is an excerpt from the Application:

"For example, OEB 4082 had $5,546 and OEB 4084 had $87 in credit revenues in 2013 (Appendix 2-H in Exhibit 3 Tab 4 Schedule 2), while offsetting debit costs totaling $2,786 were recorded within OEB 5340. The net credit of $2,847 remained in the Profit and Loss Statement for 2013."

Therefore, if API had followed the APH, a net credit total of $2,847 would have been recorded in the regulatory accounts as of December 31, 2013.

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[1] 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.*

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/

RESPONSE:

a) Due to a regulatory accounting process change with respect to the OCEB credits, the balance in this Sub-Account has changed from a debit in 2011 to credit balances in 2012 and 2013. The new process involves API estimating

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

OCEB credits to be issued one month in advance on the Independent Electricity System Operator ("IESO") monthly submissions, so that the timing of the credit received on the IESO bill is in line with the credits issued on the customer bills. There is a true-up completed, subsequently that compares the estimate submitted on the IESO form and the actual credits issued. Any difference calculated from the true-up completed is remitted to the IESO via subsequent month IESO's submission.

The increase in the credit balance between 2012 and 2013 is primarily attributable to the increase in estimated OCEB credits in January 2014 as compared to January 2013, as remitted on the monthly IESO submission in December.

b) In 2012, a correcting journal entry was recorded to adjust the regulatory interest charges from 2011. Given that this Sub-Account had a debit balance prior to 2012, the interest journal entry was a debit amount.

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.

RESPONSE:

Please see tables below that have been updated with explanations for requests in a) to c) above.

2011					
Account #	Adjustment 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)
	A	A	B	

Notes:

A In EB-2012-0104, Group 1 account balances as of December 31, 2011 were approved for disposition. In the OEB's Chapter 2 filing requirements, a continuity schedule for the period following the last disposition to the present is to be provided. API has used the 2011 adjustment column to populate opening balances so activity post December 31, 2011 can be populated in subsequent columns of the schedule.

B See comment in **A** above.

2012				
Account #	Adjustment Principal	Adjustments Interest	Directional Inconsistency between Principal and Interest	Total Adjustments 2011
1588	314,012	-	X	314,012
1589	(744,397)	46,051	X	(698,346)
1595	66,872	-	X	66,872
	(363,513)	46,051		(317,462)
	A	A	B	

Notes:

A

Account #	Adjustment Principal	Adjustments Interest	
1588	314,012	-	Fixed price adjustment true-up calculation completed in 2013 and included in the EDDVAR continuity schedules submitted in EB-2013-0110. Added to the adjustments column in 2012 as this is a true-up of 2012 activity.
1589	(677,525)	-	Global adjustment true-up calculation completed in 2013 and included in the EDDVAR continuity schedules submitted in EB-2013-0110. Added to the adjustments column in 2012 as this is a true-up of 2012 activity.
	(66,872)	46,051	Adjustment relates to the Board Decision in EB-2011-0152 where API was required to move a total credit of $66,872 out of the 1595 recovery account and back into the 1589 account. Of the total credit of $66,872, a credit of $20,821 was principal while the remaining $46,051 credit was interest. Upon further review of the continuity schedule, the credit of $66,872 in the principal adjustment column should have been reduced by $46,051 and the amount should have been recorded in the transactions during 2012 column instead. There would be no change to the ending balance of this account.
1595	66,872	-	See comment in OEB 1589 above.
Total Explained	(363,513)	46,051	

B See comment in **A** above for explanation of both principal and interest adjustments.

2013				
Account #	Adjustment Principal	Adjustments Interest	Directional Inconsistency between Principal and Interest	Total Adjustments 2011
1588	179,041	-	X	179,041
1589	(207,970)	-	X	(207,970)
	(28,930)	-		(28,930)
	A	A	B	

Notes:

	Account #	Adjustment Principal	Adjustments Interest	
A				
	1588	179,041	-	Fixed price adjustment true-up calculation completed in 2014 and included in the EDDVAR continuity schedules submitted in this Application. Added to the adjustments column in 2013 as this is a true-up of 2013 activity. See variance tab of EDDVAR workform provided in E9 T1 S2 for additional explanation.
	1589	(207,970)	-	Global adjustment true-up calculation completed in 2014 and included in the EDDVAR continuity schedules submitted in this Application. Added to the adjustments column in 2013 as this is a true-up of 2013 activity. See variance tab of EDDVAR workform provided in E9 T1 S2 for additional explanation.
	Total Explained	(28,929)	-	

B See comment in **A** above. No interest as part of adjustments explained above.

(page left blank intentionally)

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.

RESPONSE:

a) See response to 2-Energy Probe-4d.

b) The discrepancy is the corporate asset allocations.

	Under CGAAP	
	2013	2014
Additions		
Additions per continuity schedule	11,209,617	10,059,315
Disposals per continuity schedule	(795,067)	-
Allocations per current year continuity schedule	3,838,341	4,331,701
Allocations per prior year continuity schedule	(3,282,428)	(3,838,341)
Total Net Additions	10,970,463	10,552,675

c) The discrepancy is the corporate asset allocations.

	Under CGAAP	
	2013	2014
Depreciation		
Additions per continuity schedule	(6,186,296)	(5,515,430)
Disposals per continuity schedule	811,839	-
Allocations per current year continuity schedule	(2,303,720)	(2,749,624)
Allocations per prior year continuity schedule	1,985,441	2,303,720
Total Net Depreciation	(5,692,736)	(5,961,334)

d) The discrepancy is the corporate asset allocations.

	With Accounting Changes	
	2013	2014
Additions		
Additions per continuity schedule	9,940,474	8,717,338
Disposals per continuity schedule	(795,067)	-
Allocations per current year continuity schedule	3,838,341	4,331,701
Allocations per prior year continuity schedule	(3,282,428)	(3,838,341)
Total Net Additions	9,701,320	9,210,698

e) The discrepancy is the corporate asset allocations.

	With Accounting Changes	
	2013	2014
Depreciation		
Additions per continuity schedule	(4,248,144)	(3,456,790)
Disposals per continuity schedule	811,839	-
Allocations per current year continuity schedule	(2,303,720)	(2,749,624)
Allocations per prior year continuity schedule	1,985,441	2,303,720
Total Net Depreciation	(3,754,584)	(3,902,694)

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

- Ref: Exhibit 9/Tab 4/Sch. 3 (Appendix 2-EE)
- Ref: OEB - 2012 Yearbook[1] of Electricity Distributors

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.

RESPONSE:

a) The differences are that account 2055, asset under construction is included in the 2012 Yearbook and the corporate asset allocations are not included in the 2012 Yearbook.

Reconciliation of 2012 Net PP&E per Appendix 2-EE and 2012 Yearbook	
Opening Net PP&E 2013 per Appendix 2-EE	80,883,969
Add account 2055, Assets under Construction	1,908,200
Additions of asset allocations per continuity schedule	(3,282,428)
Depreciation of asset allocations per continuity schedule	1,985,441
Closing Net PP&E 2012 per 2012 Yearbook	81,495,182

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

(page left blank intentionally)

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?

RESPONSE:

a) The rates set out in the Board's rate order effective May 1, 2002 (at Exhibit 9, Tab 8, Schedule 1, Appendix A) reflected a discount of $28.50/month for customers eligible under the RRRP program. API does not propose to adjust the historic discounts received by its customers, since to do so would amount to retroactive rate making. Rather, API is seeking to recover the appropriate compensation for the RRRP discounts it provided to its customers during the period from 2002 - September, 2007 through an additional compensation payment from the RRRP funding pool administered by Hydro One. At all relevant times, subsection 79(3) of the OEB Act provided that a distributor is entitled to be compensated for lost revenue resulting from rate reductions under the RRRP program. Therefore, the compensation from HONI for which API is seeking Board confirmation is an entitlement prescribed by legislation.

b) Please refer to API's response to (a) above. Again, API is not proposing to retroactively adjust rates.

c) Please refer to API's response to (a) above.

d) API is not seeking to recover its RRRP underfunding from its rate payers, as suggested by the interrogatory. API is seeking an order from the Board confirming the amount of additional compensation that API is entitled to recover from HONI pursuant to subsection 79(3) of the OEB Act. A deferral account is not required for API to recover this prescribed compensation.

e) API raised this issue in its last cost of service application, but the issue did not form part of the settlement agreement in that proceeding.

(page left blank intentionally)

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.

RESPONSE:

a) API is not opposed to a 2-year disposition period. However, due to volatility which is often associated with the Global Adjustment Sub-Account, a 2-year disposition may have the undesired effect of introducing greater volatility in a second year of a multi-year disposition.

b) A 2-year disposition period will essentially reduce the rate rider by 50%; the resultant comparative bill impacts are provided below:

One year Disposition per the Application Exhibit 8, Tab 2, Schedule 11

Summary of Bill Impacts - Extracted from Appendix 2-W

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**		31.36	32.03	2.14%	34.07	31.63	-7.15%	37.36	35.02	-6.26%	62.94	60.57	-3.77%
		800		49.40	49.63	0.47%	56.34	46.62	-17.24%	66.85	57.45	-14.06%	147.26	137.72	-6.48%
		1,500		72.36	72.03	-0.46%	84.67	65.70	-22.41%	104.39	86.01	-17.61%	254.56	235.92	-7.32%
		2,000		88.76	88.03	-0.82%	104.92	79.33	-24.39%	131.21	106.40	-18.90%	331.22	306.50	-7.60%
		5,000		187.16	184.03	-1.67%	226.36	161.09	-28.84%	292.09	228.78	-21.68%	791.13	726.88	-8.12%
		10,000		351.16	344.03	-2.03%	428.78	297.36	-30.65%	560.23	423.73	-22.76%	1,557.64	1,428.28	-8.31%
		15,000		515.16	504.03	-2.16%	631.19	433.63	-31.30%	828.37	636.69	-23.14%	2,324.16	2,129.68	-8.37%
Residential - R2	**Non-RPP**	**30,000**	**50**	751.76	720.51	-4.16%	983.71	1,117.08	13.56%	1,221.90	1,375.32	12.56%	4,692.47	4,866.85	3.72%
		81,000	**160**	1,094.15	994.15	-9.14%	1,720.44	2,140.10	24.39%	2,482.64	2,966.46	19.49%	11,746.54	12,296.03	4.68%
		90,000	**225**	1,296.48	1,155.85	-10.85%	1,992.35	2,571.17	29.05%	3,064.20	3,733.23	21.83%	13,397.13	14,156.21	5.67%
		4,100,000	**6,000**	19,272.32	15,522.32	-19.46%	50,973.26	67,214.68	31.86%	79,555.79	98,203.02	23.44%	542,461.25	563,672.58	3.91%
R2, Interval	**Non-RPP**	**90,000**	**225**	1,296.48	1,155.85	-10.85%	1,992.35	2,571.17	29.05%	3,148.85	3,733.23	18.56%	13,492.79	14,156.21	4.92%
Seasonal	**RPP-TOU**	**287**		73.32	78.83	7.50%	76.32	78.25	2.53%	80.09	82.14	2.56%	110.05	112.14	1.90%
		1,000		168.51	193.69	14.94%	176.98	189.73	7.20%	190.13	203.27	6.91%	292.37	305.77	4.58%
Street Lighting	**Non-RPP**	**150**	**1**	24.67	28.43	15.26%	25.82	30.74	19.04%	29.45	34.47	17.05%	50.12	55.80	11.33%
		25,000	**71**	4,366.94	4,994.44	14.37%	4,560.24	5,379.60	17.97%	4,817.94	5,644.71	17.16%	8,204.08	9,139.18	11.40%

Two Year Disposition

Summary of Bill Impacts - Extracted from Appendix 2-W - 9Staff42 - Disposion Period

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**		31.36	32.03	2.14%	34.07	33.25	-2.42%	37.36	36.63	-1.95%	62.94	62.21	-1.16%
		800		49.40	49.63	0.47%	56.34	51.78	-8.08%	66.85	62.61	-6.34%	147.26	142.96	-2.92%
		1,500		72.36	72.03	-0.46%	84.67	75.38	-10.98%	104.39	95.68	-8.34%	254.56	245.75	-3.46%
		2,000		88.76	88.03	-0.82%	104.92	92.23	-12.09%	131.21	199.30	-9.07%	331.22	319.18	-3.64%
		5,000		187.16	184.03	-1.67%	226.36	193.34	-14.59%	292.09	261.03	-10.64%	791.13	759.69	-3.97%
		10,000		351.16	344.03	-2.03%	428.78	381.86	-15.61%	560.23	497.23	-11.25%	1,557.64	1,493.88	-4.09%
		15,000		515.16	504.03	-2.16%	631.19	530.38	-15.97%	828.37	733.44	-11.46%	2,324.16	2,228.07	-4.13%
Residential - R2	**Non-RPP**	**30,000**	**50**	751.76	720.51	-4.16%	983.71	1,041.89	5.91%	1,221.90	1,300.12	6.40%	4,692.47	4,781.88	1.91%
		81,000	**160**	1,094.15	994.15	-9.14%	1,720.44	1,899.48	10.41%	2,482.64	2,725.84	9.80%	11,746.54	10,640.81	2.36%
		90,000	**225**	1,296.48	1,155.85	-10.85%	1,992.35	2,232.79	12.07%	3,064.20	3,394.85	10.79%	13,397.13	137,773.85	2.81%
		4,100,000	**6,000**	19,272.32	15,522.32	-19.46%	50,973.26	58,191.28	14.16%	79,555.79	89,179.62	12.10%	542,461.25	553,476.14	2.03%
R2, Interval	**Non-RPP**	**90,000**	**225**	1,296.48	1,155.85	-10.85%	1,992.35	2,232.79	12.07%	3,148.85	3,394.85	7.81%	13,492.79	13,773.85	2.08%
Seasonal	**RPP-TOU**	**287**		73.32	78.83	7.50%	76.32	83.00	8.74%	80.09	86.89	8.47%	110.05	117.14	6.26%
		1,000		168.51	193.69	14.94%	176.98	206.29	16.52%	190.13	219.82	15.90%	292.37	323.19	10.30%
Street Lighting	**Non-RPP**	**150**	**1**	24.67	28.43	15.26%	25.82	30.20	16.95%	29.45	33.93	15.21%	50.12	55.19	10.11%
		25,000	**71**	4,366.94	4,994.44	14.37%	4,560.24	5,289.06	15.99%	4,817.94	5,554.71	15.29%	8,204.08	9,037.48	10.16%

9-Energy Probe-37

Ref: Exhibit 9, Tab 9, Schedule 1

Please explain how the additional $760,467 that was accumulated beyond the amount designated to be disposed of was calculated.

RESPONSE:

In EB-2009-0278, API requested and received approval to dispose of the deferral amount associated with the Seasonal rate class. The request made in EB-2009-0278 included amounts accrued to December 31, 2009. In the Board's Decision and Order in the matter of EB-2009-0278, the rate rider approved to dispose of the deferral amount was implemented on December 1, 2010. In the eleven month period from December 31, 2009 to December 1, 2010; the implementation date, the deferral amount associated with the Seasonal rate class continued to accumulate. In that eleven month period, an additional $760,467 beyond the amount designated to be disposed of in EB-2009-0278 was incurred.

(page left blank intentionally)

9.0 –VECC - 42

Reference: E9/Appendix 2-EE

a) Please explain the reason for a 5 year disposition of Account 1576 (PP&E Adjustment).
b) Please recalculate the rate rider based on a 2 year disposition.

RESPONSE:

a) The following is an excerpt from Exhibit 9, Tab 4, Schedule 1 of the Application:

> *"API requests a five year disposition period to match with the period until the next rebasing."*

The 5 year disposition period was applied in an effort to mitigate the bill impact for customers.

b) Please see below for revised Appendix 2-EE, adjusted to 2 years of return on rate base calculated using a WACC of 6.71%. Also, please see below for re-calculated rate riders based on a 2 year disposition period.

Appendix 2-EE
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2011 Rebasing Year"	2012	2013	2014	2015 Rebasing Year	2015	2016	2017	2018
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
			$	$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1			80,883,969	86,161,697					
Net Additions - Note 4			10,970,463	10,552,674					
Net Depreciation (amounts should be negative) - Note 4			(5,692,735)	(5,961,334)					
Closing net PP&E (1)			86,161,697	90,753,037					
PP&E Values under revised CGAAP (Starts from 2012)									
Opening net PP&E - Note 1			80,883,969	86,830,705					
Net Additions - Note 4			9,701,320	9,210,698					
Net Depreciation (amounts should be negative) - Note 4			(3,754,585)	(3,902,694)					
Closing net PP&E (2)			86,830,705	92,138,709					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			(669,008)	(1,385,671)					

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	(1,385,671)	**WACC**	6.71%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	(185,957)		
Amount included in Deferral and Variance Account Rate Rider Calculation	(1,571,629)	**# of years of rate rider disposition period**	2

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2013, the PP&E values as of January 1, 2013 under both

2 Return on rate base associated with Account 1576 balance is calculated as:
the variance account opening balance as of 2014 rebasing year x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years) 2

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Accounts 1575 and 1576	Rate Rider for Accounts 1575 and 1576	
Residential R1	kWh	104,826,589	-$ 838,489	- 0.0040	$/kWh
Residential R2	kW	198,897	-$ 665,271	- 1.6724	$/kW
Seasonal	kWh	7,680,066	-$ 61,431	- 0.0040	$/kWh
Street Lighting	kWh	804,690	-$ 6,437	- 0.0040	$/kWh
Total			**-$ 1,571,628**		

9.0-VECC- 43

Reference: E9/T8/S1/pg.8

a) Please confirm that API is seeking to recover amounts which was over-refunded to customers. Please confirm that API (or its predecessor) was only to refund to eligible customers the fixed amount of $2,333,808 on an annual (pro-rated) basis. Did API (or its predecessor) err in providing a larger refund than was contemplated under the RRRP funding model?
b) Please explain why API is only now seeking to recover a variance that originates in 2002 and ended in 2007?
c) Please provide the Board variance account order which authorized the recording of this variance.

RESPONSE:

a) API does not confirm this assertion as API's customers were not over-refunded. The $28.50/month RRRP discount provided to eligible customers was correct. Rather, the funding from the Hydro One administered pool to compensate API for the $28.50/month discount was insufficient.

b) As set out in the evidence, this issue was raised in API's last cost of service application.

c) Please refer to API's response to Board staff interrogatory 41(d).

(page left blank intentionally)