EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

2020 Cost of Service

Algoma Power Inc.
EB-2019-0019

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1.2 INTRODUCTION AND EXECUTIVE SUMMARY

1.2.1 INTRODUCTION

Algoma Power Inc. (“API”) is pleased to present its Cost of Service application (the “Application”) for rates effective January 1, 2020. This application consists of the following Exhibits, and live Excel models in support of the evidence presented in this Application.

Exhibits:

- Exhibit 1: Administrative Documents
- Exhibit 2: Rate Base and DSP
- Exhibit 3: Revenues
- Exhibit 4: Operating Expenses
- Exhibit 5: Cost of Capital and Capital Structure
- Exhibit 6: Revenue Requirement
- Exhibit 7: Cost Allocation
- Exhibit 8: Rate Design
- Exhibit 9: Deferral and Variance Accounts

Models:

- API 2020 Benchmarking Forecast Model
- API 2020 Cost Allocation
- API 2020 LRAMVA Workform
- API 2020 PILs Workform
- API 2020 Rev Requirement Workform
- API 2020 RTSR Workform
- API 2020 Load Forecast Model
- API 2020 COS Checklist
- API 2020 DVA Continuity Schedule

- API 2020 GA Analysis Workform
- API 2020 1595 Workform
- API 2020 Chapter 2 Appendices
- API 2020 Fixed Asset Continuity Schedules and Depreciation Schedules (Appendices 2-BA and 2-C)
- API 2020 Chapter 5 Appendix
- API 2020 Rate Design Model
- API 2020 Bill Impact Model
- API 2019 and 2020 Tariff Sheets
- API 2020 Advanced Capital Module

All documents and models have been submitted to the OEB via the RESS filing system.

The application along with all supporting evidence will also be posted on the API's website once the application is posted on the OEB website.

1.2.2 SUMMARY OF APPLICATION INTENDED FOR API CUSTOMERS

A brief, plain-language summary of the application is included as Appendix 1A. The summary will be posted as a stand-alone document on the OEB's website for review by the general public and be made available to customers of API via its website and social media. API has also included this summary as a stand-alone pdf file to aid in website posting of this document.

1.2.3 EXECUTIVE SUMMARY AND BUSINESS PLAN

Algoma Power Inc. ("API") has developed a Business Plan, included as Appendix 1B, to address the expectations of the OEB's *"Handbook for Utility Rate Applications"*, issued October 13, 2016.

Key elements of the Application and Business Plan are:

1) Identification of six strategic customer focused objectives, that drive capital and O&M plans and related investments over the 2020-2024 period:
    a. Sustaining End of Life Asset Replacement
    b. Sustaining Vegetation Management
    c. Worker and Public Safety and Environmental Protection
    d. Reliability Improvement – Focus on Reducing Outage Duration
    e. Facilities Improvements to Support Productivity and Efficiency
    f. Flexible Approach to Emerging Technology and Public Policy
2) A Distribution System Plan ("DSP") with projects and programs aligned with the strategic objectives listed above;
3) API's goals for the 2020-2024 period are to implement its planned projects and programs that are aligned with the objectives identified above, and to meet or exceed all targets for performance metrics identified in the DSP and the Business Plan;
4) Enhanced customer engagement to ensure that the preferences of API's customers were identified and considered in determining the strategic objectives listed above;
5) Evaluation and forecasting of performance metrics that are consistent with the OEB's Renewed Regulatory Framework ("RRF");
6) Request for the Advanced Capital Module ("ACM") treatment of a large substation project in 2021 and a large facility project in 2022;
7) An alternative proposal for ACM cost recovery to allow alignment of OEB policy with the Rural and Remote Rate Protection ("RRRP") framework, which is designed to limit distribution rate increases for the majority of API's customers;

8) Complete integration of assets and customers that API proposes to acquire from Dubreuil Lumber Inc. ("DLI"), in a manner that does not increase costs to API's existing customers;
9) A request for the OEB to extend certain exemptions in API's Distribution Licence in order to ensure that API is not required to make uneconomic investments in additional smart metering infrastructure;
10) A request for the OEB to make decisions on items 6 to 8 above as Preliminary Issues in this Application;
11) A 2020 Cost Allocation Study that incorporates the OEB's changes to cost allocation policy for Street Lighting, and increases asset categorization for bulk delivery, to more accurately allocated API's costs in a manner that reduces recent upward rate pressure on the Seasonal and Street Lighting rate classes; and,
12) Rate-setting approaches that are consistent with historical OEB-approved approaches to ensure alignment between OEB policies and the RRRP framework.

1.3 ADMINISTRATIVE

1.3.1 CONTACT INFORMATION AND COMMUNITY VENUE

Application contact information is as follows:

Applicant's Name:	Algoma Power Inc.
Applicant's Address:	1130 Bertie Street
	P.O. Box 1218
	Fort Erie, Ontario L2A 5Y2
	Phone: (905) 871-0330
	Fax: (905) 994-2207
Applicant Primary Contact:	Gregory Beharriell
	Manager Regulatory Affairs
	Email: regulatoryaffairs@fortisontario.com
	Phone: (905) 871-0330 ext. 3278
Applicant's Counsel:	Michael Buonaguro
	24 Humber Trail
	Toronto, Ontario M6S 4C1
	Email: mrb@mrb-law.com
	Phone: (416) 767-1666

Community Based Venue:	Given the extent of API's service area, the preferred venue(s) for one or more community meeting(s) will depend on the number of meetings that the OEB intends to hold. Suggested venues include the Michipicoten Memorial Community Centre in Wawa,[1] and the Bruce Mines Community Hall in Bruce Mines.[2] Additionally, both the Algoma District School Board and the Huron Superior District School Board allow for community use of schools[3], and a number of schools throughout API's service area would be suitable venues for community meetings. API will work with OEB staff to narrow down potential venues and dates and to make appropriate staff available, upon confirmation of the number of community meetings. API acknowledges that it will be required to advertise these meetings and to prepare presentation materials.

1.3.2 CONFIRMATION OF INTERNET ADDRESS

The application will be posted on API's website address at www.algomapower.com and a message to that effect will be posted on the utility's website, Facebook page (https://www.facebook.com/AlgomaPower/) and Twitter site (https://twitter.com/apipower).

[1] https://wawa.cc/service/community-services-2/facilities
[2] https://huronshores.ca/venue/bruce-mines-town-hall/
[3] ADSB: http://www.adsb.on.ca/community/SitePages/Community%20Use%20of%20Schools.aspx
HSCDSB: http://www.hscdsb.on.ca/?page_id=5002

1.3.3 STATEMENT OF PUBLICATION

The persons affected by this Application are all of the ratepayers of API. It is impractical to set out their names and addresses because they are too numerous.

API proposes that Notice of Application (the “Notice”) be published in The Sault Star, which is the English-language newspaper having the highest paid circulation in API’s service territory. API also recommends that the Notice be published in the Wawa Algoma News Review.

Interested parties can also view the application on API’s website at www.algomapower.com.

1.3.4 LEGAL APPLICATION

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

AND IN THE MATTER OF an application by Algoma Power Inc. for an Order or Orders, pursuant to section 78 of the Act, approving or fixing just and reasonable distribution rates effective January 1, 2020;

AND IN THE MATTER OF an application by Algoma Power Inc. for an Order, pursuant to section 74 of the Act, amending the applicant's electricity distribution licence (EB-2009-0072) to update Schedule 3 to extend the expiration date of certain exemptions from the Distribution System Code and the Standard Service Supply Code.

API is a licensed distributor of electricity under distribution license ED-2009-0072 issued by the Ontario Energy Board (the "OEB" or the "Board") under the Ontario Energy Board Act, 1998 (the "Act").

This Application is made in accordance with the Chapter 2 (Cost of Service) and Chapter 5 (Consolidated Distribution System Plan) of the Board's Filing Requirements for Electricity Distribution Rate Applications dated July 12, 2018 (the "Filing Requirements"), except as noted in Section 1.3.11. API accordingly applies to the Board for the following Order or Orders:

1) Approval to charge distribution rates effective January 1, 2020 to recover a base revenue requirement of $25,885,176, which includes a revenue deficiency of $2,192,853 as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8;
2) Approval of the 2020 RRRP Adjustment Factor and the 2020 RRRP Funding amount payable to API, as described in Exhibit 8;

3) Approval to adjust the Retail Transmission Rates – Network and Connection as calculated in Exhibit 8;
4) Approval of the proposed loss factors as calculated in Exhibit 8;
5) Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the Board Decision and Order in the matter of EB-2018-0294;
6) Approval of the Distribution System Plan included in Exhibit 2;
7) Approval of the rate riders for disposition of the Deferral and Variance Accounts, including LRAMVA, as detailed in Exhibit 9;
8) Approval for Advanced Capital Module ("ACM") treatment of the 2021 Echo River TS Project and the 2022 Sault Facility Project, as described in Exhibit 2 and the DSP;
9) Approval of API's proposed approach for ACM cost recovery in consideration of the RRRP framework, as detailed in Section 1.3.5; and,
10) Such other approvals that API may request and that the OEB accepts.

In addition to the approvals requested above, API requests that the OEB make determinations on the following items as Preliminary Issues, in advance of processing the Application in its entirety, since decisions on these issues are time-sensitive and/or could require API to make material amendments to the Application:[4]

11) Approval of an amendment of API's electricity distribution licence (EB-2009-0072) to extend the expiry date of certain Distribution System Code and Standard Service Supply Code exemptions to December 31, 2024, as detailed in Section 1.3.6;
12) Approval of API's methodology for allocating costs attributable to the Dubreuilville service area, as summarized in Section 1.3.7;
13) Approval of API's methodologies with respect to ongoing disposition of the Interim Licence Deferral account and with respect to recovery of costs recorded in the

[4] The time-sensitivity and/or requirement for material amendments in relation to each the approvals requested in items 11 through 14 is summarized in Sections 1.3.6 through 1.3.8.

Transaction and Integration Costs Deferral Account, both in relation to the Dubreuilville service area, as summarized in Section 1.3.7; and,

14) Approval, on an interim basis, to continue charging Seasonal rate class customers a rate rider of $0.0307/kWh related to the Disposition of Account 1574 that would otherwise expire on June 30, 2019, pending the OEB's determination on further disposition of the residual balance in this account, as summarized in Section 1.3.8.

A full list of approvals is presented in PDF format at Appendix 1C of this Exhibit. For clarity with respect to items 12 and 13 above, API requests that the OEB approve the cost allocation and recovery methodologies for each category of DLI-related costs. A review of the prudence and categorization of any specific costs could be determined during the remainder of the proceeding.

Certification of accuracy and completeness of application:

API certifies that the Application has been reviewed and approved by the Vice President Finance and Chief Financial Officer. A signed certification statement is included as Appendix 1D.

Confidential Information:

API confirms that the application does not include any confidential information.

1.3.5 ACM COST RECOVERY IN CONSIDERATION OF RRRP

The OEB's Advanced Capital Module ("ACM") allows LDCs to identify discrete projects in its DSP that qualify for ACM treatment. This approach allows for prudence review during the cost of service proceeding for discrete capital projects above a materiality threshold that are planned to come into service during the IRM period.

API has identified two such projects, the 2021 Echo River TS Project and the 2022 Sault Facility Project, as summarized in Section 2.5.4. In the normal course, assuming that the OEB approves ACM treatment for these projects, API would seek approval of ACM rate riders as part of its IRM applications for the 2021 and 2022 rate years. The calculation of these rate riders is based on the incremental revenue requirement resulting from the discrete ACM projects, which approximates the effect of bringing these projects into rate base for the year in which they come into service as opposed to the next rebasing year. The rate rider approach provides for administrative and regulatory efficiency, providing for a relatively simple mechanic for the recovery of the incremental cost impacts associated with eligible capital projects. This approach also facilitates true-up calculations during the next cost of service proceeding in the event that amounts collected through rate riders differ significantly from the actual incremental revenue requirement.

For most LDCs, customers should be indifferent between the use of rate riders as opposed to adjustments to base rates, since the bill impact would be approximately the same under either approach. In contrast, the majority of API's customers are eligible for rate protection under the RRRP and DRP frameworks, as further detailed in Exhibit 8. The RRRP framework provides funding of the difference between the revenue requirement allocated to API's R1 and R2 rate classes, and the forecasted revenue received from base distribution rates from those classes. Further, the DRP framework effectively caps the monthly distribution charge payable by residential customers, on the basis of base distribution rates only. Since the impact of rate riders is not considered in either of these frameworks, traditional ACM rate riders would negatively impact customers in API's R1 and R2 rate classes. In the absence of an alternative approach to cost recovery of ACM projects, as described below, API would be incented to cluster any discrete capital projects in its bridge and test years, in order to minimize the resulting bill impact to its customers. This would be contrary to the stated intent of the OEB's ICM/ACM framework.

The OEB can find precedent for deviating from its typical rate-setting policies in API's historical IRM rate-setting applications. In these applications, instead of applying the OEB's price cap adjustment index to escalate base distribution rates for all rate classes, API applies the adjustment to the revenue requirement for the R1 and R2 rate classes. Rates for these classes are adjusted by the RRRP Adjustment Factor, and RRRP funding is calculated as the difference between:

1) The revenue requirement for the R1 and R2 customer rate classes, increased from the most recently approved test year amounts, by applying the OEB's price cap adjustment index for any subsequent IRM years; and

2) The revenues generated by the R1 and R2 rate classes, calculated by increasing the most recently approved rates adjusted by the annual RRRP Adjustment Factor, and applying these adjusted rates to the most recently approved test year load forecast.

The above deviation from typical IRM rate setting in API's circumstances, which has been approved by the OEB since 2012 (EB-2011-0152), allows the intent of the OEB's Incentive Regulation framework to be applied to API's customers in a manner that is consistent with the RRRP regulatory framework. Similarly, API proposes an alternative approach to cost recovery that would also allow API to apply the OEB's ICM/ACM framework for funding of capital investments in a manner that is consistent with the RRRP framework. Specifically, API proposes that the following steps would be applied to recover the incremental revenue requirement associated with its ACM projects:

1) API would populate the OEB's Capital Module Applicable to ACM and ICM to determine rate riders for each rate class, without consideration of RRRP. For clarity, in populating the model, the input rates for the R1 and R2 rate classes would be "Equivalent Rates", which are the rate that would apply to these rate classes in the absence of RRRP, as detailed in Exhibits 7 and 8;

2) The rate riders calculated in Step 1 would be added to the tariff for API's Seasonal and Street Lighting rate classes, which are not eligible for RRRP;

3) API would increase the revenue requirement for the R1 and R2 rate classes, by the amount of the incremental revenue calculated for those classes by the OEB model (i.e. the dollar amount used to calculate rate riders) – this increase would be applied after the

revenue requirement for these classes was escalated from the 2020 test year by the price cap adjustment index for any subsequent IRM years;

4) API would calculate the increases to base distribution rates for the R1 and R2 rate classes by applying the annual RRRP Adjustment Factor in the normal course;

5) The amount of RRRP funding for the IRM year would be calculated consistent with API's historical approach, with the revenue requirement component having been both escalated by price cap index adjustments, and increased by the incremental ACM revenue allocated to the R1 and R2 rate classes.

As a result of the above approach, rates for residential customers (as well as those customers deemed residential for the purpose of RRRP eligibility as discussed in Exhibit 8) would continue to increase by the average rate of rate increases for other LDCs, consistent with the intent of the RRRP framework. In the absence of this alternative approach, API expects that the future rate rider for a typical R1 customer resulting from the two ACM projects in this application would be in the range of $11 per customer per month. API notes that the Distribution Rate Protection Program that sets maximum monthly distribution charges for residential customers would not provide any rate relief since the maximum amount applies to base distribution rates and excludes rate riders.

1.3.6 EXTENSION OF CODE EXEMPTIONS IN LICENCE

On June 11, 2015, API applied to the OEB (EB-2015-0199) for an amendment to its Electricity Distribution Licence (EB-2009-0272) relating to provisions of the Standard Supply Service Code setting a mandatory date for implementation of time of use ("TOU") billing, and provisions of the Distribution System Code related to billing accuracy and limiting estimated bills. The essence of API's application was that while it had installed smart meters for all services in the required customer classes, for a small subset of its customers in very remote and low-density areas it was not economically possible to transition to TOU billing. API identified that for each area not covered by its AMI infrastructure at the time, the cost to implement TOU billing would range from $2,000-$10,000 per meter in initial capital costs and $500-5000 per meter in annual O&M costs.

In its October 8, 2015 Decision and Order, the OEB amended API's Licence to include the requested code exemptions, effective until December 31, 2019, as proposed by API. While API indicated that it expected to transition few, if any, additional customers to TOU billing in the 2016-2019 period, it committed to engaging and reporting progress on this item as part of the annual stakeholder sessions agreed to in its EB-2014-0055 Settlement Proposal.

As of the filing date of this Application, API has not been able to identify cost-effective solutions for transitioning the majority of its customers with hard to reach meters to TOU billing. While the cost effectiveness of communication options has improved in some areas, the capital and ongoing maintenance cost of AMI collectors that would be required for a large number of very low-density areas remains a barrier. In order to cost-effectively collect hourly reads and transition to TOU billing for these customers, API expects that a combination of solutions would be required, as follows:

1) Cost-effective communications options would need to be available – these alternatives are becoming increasingly available in API's service area; AND,

2) The costs of capital infrastructure, in consideration of the number of meters/accounts would need to be reasonable – since this is unlikely to occur through natural customer growth and API's existing AMI solution does not offer cost-effective solutions for very small/isolated groups numbers of meters, API Will, as it implements MIST metering, explore whether similar technology can be used to cost-effectively collect TOU readings for residential and small commercial customers and whether these readings can be integrated with the IESO's MDM/R system outside of API's AMI system.

Since API does not currently have a cost-effective solution for transitioning its remaining customers with hard to reach meters to TOU billing, it is requesting that the code exemptions included in Section 4 of Schedule 3 of its Distribution Licence (ED-2009-0072) be extended to December 31, 2024, coinciding with the end of its next rate-setting term.

In the event that the OEB does not approve this extension in a timely manner, API would need to spend a material amount of capital in 2019 to ensure compliance with its licence. This would require API to amend the Application to increase its 2020 rate base as well as its 2020 O&M costs related to the ongoing operation and maintenance of AMI infrastructure.

1.3.7 ALLOCATION AND RECOVERY OF DLI-RELATED COSTS

API was appointed as the interim operator of the Dubreuil Lumber Inc. ("DLI") distribution system on April 4, 2017, pursuant to section 59 of the Act, after DLI advised the OEB that it would not be able to continue providing distribution service due to financial and staffing issues (EB-2017-0153). Subsequent to becoming the interim operator of the DLI system, and with a view to addressing the OEB's preference for finding a long-term solution, API and DLI entered into discussions regarding, and ultimately entered into, an Asset Purchase Agreement (the "APA"). The APA, which is dated August 27, 2018, contemplates the sale to API of DLI's distribution system, substantially in its entirety. DLI and API applied to the OEB on September 24, 2018 for approvals in connection with the APA and the incorporation of DLI's electricity distribution system into API's existing business (EB-2018-0271; the "MAAD Application"). The OEB approved the transaction and related matters in its Decision and Order dated April 4, 2019 (the "MAAD Decision").

This cost of service application is consistent with the cost allocation and cost recovery proposals put forward by API in the MAAD Application to ensure that API's existing customers would not be harmed, and to mitigate the bill impacts for the acquired customers. While the MAAD Decision approved the interim disposition of an existing Interim Licence Deferral Account[5] and the creation of a new Transaction and Integration Costs Deferral Account, it did not provide the

[5] Subject to review of additional bill impact analysis to be included in API's Draft Rate Order

certainty required by API with respect to the entirety of the cost allocation and cost recovery proposals put forward in the MAAD Application. Specifically, the MAAD Decision found that the cost allocation proposal should be determined by the OEB panel in the current Application (as described below), and was silent on the details of specific cost recovery proposals put forward by API. API requests that the panel in the current Application address the cost allocation and cost recovery methodologies described in the subsections below as Preliminary Issues. It is important for these aspects to be addressed as Preliminary Issues because a material portion of the revenue requirement requested for the 2020 test year is tied to these cost recovery methodologies, and any changes to the proposed methodologies could significantly impact the cost allocation, bill impact and rate rider calculations contained in this Application, particularly with respect to the acquired customers. API further notes that without certainty on the outcome of these proposals, it is unable to close the commercial transaction with DLI. Since all elements of the current Application and the DSP reflect the full integration of DLI's distribution system and customers effective January 1, 2020, the OEB's decision on these Preliminary Issues is a critical prerequisite to processing the balance of the current Application. Following the OEB's decision on Preliminary Issues, API expects to be in a position to close the commercial transaction in advance of the requested effective date, and to confirm this intent with the OEB so that the Application can continue to be processed on the basis of full integration of DLI's distribution system and customers.

Cost Allocation

Based on the fact that all existing DLI customers are classified as either residential or commercial, API proposed that, in its 2020 cost allocation study, any costs that can be specifically attributed to the DLI service area would be allocated primarily to API's R1 and R2 rate classes. API further clarified through responses to IRs in the MAAD Application that it would be appropriate to allocate a small portion of such costs to the Street Lighting rate class to recognize that there are currently unbilled street lights in the DLI service area, and that API would begin receiving revenue from a newly created Street Light account for the Township of

Dubreuilville. The details of how API included this approach in the Cost Allocation Study underpinning the current Application are provided in Section 7.2.1 of Exhibit 7.

In the MAAD Decision, the OEB found that API's cost allocation proposal is a matter that should be determined by the OEB panel in the current Application, but agreed with API that its approach to integrating DLI costs into API's revenue requirement should be done in a manner that ensures there is no harm to API's existing customers. API's proposed methodology allocates DLI-specific costs directly to rate classes in proportion to customer counts and load in Dubreuilville, such that over 99% of these costs are allocated to rate classes that are RRRP-eligible. This methodology therefore integrates costs in a manner that does not harm API's existing customers. API requests that the panel in the current Application determine, as a Preliminary Issue, that the proposed methodology is appropriate. For clarity, API acknowledges that the specific allocation percentages and costs could be subject to review and approval beyond the preliminary stage of the proceeding.

Cost Recovery

In Exhibit F-3-1 of the MAAD Application, API identified that certain costs recorded or forecasted to be recorded in its Interim Licence Deferral Account were of a one-time nature, and should be excluded from the calculation of rate riders for recovery of costs from DLI customers. These costs were generally related to compliance with certain aspects of the OEB's order appointing API as the interim operator of DLI's distribution system as well as integration and one-time costs that were necessary for API to become the interim operator and ramp up compliance in a number of areas. API proposed to transfer these amounts to the Transaction and Integration Costs Deferral Account, and to dispose of all costs recorded in that account as part of its next rebasing application. In Exhibit F-3-2 of the MAAD Application, API proposed to recover the costs recorded in the Transaction and Integration Costs Deferral Account in the same manner as it recovers other one-time regulatory costs, specifically by including one fifth of the forecasted account balance (including accumulated interest) in its 2020 test year revenue requirement. Sections 4.6.2 and 4.6.3 of Exhibit 4 discuss how these costs have been included in the current Application. API requests that the OEB approve this methodology as a Preliminary Issue. For clarity, API acknowledges that review of the prudence of specific costs and the accuracy of any forecasts would be subject to review and approval beyond the preliminary stage of the proceeding. As noted in Section 4.6.2, the forecasted account balance of approximately $551,000 (from Exhibit F-3-2 of the MAAD Application) is subject to a number of adjustments, some of which depend on the final outcome of the EB-2018-0271 proceeding. API commits to making any required adjustments pending the outcome of the EB-2018-0271 proceeding, updates to forecasts as required during the progression of the current proceeding and the OEB's decision on Preliminary Issues in the current Application.

To further limit the rate rider and resulting bill impacts to DLI customers, API also proposed in Exhibit F-3-1 of the MAAD Application to transfer the net book value of the 2017-2019 capital investments in the DLI system into its rate base in 2020, such that the recovery of capital costs recorded in the Interim Licence Deferral Account would be limited to depreciation expense and cost of capital associated with 2017-2019 capital investments. Section 2.5.6 of Exhibit 2 describes how the net book value of these assets will be included in API's rate base in 2020. API requests that the OEB approve this methodology as a Preliminary Issue. For clarity, API acknowledges that review of the prudence of specific costs and the accuracy of any forecasts would be subject to review and approval beyond the preliminary stage of the proceeding.

API notes that the rate rider of $11.16/month approved in the MAAD Application is based on the cost recovery proposals described above. In its May 3, 2019 submissions on API's Draft Rate Order, OEB staff recognized that this rate rider includes these approaches to cost recovery as mitigation measures.[6] OEB staff submitted that API's proposal for a fixed rate rider of $11.16/month for six years is the most reasonable approach for balancing the disposition period and the costs incurred, relative to the impacts on customers.[7]

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[6] EB-2018-0271, OEB Staff Submission on Draft Rate Order, p. 9
[7] EB-2018-0271, OEB Staff Submission on Draft Rate Order, p.11

1.3.8 CONTINUATION OF ACCOUNT 1574 RATE RIDER (SEASONAL CLASS)

In API's 2015 cost of service application, EB-2014-0055, API proposed to extend the sunset date on the rate rider from November 30, 2015 to June 30, 2019. The date of the extension was based on continuing the rate rider at the historical amount of $0.0307/kWh, with consideration of the account balance and the forecasted load for the Seasonal class, as further detailed in Section 9.11.2 of Exhibit 9.

Due to the forecasted residual balance in this account, API is requesting that the OEB approve, on an interim basis, an extension of the sunset date for this rate rider as detailed in Section 9.11.3. The rate rider would otherwise expire on June 30, 2019, resulting in temporary bill decreases for six months, and the disposition of the residual balance would require either a larger rate rider, or a further extended disposition period, beginning on January 1, 2020.

1.3.9 BILL IMPACTS

For the purpose of the notice of application, the 2020 distribution rates proposed by API will result in increases to the distribution portion of the bill (Subtotal A of the Bill Impact Model) for residential customers using 750 kWh per month (RPP-TOU) of $2.33 and for small commercial customers using 2000 kWh per month (RPP-TOU) of $7.44.

Table 1 below shows a summary of all components of the bill impacts for a range of consumption scenarios across all customer classes.

Further explanation of bill impacts is found in Section 8.3.13 of Exhibit 8.

Table 1 – Bill Impacts

Customer Classification and Billing Type	Energy kWh	Demand kW	Sub-Total						Total	
			A		B		C		Total Bill	
			$	%	$	%	$	%	$	%
Residential - R1(i) (RPP)	269	-	$ 1.03	2.8%	$ 0.86	2.2%	$ 1.42	3.3%	$ 1.48	2.1%
Residential - R1(i) (RPP)	750	-	$ 2.33	6.6%	$ 1.86	4.6%	$ 3.40	6.7%	$ 3.55	2.9%
Residential - R1(i) (Retailer)	750	-	$ 2.33	6.6%	-$ 31.55	-85.5%	-$ 30.01	-63.5%	-$ 31.53	-22.5%
Residential - R1(ii) (RPP)	2,000	-	$ 7.44	7.9%	$ 6.19	5.8%	$ 10.30	7.6%	$ 10.74	3.3%
Residential - R1(ii) (Retailer)	2,000	-	$ 7.44	7.9%	-$ 82.90	-85.5%	-$ 78.79	-63.3%	-$ 82.80	-22.3%
Residential - R2 (non-RPP)	90,000	225	$ 199.56	16.0%	-$ 3,804.46	-870.0%	-$ 3,633.94	-225.3%	-$ 4,208.38	-29.1%
Residential - R2 (Class A)	2,500,000	5,000	$ 4,123.65	30.0%	$ 3,745.65	33.1%	$ 7,534.79	20.1%	$ 5,680.27	1.4%
Seasonal (RPP)	50	-	$ 5.25	8.2%	$ 5.21	8.1%	$ 5.31	8.1%	$ 5.58	7.6%
Seasonal (RPP)	153	-	$ 7.85	9.6%	$ 7.74	9.3%	$ 8.05	9.4%	$ 8.45	8.1%
Seasonal (RPP)	750	-	$ 22.96	12.2%	$ 22.23	11.4%	$ 23.77	11.5%	$ 24.93	8.8%
Seasonal (Retailer)	750	-	$ 22.96	12.2%	-$ 10.81	-5.8%	-$ 9.27	-4.7%	-$ 96.46	-32.3%
Street Lighting (non-RPP)	3,308	9	$ 100.19	8.1%	-$ 54.52	-4.4%	-$ 54.80	-4.3%	-$ 57.66	-3.3%

Subtotal A: represents the distributor's fixed and variable charges plus rate riders associated with Group 2 and other deferral and variance accounts
Subtotal B: represents Subtotal A plus rate riders associated with Group 1 deferral and variance accounts, cost of line losses (for most cases), and the SME charge
Subtotal C: represents Subtotal B plus retail transmission service rates
Total Bill impacts includes Subtotal C plus administrative and regulatory charges, commodity rates, and taxes

1.3.10 STATEMENT AS TO THE FORM OF HEARING REQUESTED

This Application is supported by written evidence, which may be amended from time to time, prior to the Board's final decision on the Application.

API requests that pursuant to Section 34.01 of the Board's Rules of Practice and Procedure, this proceeding be conducted by way of written hearing in an effort to minimize costs but understands that if certain issues remain unsettled, the utility may be required to participate in an oral hearing.

1.3.11 DEVIATIONS FROM FILING REQUIREMENTS OR CHANGES TO MODELS

Except where specifically identified in the Application or noted below, API followed the Filing Requirements and used the OEB-issued Cost of Service models in order to prepare this application. The Excel version of the completed Cost of Service Checklist is being filed in conjunction with this application.

In any case where a specific section of the Filing Requirements is not applicable to API's circumstances, API has indicated "N/A" and provided an accompanying description in the Cost of Service Checklist.

The following changes to OEB models, use of alternative models, or use of alternative inputs to the models were necessary to address API's circumstances:

- Since OEB cost of service models were not updated for rates effective in 2020 as of the filing date, API used the 2019 version of most models in consultation with OEB Staff;
- On sheet I6.2 of the OEB Cost Allocation Model, bad debt data entered in the 2015-2017 rows is based on API's 2016-2018 bad debt data;
- The selection list in cell E95 of Sheet 11 of the RRWF only allows selection of up to 2016 for the most recently approved revenue-to-cost ratios. API selected 2015, indicating that the ratios were approved as part of API's last cost of service application for 2015 rates. For clarity however, the values entered in this column reflect the ratios that were

approved in API's 2019 IRM application as part of a 2015-2019 rebalancing plan approved by the OEB in 2015;

- Many of the values in the DVA continuity schedule were shifted by a year, as described in Exhibit 9;
- The OEB's Benchmarking Forecast Model was adjusted to reflect a 2020 Test Year instead of 2019 and additional columns were added to forecast performance over the entire period covered by the DSP (2020-2024);
- The OEB Cost Allocation Model and Revenue Requirement Workform were populated on the basis of "Equivalent Rates", which are the rates that would apply in the absence of RRRP funding, as described in detail in Exhibits 7 and 8;
- API used its own Rate Design Model, consistent with the model used by API in historical applications, to accommodate its unique circumstances with respect to RRRP funding, as described in Exhibit 8;
- API used a custom Bill Impact Model and filed separate 2019 and 2020 Tariffs in Excel files because the OEB Tariff Schedule and Bill Impact Model was not updated for 2020 applications prior to the filing date;
- The 2019 tariff includes adjustments resulting from API's the API/DLI MAAD Application; the 2020 version uses the adjusted 2019 tariffs as a starting point and incorporates all changes proposed in this Application;
- As described in Section 1.3.15, API has reported under ASPE since 2011. Cell E40 on the "LDC Info" sheet of the Chapter 2 Appendices model was left blank since the drop down list does not allow API to select 2011;
- The following tabs of the Chapter 2 Appendices model are not applicable to the Application: 2-FA, 2-FB, 2-FC, 2-Q and 2-S;
- Fixed asset continuity schedules and depreciation schedules (Appendices 2-BA and 2-C) were filed as a stand-alone workbook, instead of populating those tabs of the Chapter 2 Appendices model;
- A number of changes were made to the OEB's LRAMVA model, as documented within that model.

API recognizes that 2020 cost of service models will be made available in due course. To the extent that any of these models incorporate material changes from 2019 versions, API will update the models as required.

1.3.12 CHANGES IN METHODOLOGIES

As detailed in Section 2.1.3 of Exhibit 2, in accordance with Board Staff's preference in EB-2014-0055, a shared IT charge reflected in OEB Account 4380 has been reflected in historical actuals, as well as the Bridge Year and Test Year forecasts. This charge replaces the former practice of allocating capital costs to API, which is reflected in the 2015 Board Approved amounts.

API adopted MIFRS accounting effective January 1, 2013. This accounting policy change resulted in the inclusion of vehicle depreciation within the burden rates calculated for operational departments. For the 2015 Board approved revenue requirement, API had classified the offsetting credit as a credit within General and Administrative expenses. Per Board staff direction issued in 2014, the vehicle credit was to be recorded as a reduction in depreciation expenses which is where API recorded the credit in the 2015 and subsequent actuals in the current Application.

API has made changes to its cost allocation process since 2015. The first change relates to allocation of a portion of rate base amounts to the “bulk delivery” category to more accurately reflect the function of its sub-transmission assets. The second change relates to direct allocation of certain costs to specific customer classes following API’s proposed acquisition of the assets and customers of Dubreuil Lumber Inc. (“DLI”). Both of these changes are described in detail in Exhibit 7.

There have been no other changes in methodologies since API’s 2015 cost of service application.

1.3.13 BOARD DIRECTIVE FROM PREVIOUS DECISIONS

At the date of this submission, API is not aware of any Board Directives from any previous Board Decisions and/or Orders that require addressing in this Application.

1.3.14 CONDITIONS OF SERVICE

API's conditions of service were last updated in April of 2019, and are accessible on its website at:
http://www.algomapower.com/Userfiles/File/2019%20API%20Conditions%20of%20Service%2004182019.pdf

API confirms that are no rates or charges listed in the Conditions of Service that are not listed in its Tariff of Rates and Charges.

1.3.15 ACCOUNTING STANDARDS FOR REGULATORY AND FINANCIAL REPORTING

Changes in Tax Status:

API is a corporation incorporated pursuant to the Ontario Business Corporations Act and has not had a change in tax status since its last Cost of Service application.

Existing/Proposed Accounting Orders

EB-2013-0368 PENSION AND OTHER POST-EMPLOYMENT BENEFITS DEFERRAL AND VARIANCE ACCOUNTS

On December 12, 2013, API received a Decision and Order from the Board (EB-2013-0368) approving the establishment of specific deferral and variance 1508 accounts related to pension and other post-employment benefits ("P&OPEB") subject to the conditions of the Order. The description of these deferral and variance accounts can be found in Section 9.3.2. API has continued to book journal entries in accordance with the Accounting Order to record the difference between P&OPEB expenses under Section 3461 and Section 3462. API is not seeking recovery of any variances recorded in these accounts within this application.

EB-2015-0040 REPORT OF THE OEB RE: REGULATORY TREATMENT OF PENSION AND OTHER POST-EMPLOYMENT BENEFITS

On September 14, 2017, the OEB issued a report regarding the Regulatory Treatment of P&OPEB Costs. Within the report, the OEB provides for the establishment of the P&OPEB Forecast Accrual versus Actual Cash Payment Differential variance account on a generic basis, effective January 1, 2018. API has been using the appropriate 1522 sub accounts and is requesting disposition of the accumulated carrying charges within Exhibit 9 of this application.

EB-2015-0304 WIRELINE POLE ATTACHMENT CHARGES

On July 20, 2018, the OEB issued a letter outlining accounting guidance in connection with the implementation of the new pole attachment charge. API has been accumulating the excess incremental revenue along with applicable carrying charges in the 1508 sub accounts that have been prescribed by the OEB. API's proposed revenue requirement for 2020 reflects the revenue expected to be earned for pole rental revenues at the new enhanced rates. API will seek disposition of the accumulated variance in this account in a future proceeding, likely in its 2022 IRM application, which would be no less than a year after API has completed accumulating a variance in this account.

EB-2015-0304 ENERGY RETAILER SERVICE CHARGES

On February 14, 2019, the OEB issued a Decision and Order which included accounting guidance regarding energy retailer service charges. Effective May 1, 2019, API will accumulate the difference between the revenue collected from the current electricity distributor Retail Service Charges and the revenue collected with the updated electricity Retail Service Charges along with applicable carrying charges in the 1508 sub accounts that have been prescribed by the OEB. API's proposed revenue requirement for 2020 reflects the revenue expected to be earned for Retail Service Charge revenues at the new enhanced rates. API will seek disposition of the accumulated variance in this account in a future proceeding, likely in its 2022 IRM application, which would be no less than a year after API has completed accumulating a variance in this account.

EB-2017-0153 API INTERIM DISTRIBUTION LICENSE IN TOWNSHIP OF DUBREUILVILLE, AND EB-2018-0271 LEAVE TO SELL DUBREUIL LUMBER INC.'S ELECTRICITY DISTRIBUTION SYSTEM TO API

On April 4, 2017, the OEB issued an Order requiring Dubreuil Lumber Inc. to surrender possession and control of the electricity distribution system in the Township of Dubreuilville to Algoma Power Inc. Within that order, API was directed to record revenues collected from customers within the service area of Dubreuil Lumber Inc., and the costs of operation and maintenance of the system in a deferral account under the Uniform System of Accounts. API has accumulated these costs along with additional capital and one-time costs in OEB 1508 sub accounts. The disposition of these amounts has been requested within EB-2018-0271.

Accounting Standard used in Application

API has reported under the Accounting Standards for Private Enterprises accounting standard since January 1, 2011. Previous to January 1, 2011, API reported in accordance with the Canadian Generally Accepted Accounting Principles accounting standard. API adopted MIFRS and confirms that it made the required changes to its capitalization policies and depreciation rates in 2013. These changes were reflected and approved within API's last Cost of Service proceeding, EB-2014-0055, and values presented within this application have also been reported using this methodology.

Compliance with the Uniform System of Accounts

With one exception, API has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application. Due to the non-significant dollar value associated with Retail Service Charges, API has not followed the Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. Further explanation can be found in Exhibit 9.

API has adopted the various account changes prescribed by the Board in relation to the USoA (Article 210 – Chart of Accounts and Account 220 – Account Descriptions).

As of the application submission date, API continues to review the OEB's letter dated February 21, 2019 regarding Accounting Guidance related to Accounts 1588 RSVA Power, and 1589 RSVA Global Adjustment. Where appropriate, changes to API's process with respect to those accounts will be made so as to comply with this guidance.

The useful lives proposed by API in this Application are consistent with the typical useful lives in the Kinectrics Report commissioned by the OEB dated July 8, 2010. API has not changed its accounting methodology since its last rebase in 2015.

Monthly Billing

Consistent with all historical years presented within this application, API confirms that it continues to bill customers on a monthly basis.

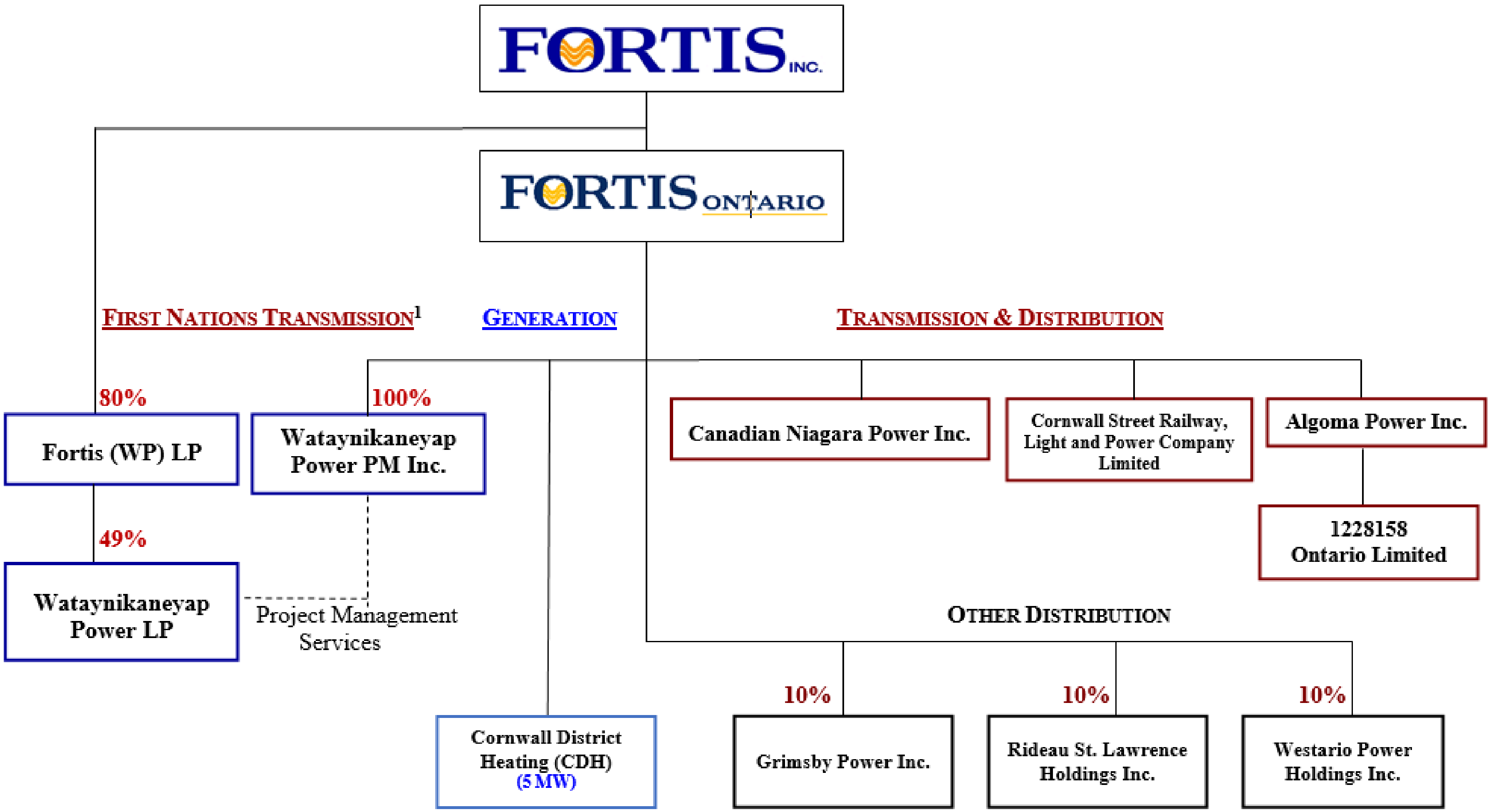
1.3.16 ACCOUNTING TREATMENT OF NON-UTILITY RELATED BUSINESS

API is engaged in the delivery of the Independent Electricity System Operator's ("IESO") (previously the Ontario Power Authority) conservation and demand management programs. The accounting for these activities is segregated from API's rate regulated activities in accordance with the Board's Accounting Procedures Handbook for Electricity Distributors.

1.3.17 CORPORATE ORGANIZATION

Corporate Entities Relationship Chart and Utility Organizational Structure

The chart on the following page illustrates the corporate entities relationship of API, its shareholder and its affiliates carrying on business in Ontario:



[1] FortisOntario has a 100% interest in Fortis (WP) GP Inc., the General Partner of Fortis (WP) LP.

Organization of Entities

API is a wholly-owned subsidiary of FortisOntario Inc. (“FortisOntario”), which is headquartered in Fort Erie, Ontario. FortisOntario owns and operates generation, transmission and distribution businesses in the province of Ontario. Founded in 1892, FortisOntario began generating electricity in 1905 from its Rankine Generating Station located on the Canadian side of the Niagara River and subsequently began distributing electricity to the Town of Fort Erie in 1907. The Rankine Generating Station ceased operations in 2005 and was transferred to the Niagara Parks Commission in 2009. Accordingly, FortisOntario’s operations in Ontario are primarily transmission and distribution.

FortisOntario is the Ontario-based subsidiary of Fortis Inc. ("Fortis"), which is the largest investor-owned gas and electric distribution utility in Canada. With 2018 total assets of approximately $53 billion and annual revenues of approximately $8.4 billion, Fortis serves approximately 3.3 million gas and electricity consumers across Canada, the United States and the Caribbean. Fortis is a publicly traded company listed on the TSX and the NYSE.

FortisOntario also owns Canadian Niagara Power Inc. (“CNPI”) (ED-2002-0572 and ET-2002-0073), and Cornwall Street Railway Light and Power Company Limited (“Cornwall Electric”) (ED-2004-0405). CNPI is a single corporate entity which has two internal business units: a transmission business and a distribution business. CNPI’s distribution business serves approximately 29,000 customers in the Town of Fort Erie, the City of Port Colborne, and the Town of Gananoque. CNPI’s transmission business owns transmission assets in the Niagara Region. Cornwall Electric serves approximately 25,000 customers in and around the City of Cornwall.

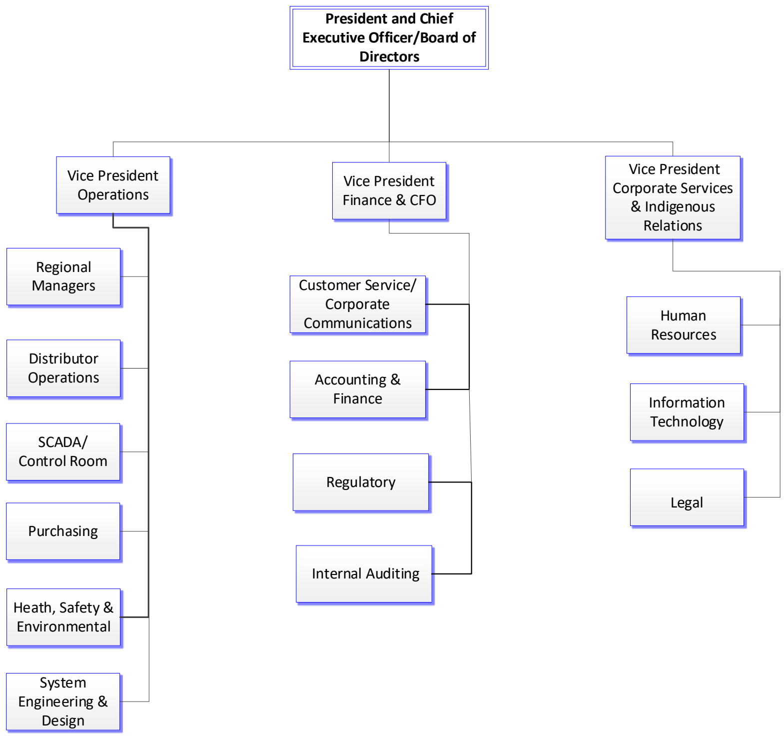
FortisOntario is a licenced generator (EG-2003-0107), which owns a 5 MW natural gas cogeneration district heating plant located in Cornwall, Ontario. The Cornwall district heating facility is an embedded generator selling district heating to local customers and electricity directly to Cornwall Electric, which is isolated from the IESO-controlled grid.

FortisOntario holds a ten percent (10%) interest in Westario Power Inc. (ED-2002-0515), a 23,000 customer electricity distributor located in mid-western Ontario, a ten percent (10%) interest in Rideau St. Lawrence Holdings Inc. (ED-2003-0003), a 6,000 customer electricity distributor located in southeastern Ontario, and a ten percent (10%) interest in Grimsby Power Inc. (ED-2002-0554), a 11,000 customer electricity distributor located in the Niagara region. Accordingly, Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc. are not affiliates of API as defined by the *Ontario Energy Board Act, 1998*.

Fortis is also a partner in the First Nations-led Wataynikaneyap Power LP transmission partnership (ET-2015-0264) with 24 First Nations partners.

Utility Organizational Structure

The chart on the following page illustrates the utility's organization structure showing main units and senior management positions with the utility. The CEO and Vice Presidents are also appointed as officers of API (i.e. each member of FortisOntario Executive holds the same position with respect to API).



Shared Corporate Services

Shared corporate services being provided to API include the following:

- Executive Services
- Finance
- Information Technology
- Human Resources
- Health, Safety and Environment
- Regulatory
- Engineering
- Legal

It is anticipated that shared corporate services will continue to be provided to API from affiliates in the future.

Corporate Governance

The objective of effective and responsive corporate governance is achieved by continually reviewing structures, policies, and programs against best practices in utility governance.

One of those structures is the API board of directors. API has three directors who serve on its board of directors. Two of the API directors are also officers of API, CNPI, FortisOntario and Cornwall Electric and one director is independent. While there is no specific policy on the number of independent directors, the board follows a guideline of one third of the board members being independent. API's Articles of Incorporation indicates a minimum of 1 and a maximum of 10 directors.

Board of Directors' Mandate

FortisOntario ensures a level of consistency in the governance function of its Ontario operating subsidiaries. The API board does not have a written mandate. The role of the API board is to supervise the management of the business and affairs of API. In doing so, the directors are required to act honestly and in good faith with a view to the best interests of the corporation. Both in legal and practical terms, this means that the board must have regard to the interests of varying API stakeholders, including shareholders, customers and creditors, as well as exercising independent judgement in determining the best interests of the corporation. In a number of respects, FortisOntario provides key services relating to API's operations and defines the strategic direction for API. This ensures that the API board has the resources it requires to ensure that its strategy, risk management and internal controls and processes are consistent.

In conjunction with these responsibilities, the directors of API understand that they have a fiduciary duty to API.

Board Meetings

API's board is scheduled to meet in Q2 and Q4 of 2019 and 2020.

Qualifications and Continuing Education

API's non-independent directors are also executive officers and/or directors of API, its affiliates and its parent company, FortisOntario. This ongoing active engagement on the boards and executive management of the parent and affiliates of API ensures that these directors maintain the knowledge, skill, continuing education and experience necessary to meet their obligations as directors of API. The non-independent directors and officers of API are also involved in the selection of the independent board member of API to ensure their independence, and level of skill and knowledge necessary to meet their obligations as directors. In addition, continuing education sessions are included in API board meetings to broaden the skill and knowledge of all directors. API's current independent director is a lawyer with expertise in corporate governance.

Code of Conduct and Ethics Policy

The board of directors of API has approved a written Code of Conduct for the directors, officers and employees, (the "Code" or "Code of Conduct"). This Code of Conduct is consistent between FortisOntario and all of its operating subsidiaries. The monitoring of ethical business conduct of API's employees, officers and directors is a governance function exercised primarily by API's parent, FortisOntario.

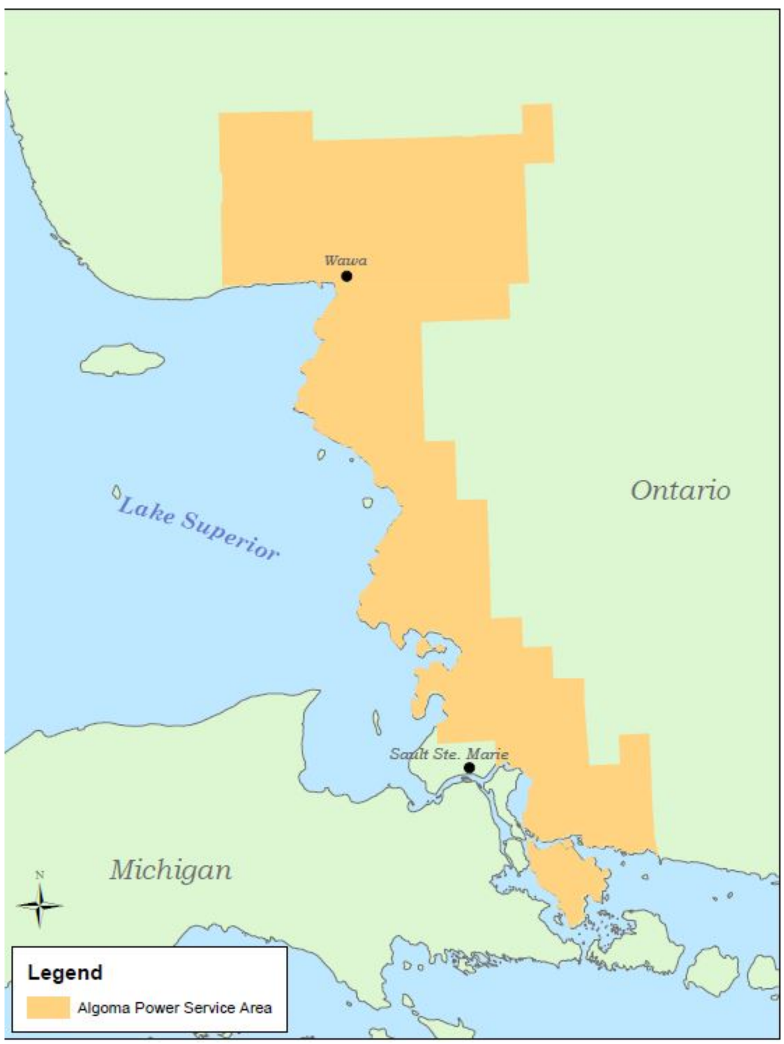
The API board monitors compliance with its Code by updates from executive management of API (who act in a dual capacity as executive management of FortisOntario) on Code of Conduct violations. The board of API has also approved a Policy on Reporting Allegations of Suspected Improper Conduct and Wrongdoing and an Anti-Corruption Policy to satisfy itself regarding compliance with the Code. In other words, allegations of Code of Conduct violations would be brought to the attention of the parent company, FortisOntario, and managed in accordance with its policies. Any reporting of a Code of Conduct violation involving API would be brought to the attention of the API board by management of API and/or the management or board of FortisOntario.

1.4 DISTRIBUTION SYSTEM OVERVIEW

1.4.1 SERVICE AREA OVERVIEW

API's service area extends approximately 93 km east and 255 km north of the City of Sault Ste. Marie, covering approximately 14,200 km^2, which includes 7 First Nation Reserves, 14 organized townships, and a large number of unorganized townships.

The map below shows the extent of API's service area. Additional maps showing the communities served by API and township boundaries are included at Appendix 1E. A more detailed overview of API and its ownership structure, service area, unique aspects and key challenges can be found in Section 3 of the Business Plan, which is included as Appendix 1B.



1.4.2 HOST/EMBEDDED DISTRIBUTOR AND NEIGHBOURING UTILITIES

API is connected directly to the transmission system of Hydro One Sault Ste. Marie Inc. (ET-2007-0649) via eight different delivery points. As such, API is not an embedded distributor.

Dubreuil Lumber Inc. ("DLI") is a licenced distributor (ED-2018-0285) that has historically been supplied by API's distribution system. Since April 4, 2017, the DLI distribution system has been operated by API pursuant to an interim distribution licence (ED-2017-0153) that was issued under sections 59(1) and (2) of the Act. API is in the process of acquiring DLI's electricity distribution system, as further described in Section 1.11.1 below. API has historically billed DLI as a Residential – R2 rate class customer. For the purpose of the 2020 Test Year load forecast, pending the Board's determination on certain preliminary issues in this proceeding, API has assumed that existing DLI customers will become API customers and has therefore reallocated load from the R2 rate class to the R1 and Street Lighting rate classes, and has adjusted customer counts accordingly, as detailed in Exhibit 3. As such, API is no longer a host distributor.

The following electricity distributors are adjacent to API's service area:

- PUC Distribution Inc. (ED-2002-0546)
- Hydro One Networks Inc. (ED-2003-0043)

1.4.3 TRANSMISSION OR HIGH VOLTAGE ASSETS

API does not have any transmission or high voltage assets (> 50 kV) deemed by the OEB as distribution assets. API does not have any such assets that it is asking the OEB to deem as distribution assets in the present application.

1.5 APPLICATION SUMMARY

This section is devoted to defining each element of API's 2020 cost-of-service, explaining how each element is determined and explaining the relationship between the various components. The major components covered in this application summary are as follows:

- Revenue Requirement
- Budgeting Assumptions
- Load Forecast Summary
- Rate Base and DSP
- Operation Maintenance and Administration Expense
- Cost of Capital
- Cost Allocation and Rate Design
- Deferral and Variance Account Disposition
- Bill Impacts

Revenue Requirement

The proposed Service Revenue Requirement for the 2020 test year of $25,937,065 reflects an increase of $2,654,124 or 11.4% relative to 2015 Board Approved. The Base Revenue Requirement on which rates are calculated is $25,885,176, reflecting other revenue offsets of $51,889.

Applying API's 2019 approved rates to its 2020 forecast of load, demand and customer counts produces a forecasted revenue of $23,692,323, resulting in a net revenue deficiency of $2,192,853. API is applying for 2020 rates and RRRP funding to eliminate this deficiency and recover its revenue requirement.

1 **Table 2 – 2015-2020 Revenue Requirement**

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Particular	**Last Board Approved**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
OM&A Expenses	$12,304,881	$11,815,559	$11,803,904	$12,131,721	$12,134,596	$12,924,455	$13,677,187
Depreciation Expense	$3,899,209	$3,136,802	$3,326,205	$3,438,399	$3,600,160	$3,796,858	$4,043,341
Property Taxes	$107,800	$115,453	$112,102	$113,924	$115,938	$119,000	$118,600
Total Distribution Expenses	$16,311,890	$15,067,814	$15,242,211	$15,684,044	$15,850,694	$16,840,313	$17,839,128
Regulated Return On Capital	$6,561,398	$6,417,885	$6,830,093	$7,088,901	$7,299,850	$7,679,811	$7,763,963
Grossed up PILs	$409,653	$581,009	$440,903	$475,362	$560,067	$196,748	$333,974
Service Revenue Requirement	$23,282,941	$22,066,708	$22,513,207	$23,248,307	$23,710,612	$24,716,872	$25,937,065
Less: Revenue Offsets	-$466,758	$68,748	$144,840	$434,381	$164,157	$189,388	-$51,889
Base Revenue Requirement	$22,816,183	$22,135,456	$22,658,047	$23,682,688	$23,874,769	$24,906,260	$25,885,176

The primary drivers of the change in revenue requirement are an increase in rate base, an increase in OM&A and property tax expenses, and a decrease in other revenue offsets. An increase in depreciation expense and a decrease in income taxes contribute to a lesser degree. Each of these contributing factors is summarized in Section 6.3.2 of Exhibit 6. Table 3 below compares each component of API's proposed 2020 revenue requirement to 2015 Board Approved amounts.

Table 3 – Change in Revenue Requirement since Last Board-Approved

	MIFRS	MIFRS	Difference	
	2015	2020	Absolute	%
Long Term Debt	5.15%	4.95%	-0.20%	-4%
Short Term Debt	2.16%	2.82%	0.66%	31%
Return on Equity	9.30%	8.98%	-0.32%	-3%
Weighted Debt Rate	4.95%	4.81%	-0.14%	-3%
Regulated Rate of Return on Rate Base	**6.69%**	**6.48%**	**-0.21%**	**-3%**
Controlable Expenses	$12,412,681	$13,795,787	$1,383,106	11%
Power Supply Expense	$23,068,924	$21,076,879	-$1,992,045	-9%
Working Capital Base	**$35,481,605**	**$34,872,667**	**-$608,938**	**-2%**
Working Capital Allowance Rate	10.00%	7.50%	-2.50%	-25%
Working Capital Allowance ("WCA")	**$3,548,161**	**$2,615,450**	**-$932,710**	**-26%**
Net Fixed Assets Opening Test Year	$91,900,401	$115,263,940	$23,363,539	25%
Net Fixed Assets Closing Test Year	$97,146,940	$119,252,035	$22,105,095	23%
Avgerage Net Fixed Assets	$94,523,671	$117,257,988	$22,734,317	24%
Working Capital Allowance	$3,548,161	$2,615,450	-$932,710	-26%
Rate Base	**$98,071,831**	**$119,873,438**	**$21,801,607**	**22%**
Deemed Interest Expense	$2,913,126	$3,458,109	$544,983	19%
Deemed Return on Equity	$3,648,272	$4,305,854	$657,582	18%
Regulated Return on Rate Base	**$6,561,398**	**$7,763,963**	**$1,202,565**	**18%**
Regulated Return on Rate Base	$6,561,398	$7,763,963	$1,202,565	18%
OM&A + Property Taxes	$12,412,681	$13,795,787	$1,383,106	11%
Depreciation Expense	$3,899,209	$4,043,341	$144,132	4%
Income Taxes	$409,653	$333,974	-$75,679	-18%
Revenue Offset	-$466,758	-$51,889	$414,868	-89%
Base Revenue Requirement	**$22,816,183**	**$25,885,176**	**$3,068,993**	**13%**

Budgeting and Accounting Assumptions

In preparing its cost forecasts for the Application, API has assumed an inflation rate of 1.5%, consistent with the rate used for 2019 IRM applications. API has not factored any additional growth into its forecasts since load forecasts and customer counts remain relatively flat and in line with historical weather-normalized values.

API adopted MIFRS and confirms that it made the required changes to its capitalization policies and depreciation rates in 2013. These changes were reflected and approved within API's last Cost of Service proceeding, EB-2014-0055, and values presented within this application have also been reported using this methodology. There are therefore no impacts resulting from a change in accounting standard.

Load Forecast Summary

The load forecast for 2020 is based on a methodology that predicts class specific consumption using a multiple regression analysis that relates historical monthly wholesale kWh usage to monthly historical heating degree days and cooling degree days.

In API's case, variation in monthly electricity consumption is influenced by four main factors – weather (e.g. heating and cooling), which is by far the most dominant effect on most systems, the number of days per month and an "Employment" factor.

Weather normalized values are determined by using the regression equation with a "10-year average monthly degree days (2009-2018)". The 10-year average is consistent with recent years' weather and has been used in other electricity distribution rate applications accepted by the Board.

Allocation to specific weather sensitive rate classes (R1(i), R1(ii), R2, and Seasonal) is based on historical ratios of actual retail kWh (exclusive of distribution losses) to actual wholesale kWh for each class. Further adjustments are made to the R1(i), R1(ii) and R2 rate classes to account for the acquisition of customers from DLI. For the Street Lighting rate class, which is not weather sensitive, the forecasted 2019 and 2020 load is equal to 2018 actuals, plus a 2020 adjustment for street lights in Dubreuilville.

The resulting 2020 load forecast was further adjusted to take into account CDM impacts.

The 2020 load forecast is summarized on the following pages. Detailed explanations of the load forecast can be found in Exhibit 3.

Table 4 - Load Forecast

Customers or Connections

	Actual					Projected	
Customer Class Name	**Last Board Appr**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
R1(i)	7,531	7,480	7,544	7,596	7,640	7,722	8,116
R1(ii)	965	954	951	961	961	956	997
R2	50	42	42	38	40	39	37
Seasonal	3,138	3,176	3,140	3,108	3,076	3,018	2,960
Street Lighting	1,018	1,023	1,066	1,070	1,067	1,067	1,117
TOTAL	**12,702**	**12,675**	**12,743**	**12,774**	**12,784**	**12,802**	**13,227**

Consumption (kWh)

	Actual					Projected	
Customer Class Name	**Last Board Appr**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
R1(i)	80,045,884	80,876,150	75,910,136	76,321,856	82,834,418	75,387,475	79,805,566
R1(ii)	25,745,817	26,130,351	24,984,442	25,604,789	26,240,994	23,881,888	26,928,875
R2	83,288,188	86,528,984	89,578,886	94,512,143	109,202,680	99,385,190	91,043,719
Seasonal	7,731,414	6,868,390	6,205,026	6,042,453	6,043,635	5,500,303	5,502,049
Street Lighting	804,705	742,696	584,575	582,537	568,784	568,784	595,435
TOTAL	**197,616,008**	**201,146,571**	**197,263,065**	**203,063,777**	**224,890,511**	**204,723,640**	**203,875,644**

CDM Adjusted Consumption (kWh)

	Projected
Customer Class Name	**2020**
R1(i)	78,446,984
R1(ii)	25,484,758
R2	85,867,987
Seasonal	5,439,365
Street Lighting	595,435
TOTAL	**195,834,528**

Consumption (kW)

	Actual					Projected	
Customer Class Name	**Last Board Appr**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
R1(i)	0	0	0	0	0	0	0
R1(ii)	0	0	0	0	0	0	0
R2	198,901	208,261	217,369	210,836	234,800	229,529	210,264
Seasonal	0	0	0	0	0	0	0
Street Lighting	2,380	2,128	1,623	1,619	1,581	1,581	1,655
TOTAL	**201,281**	**210,389**	**218,992**	**212,455**	**236,381**	**231,110**	**211,919**

CDM Adjusted Consumption (kW)

							Projected
Customer Class Name							**2020**
R1(i)							0
R1(ii)							0
R2							196,648
Seasonal							0
Street Lighting							1,655
TOTAL							**198,303**

Primary Metering Adjustment	**0.99**	**0.99**
Customer Class Name	**Current Loss Factor**	**Proposed Loss Factor**
R1(i)	1.0917	1.0829
R1(ii)	1.0917	1.0829
R2	1.0917	1.0829
Seasonal	1.0917	1.0829
Street Lighting	1.0917	1.0829

1

Rate Base and DSP

The proposed Rate Base for the 2020 Test Year of $119,873,438 reflects an increase of $21,801,607, or 22.2% relative to 2015 Board Approved. API's 2015-2020 rate base trend is presented in the following table:

Table 5 – 2015-2020 Rate Base Trend

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Net Fixed Assets:	**2015 Board Approved**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Opening Balance	91,900,401	88,818,527	95,921,772	100,921,057	104,081,529	107,305,666	115,263,940
Ending Balance	97,146,940	95,921,772	100,921,057	104,081,529	107,305,666	115,263,940	119,252,035
Average Balance	94,523,671	92,370,150	98,421,414	102,501,293	105,693,598	111,284,803	117,257,988
Working Capital Allowance	3,548,161	3,556,625	3,666,549	3,455,022	3,415,727	3,503,714	2,615,450
Total Rate Base	**98,071,831**	**95,926,775**	**102,087,963**	**105,956,315**	**109,109,325**	**114,788,517**	**119,873,438**
Year over year variance		-2.19%	6.42%	3.79%	2.98%	5.21%	4.43%

The decrease from 2015 Board Approved to 2015 Actual is primarily due to changes in shared asset allocations from an affiliate, as described in Section 1.3.12. Year over year increases in rate base are primarily driven by capital investments, consistent with API's 2015-2019 DSP. Table 6 below reproduces OEB Appendix 2-AB, which compares planned vs. actual spending over the historical period:

Table 6 – Historical Planned vs. Actual Capital and O&M

CATEGORY	Historical Period **(previous plan & actual)**			Historical Period **(previous plan & actual)**		
	2015			**2016**		
	Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**
	$ '000		%	*$ '000*		%
System Access	1,020	963	-5.6%	1,020	992	-2.8%
System Renewal	4,044	3,809	-5.8%	4,834	4,229	-12.5%
System Service	1,232	3,033	146.2%	538	990	84.0%
General Plant	2,679	3,084	15.1%	2,679	2,369	-11.6%
Capital Contributions	-100	-157	57.1%	-100	27	-127.3%
TOTAL EXPENDITURE	8,875	10,732	20.9%	8,971	8,607	-4.1%
System O&M (exclude Admin)	$6,761	$6,296	-6.9%	$6,897	$6,361	-7.8%

Table 6 (Cont'd)

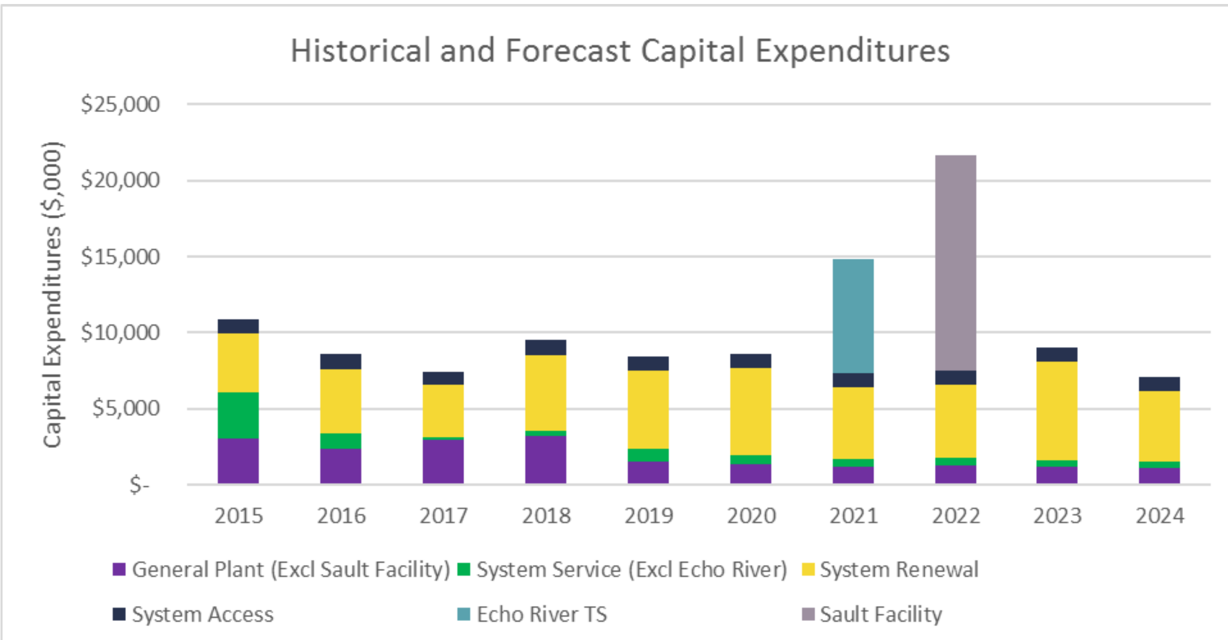
CATEGORY	Historical Period **(previous plan & actual)**			Historical Period **(previous plan & actual)**			Historical Period **(previous plan & actual)**		
	2017			**2018**			**2019**		
	Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**
	$ '000		%	*$ '000*		%	*$ '000*		%
System Access	1,020	883	-13.4%	1,020	960	-5.9%	1,020	913	-10.5%
System Renewal	4,834	3,434	-29.0%	4,834	4,971	2.8%	4,834	5,144	6.4%
System Service	5,088	192	-96.2%	538	339	-37.0%	538	868	61.4%
General Plant	2,529	2,963	17.2%	2,029	3,240	59.7%	1,029	1,500	45.8%
Capital Contributions	-100	- 137	36.5%	-100	- 69	-30.7%	-100	-140	40.0%
TOTAL EXPENDITURE	13,371	7,336	-45.1%	8,321	9,441	13.5%	7,321	8,285	13.2%
System O&M (exclude Admin)	$7,035	$6,715	-4.5%	$7,175	$6,712	-6.5%	$7,319	$7,016	-4.1%

In developing its 2020-2024 DSP, API identified six strategic customer focused objectives that drive capital and O&M plans and related investments over the forecast period:

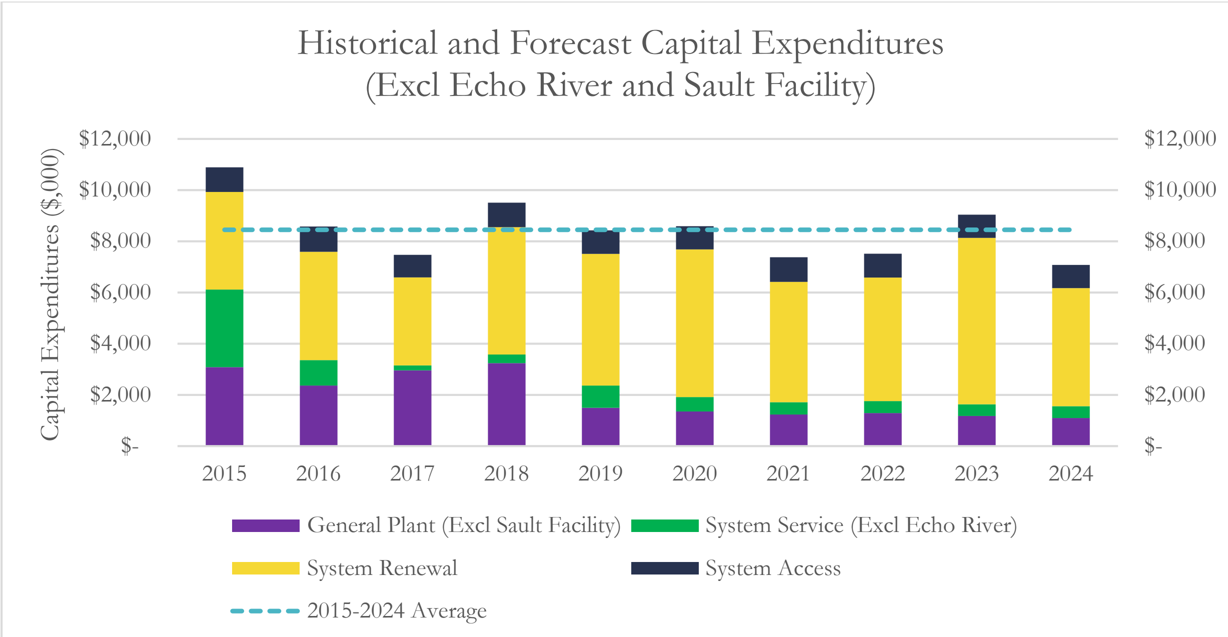
- Sustaining End of Life Asset Replacement
- Sustaining Vegetation Management
- Worker and Public Safety and Environmental Protection
- Reliability Improvement – Focus on Reducing Outage Duration
- Facilities Improvements to Support Productivity and Efficiency
- Flexible Approach to Emerging Technology and Public Policy

API's 2020 Business Plan, included as Appendix 1B describes how the strategic objectives listed above are consistent with its core values and principles, the objectives of the OEB's Renewed Regulatory Framework, as well as the identified preferences of API's customers.

API's capital planning process strives for relatively consistent year to year spending in its sustaining end of life asset replacement programs as well as other programs of a recurring nature. This approach allows API to optimize the use of internal resources and ensures asset replacement on a pace that is consistent with the expected useful life of each type of asset. Larger one-time projects such as substation rebuilds and facility rebuilds are also paced to keep spending consistent, to the extent possible. Over the period covered by the 2020-2024 DSP, investments are required in the Echo River TS and the Sault Facility, resulting in large one-time variances from average levels of capital spending in both 2021 and 2022, as shown in the following chart:



The Echo River TS and Sault Facility projects are consistent with the 2020-2024 strategic initiatives identified above and additional justification for each project is provided in Section 4.4 of API's 2020-2024 DSP. API has requested ACM approval of these projects in 2021 and 2022, as summarized in Section 2.5.4 of Exhibit 2, and has requested an alternative approach to ACM cost recovery as described in Section 1.3.5. Excluding these two projects, actual and forecasted capital spending is relatively consistent over the 2015-2024 period as shown in the following chart:



Details on historical capital variances and details on forecasted capital spending are included in Exhibit 2 and the DSP.

API is not requesting any costs for renewable energy connections/expansions, smart grid projects, or regional planning initiatives.

Operations, Maintenance and Administration Expense

The proposed OM&A expenses for the 2020 test year of $13,677,187 reflects an increase of $1,372,306 or 11.2% relative to 2015 Board Approved. The following table summarizes API's OM&A trend from 2015 Board Approved to the 2020 Test Year.

Table 7 – 2015-2020 OM&A Trend

	2015 Board Approved	2015	2016	2017	2018	2019	2020
Operations	$1,642,392	$1,417,407	$1,296,572	$1,451,821	$1,566,232	$1,790,341	$1,782,437
Maintenance	$5,118,954	$4,879,021	$5,064,915	$5,263,562	$5,145,408	$5,225,959	$5,297,810
Billing and Collecting	$1,090,942	$964,836	$875,602	$874,404	$919,935	$970,387	$995,414
Community Relations	$22,102	$24,430	$32,308	$47,552	$141,890	$94,552	$96,558
Administrative and General	$4,430,491	$4,529,865	$4,534,507	$4,494,382	$4,361,131	$4,843,215	$5,504,968
Total	**$12,304,881**	**$11,815,559**	**$11,803,904**	**$12,131,721**	**$12,134,596**	**$12,924,455**	**$13,677,187**
%Change (year over year)		-4.0%	-0.1%	2.8%	0.0%	6.5%	5.8%

Historical year-over-year variances from 2015 actuals to 2018 actuals have ranged from 0-3%, mainly due to inflationary increases with annual variability in outage response costs, right of way maintenance costs, third-party admin and general services as well as temporary vacancies. Cost drivers for the 2019 Bridge Year and the 2020 Test Year include:

- Delayed recovery of certain costs related to the 2017-2019 interim operation of the distribution system owned by Dubreuil Lumber Inc. ("DLI"), as well as certain transaction and integration costs related to the acquisition of the customers and electricity distribution assets of DLI;
- Increases to rental and permit fees paid by API, partly due to increases in the OEB's generic joint use charges, and offset by increases in other revenues;
- Increased IT costs related to addressing the requirements of the OEB's Cybersecurity Framework;
- Increased finance staff to enhance processes and controls over financial and regulatory reporting;

- Lower than typical 2018 costs due to short-term staffing reductions in a number of Administrative areas due to vacancies and effort allocated to a non-distribution project;
- Filling a unionized position that became vacant in 2017 and was redefined in 2018;
- Increases in Sault Ste. Marie building rent following lease renewal/extension; and,
- Inflationary adjustments at 1.5% per year.

Table 9 on the following page presents API's 2015-2020 OM&A cost drivers, consistent with OEB Appendix 2-JB. Further cost driver analysis is provided in Section 4.2.2 of Exhibit 4.

2020 total compensation of $9,579,879 reflects an increase of $435,652 or 4.8% relative to 2015 Board Approved. This increase reflects a compound average growth rate of 0.94% from 2015 Board Approved, or 0.78% from 2015 Actual. Total compensation is summarized in Table 8 below, and analyzed in detail in Section 4.4 of Exhibit 4.

Table 8 – 2015-2020 OM&A Cost Drivers

	2015 Board Approved	2015	2016	2017	2018	2019 Bridge Year	2020 Test Year
Total Salary and Wages	$6,385,940	$6,659,768	$6,606,283	$6,455,559	$6,891,590	$7,231,903	$7,452,169
Total Benefits	$2,758,287	$2,553,105	$2,046,664	$2,246,996	$2,355,431	$2,483,587	$2,127,710
Total Compensation	**$9,144,227**	**$9,212,873**	**$8,652,947**	**$8,702,556**	**$9,247,021**	**$9,715,489**	**$9,579,879**

Table 9 – 2015-2020 OM&A Cost Drivers

OM&A	**Last Rebasing Year (2015 Actuals)**	**2016 Actuals**	**2017 Actuals**	**2018 Actuals**	**2019 Bridge Year**	**2020 Test Year**
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Opening Balance	12,304,881	11,815,559	11,803,904	12,131,721	12,134,596	12,924,455
Vehicle Depreciation Credit	258,000					
Load Dispatching	(66,000)					
AMI Metering Costs	(44,000)	33,000	38,000			
Outages	(148,000)	121,000	147,000	(273,000)		
Right of Way Maintenance Program	(70,000)	116,000	62,000	207,000		
Miscellaneous Customer Accounts Expenses	(89,000)	(52,000)	(13,000)	77,000		
G&A Outside Services Employed	(80,000)	231,000	(122,000)			
Technical Services Supervisor Vacancy		(47,000)	47,000			
Overhead Lines and Feeders Maintenance - Labour		(48,000)	30,000	23,000	22,000	
Regional Manager		(148,000)	110,000	25,000		
Utilityperson Hire			(60,000)	(60,000)	105,000	
Customer Engagement				109,000	(74,000)	
Maintenance on Poles, Towers and Fixtures, and Overhead Conductors and Devices				(44,000)	78,000	
Joint Use Pole Rental Paid					40,000	
Right of Way Land Fees					47,000	
Sault Ste Marie Building Rent						341,000
Regulatory Expenses						155,000
Shared Services Administrative Services From CNPI Distribution			116,000	(214,000)	294,000	71,000
Dubreuilville Interim License Internal Effort			(109,000)	40,000	19,000	50,000
Miscellaneous	(250,322)	(217,655)	81,817	112,875	258,859	135,732
Closing Balance	11,815,559	11,803,904	12,131,721	12,134,596	12,924,455	13,677,187

Cost of Capital

In this application, API seeks to recover a weighted average cost of capital of 6.48% through rates in the 2020 Test Year. API has followed the Report of the Board on Cost of Capital for Ontario's Regulated Utilities, December 11, 2009 in determining the applicable cost of capital.

In calculating the applicable cost of capital, API has used the OEB's deemed capital structure of 56% long-term debt, 4% short-term debt, and 40% equity, in conjunction with the cost of capital parameters in the OEB's letter of November 22, 2018, for the deemed debt rates and allowed return on equity. The following table summarizes API's capital structure, cost of capital, and the associated return on rate base included in its 2020 revenue requirement.

Table 10 - Overview of Capital Structure

Particulars	**Cost Rate**		**2020 Return on Rate Base**	
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$67,129,125	4.95%	$3,322,892
Short-term Debt	4.00%	$4,794,938	2.82%	$135,217
Total Debt	**60.0%**	**$71,924,063**	**4.81%**	**$3,458,109**
Equity				
Common Equity	40.00%	$47,949,375	8.98%	$4,305,854
Preferred Shares				
Total Equity	**40.0%**	**$47,949,375**	**8.98%**	**$4,305,854**
Total	**100.0%**	**$119,873,438**	**6.48%**	**$7,763,963**

API acknowledges that the OEB may adjust the cost of capital parameters applicable to rate changes effective in 2020, and therefore commits to updating its Application to reflect the revised 2020 parameters, if required.

Cost Allocation and Rate Design

API has prepared and is filing a 2020 Cost Allocation Study consistent with its understanding of the Directions and Policies in the Board's Reports of November 28, 2007 Application of Cost Allocation for Electricity Distributors and March 31, 2011 Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) (the "Cost Allocation Reports") and all subsequent updates.

The cost allocation study accepted in API's 2015 cost of service application (EB-2014-0055) found that revenue-to-cost ratios for the Seasonal and Street Lighting classes were below the OEB's policy range. As part of the Settlement Agreement in that application, the OEB approved the following adjustments over the 2015-2019 period:

Table 11 – Approved Revenue to Cost Ratios 2015-2019

	2015	2016	2017	2018	2019
Residential - R1	110.63%	Beneficiary			
Residential - R2	110.74%	Beneficiary			
Seasonal	60.00%	66.00%	72.00%	78.00%	85.00%
Street Lighting	25.04%	10% Total Bill Impact			

During the course of the EB-2014-0055 proceeding API proposed the possibility of a revising the cost allocation study to consider certain unique aspects of API's system configuration, such as its very low customer density and the use of bulk assets. The 2020 cost allocation study allocates a portion of the rate base amount for certain asset types to the "bulk delivery" category within the OEB Cost Allocation Model, to more accurately reflect the functionality of API's sub-transmission (express feeder) network. Further, API has used the direct allocation functionality within the OEB model to address the acquisition of assets and customers of DLI. All of the foregoing adjustments are detailed in Section 7.2.1 of Exhibit 7.

Consistent with past cost of service applications, the 2020 cost allocation study is based on the use "equivalent rates" for the R1 and R2 rate classes. These are the rates which would apply in the absence of RRRP funding, as further explained in Exhibits 7 and 8.

Since the 2020 status-quo ratio for the Street Lighting rate class exceeds the upper limit of the OEB's policy range, API proposes to adjust the 2020 ratios as shown in the following table:

Table 12 – Rebalancing Revenue to Cost Ratios

Name of Customer Class	Previously Approved Ratios 2019	Status Quo Ratios 2020	Proposed Ratios 2020	Policy Range
	%	%	%	%
Residential R1	105.07	104.57	104.57	85 - 115
Residential R2	105.06	88.46	89.09	80 - 120
Seasonal	85.00	89.98	89.98	80 - 120
Street Lighting	42.79	136.34	120.00	80 - 120

API's rate design is unique in that its R1 and R2 rate classes benefit from funding provided through RRRP payments to API. The determination of the annual RRRP payment can be summarized as follows:

1. Determination of the amount of API's revenue requirement that is allocated to its RRRP-eligible rate classes;
2. Determination of the forecasted distribution rate revenue from API's RRRP-eligible rate classes, considering the most recently approved distribution rates adjusted by the RRRP Adjustment factor; and
3. Calculation of the annual RRRP amount payable to API as the amount by which the revenue requirement identified in Step 1 exceeds the revenue forecasted in Step 2.

API's proposed 2020 rate design in the context of the RRRP framework is detailed in Section 8.2 of Exhibit 8. API confirms that the proposed approach to 2020 rate design is consistent with the approach approved by the OEB in API's prior cost of service applications, and that the transition towards fully fixed rates for Residential – R1(i) and Seasonal customers is consistent with the OEB's decisions on adjustments during the 2016-2019 IRM years. Since the OEB has already approved longer transition periods for API and total bill impacts do not exceed 10%, no bill impact mitigation is required.

The table below shows APIs existing rates in comparison to the 2020 proposed rates:

Table 13 – Distribution Rate Summary

Rate Class and Charge	**Unit**	**2019 Approved**	**2020 Proposed**
Residential - R1(i)			
Monthly Service Charge	$	42.23	47.17
Distribution Volumetric	$/kWh	0.0172	0.0126
Residential - R1(ii)			
Monthly Service Charge	$	25.64	26.21
Distribution Volumetric	$/kW	0.0361	0.0369
Residential - R2			
Monthly Service Charge	$	659.94	674.59
Distribution Volumetric	$/kW	3.4194	3.4953
Seasonal			
Monthly Service Charge	$	54.75	58.75
Distribution Volumetric	$/kWh	0.1494	0.1703
Street Lighting			
Monthly Service Charge	$	2.05	1.37
Distribution Volumetric	$/kWh	0.3310	0.3279

Deferral and Variance Accounts

API proposes to dispose of a credit of $960,461 related to Group 1 and a credit of $26,045 related to Group 2 Variance/Deferral Accounts. These credit balances include carrying charges up to and including December 31, 2018, as well as interest projected to December 31, 2019.

API also proposes to dispose of a net debit balance of $510,390 recorded in account 1568 being the Lost Revenue Adjustment Mechanism Variance Account, and is requesting an extension of its Seasonal Rate Mitigation Plan rate rider to December 31, 2023 as summarized in Section 1.3.8.

Group 1 and Group 2 DVA balances are proposed to be disposed of over a period of 12 months. The rate rider for account 1568 – LRAMVA Balance is proposed to be recovered over a period of 48 months in consideration of the impact on customer rates.

Based on API's billing process, there is no Global Adjustment ("GA") variance for Class A customers. For Class B customers, OEB Account 1589 captures the difference between GA amounts billed to non-RPP customers and the actual GA amount paid for those customers to the IESO. The rate rider for disposition of OEB Account 1589 is therefore applicable to Class B non-RPP customers only. API applied historical RPP/non-RRP percentages to the 2020 load forecast amounts to arrive at estimated non-RPP kWhs for calculation of the 2020 rate rider. An allowance was also made to allocate a portion of the Account 1589 balance to calculate a separate rate rider for one customer that transitioned from Class B to Class A in 2018.

API is requesting three new standard OEB 1595 sub-accounts for the 2020 rate year. API is not requesting to create any other accounts or discontinue the use of any existing accounts.

Table 14 on the following page summarizes the DVA balances sought for disposition in 2020. Exhibit 9 provides detailed calculation of the resulting rate riders, all of which have been factored into 2020 bill impact calculations.

Table 14 – DVA Balances Sought for Disposition

		Amounts from Sheet 2	Allocator
LV Variance Account	1550	0	kWh
Smart Metering Entity Charge Variance Account	1551	(6,137)	# of Customers
RSVA - Wholesale Market Service Charge	1580	(552,366)	kWh
RSVA - Retail Transmission Network Charge	1584	110,430	kWh
RSVA - Retail Transmission Connection Charge	1586	362,391	kWh
RSVA - Power (excluding Global Adjustment)	1588	(76,314)	kWh
RSVA - Global Adjustment	1589	(662,317)	Non-RPP kWh
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	(47,220)	%
Total of Group 1 Accounts (excluding 1589)		**(209,216)**	
Misc. Deferred Debits	1525	(26,045)	kWh
Total of Group 2 Accounts		**(26,045)**	
LRAM Variance Account ***(Enter dollar amount for each class)***	1568	**340,689**	
(Account 1568 - total amount allocated to classes)		340,690	
Variance		**(1)**	
Variance WMS - Sub-account CBR Class B (separate rate rider if no Class A Customers)	**1580**	**(9,437)**	**kWh**
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**425,601**	
Total of Account 1580 and 1588 (not allocated to WMPs)		**(628,680)**	
Balance of Account 1589 Allocated to Non-WMPs		**(662,317)**	
Group 2 Accounts (including 1592, 1532)		**(26,045)**	
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**	
Account 1589 reference calculation by customer and consumption			
Account 1589 / Number of Customers	($61.24)		
1589/total kwh	($0.0038)		

Bill Impacts

A summary of the bill impacts by class is presented in Table 15 below. Detailed explanations of the bill impacts are presented in Section 8.3.13 of Exhibit 8. Neither a rate plan nor a mitigation plan are required as all of API's bill impacts fall below the 10% threshold.

Table 15 – Bill Impact Summary

Customer Classification and Billing Type	Energy kWh	Demand kW	Sub-Total						Total	
			A		B		C		Total Bill	
			$	%	$	%	$	%	$	%
Residential - R1(i) (RPP)	269	-	$ 1.03	2.8%	$ 0.86	2.2%	$ 1.42	3.3%	$ 1.48	2.1%
Residential - R1(i) (RPP)	750	-	$ 2.33	6.6%	$ 1.86	4.6%	$ 3.40	6.7%	$ 3.55	2.9%
Residential - R1(i) (Retailer)	750	-	$ 2.33	6.6%	-$ 31.55	-85.5%	-$ 30.01	-63.5%	-$ 31.53	-22.5%
Residential - R1(ii) (RPP)	2,000	-	$ 7.44	7.9%	$ 6.19	5.8%	$ 10.30	7.6%	$ 10.74	3.3%
Residential - R1(ii) (Retailer)	2,000	-	$ 7.44	7.9%	-$ 82.90	-85.5%	-$ 78.79	-63.3%	-$ 82.80	-22.3%
Residential - R2 (non-RPP)	90,000	225	$ 199.56	16.0%	-$ 3,804.46	-870.0%	-$ 3,633.94	-225.3%	-$ 4,208.38	-29.1%
Residential - R2 (Class A)	2,500,000	5,000	$4,123.65	30.0%	$ 3,745.65	33.1%	$ 7,534.79	20.1%	$ 5,680.27	1.4%
Seasonal (RPP)	50	-	$ 5.25	8.2%	$ 5.21	8.1%	$ 5.31	8.1%	$ 5.58	7.6%
Seasonal (RPP)	153	-	$ 7.85	9.6%	$ 7.74	9.3%	$ 8.05	9.4%	$ 8.45	8.1%
Seasonal (RPP)	750	-	$ 22.96	12.2%	$ 22.23	11.4%	$ 23.77	11.5%	$ 24.93	8.8%
Seasonal (Retailer)	750	-	$ 22.96	12.2%	-$ 10.81	-5.8%	-$ 9.27	-4.7%	-$ 96.46	-32.3%
Street Lighting (non-RPP)	3,308	9	$ 100.19	8.1%	-$ 54.52	-4.4%	-$ 49.48	-3.9%	-$ 52.07	-3.0%

The primary driver of the large total bill decreases for the non-RPP rate classes is a relatively high credit rate rider related to disposition of Global Adjustment variances. This credit is not reflected in the higher consumption R2 scenario since the rate rider does not apply to Class A customers.

For the Residential – R1 and Residential – R2 rate classes, the Sub-Total A bill impacts presented above are affected by the December 31, 2019 expiry of a credit rate rider. Further comparison of bill impacts resulting from changes to base rates in isolation of changes to rate riders is provided in Section 8.3.13.

1.6 MATERIALITY THRESHOLD

In accordance with the Minimum Filing Requirements and given that API's revenue requirement falls within the $10 million to $200 million range, the following materiality threshold has been calculated.

Table 16 – Materiality Calculation

Base Revenue Requirement	**Percentage**	**Calculated Threshold**
$25,885,176	0.5%	**$129,426**

Based on the above, API has used $125,000 as a materiality threshold throughout this Application.

1.7 CUSTOMER ENGAGEMENT

1.7.1 OVERVIEW OF CUSTOMER ENGAGEMENT

Customers remain passionate about the notion of efficient and safe delivery of electricity at low costs. API's strives to continue to provide services that are valued by its customers, in a safe and cost-effective manner. This requires understanding customers' current and future needs. It also requires a culture of embracing continuous improvements in the services API provides, especially the customer experience. Accordingly, API has implemented a comprehensive customer engagement program, which has evolved in accordance with the expectations of the OEB's Renewed Regulatory Framework for Electricity Distributors.

API's goal is to demonstrate a focus on long term value to customers and in turn raise confidence through both education and solicitation of customer feedback. This will lead to the successful implementation of projects that customers consider meaningful.

Significant work has gone into customer engagement activities using various methods and communication channels, which are necessary given the unique geography of API's 14,200 square kilometre service territory and associated 1,850 kilometers of line. Customers, stakeholders and third parties alike have unique requirements and API recognizes that a "one size fits all" approach to engagement is not effective. The following subsections provide detail of API's customer engagement activities across six categories: Customer Satisfaction Surveys, Community Outreach/Stakeholder Sessions, Forestry Outreach, Conservation and Demand Management, Taking AIM Customer Engagement program and Other Supporting Engagement Activities. The complete list of customer engagement activities has been populated in the OEB's Appendix 2-AC, which is included as Appendix 1F to this Exhibit.

Customer Satisfaction Surveys

API has engaged UtilityPULSE to conduct independent telephone-based customer satisfaction surveys since 2015. The survey asks questions of both residential and general service customers on a wide range of topics, including: (a) power quality and reliability; (b) price; (c) billing and payment; (d) communications; and (e) the customer service experience. UtilityPULSE typically conducts the survey in the fall of a given year, with final results available in December. The results are compiled into a final report outlining the overall level of customer satisfaction within API's service area, as well as benchmarking the results against other Provincial and National participants. These results are then used to support internal discussions surrounding what is currently being done well, and what needs improvement. Highlights of the 2015-2018 survey results are included in the "Taking Aim Report", which is provided as Appendix B to API's Business Plan. The following table provide a summary of overall satisfaction results:

Table 17 – Customer Survey Satisfaction Results – 2015-2018

Customer Satisfaction Surveys (Telephone Based)

	2018			2017			2016			2015		
	API	National	Ontario	API	National	Ontario	API	National	Ontario	API	National	Ontario
Overall Satisfaction (%)	93	91	91	88	90	95	79	86	81	92	89	88
Customer Experience Performance Rating (%)	85	84	83	85	83	81	81	81	77	83	83	82

Overall customer satisfaction has generally increased during the 2015-2018 period. The survey provides direct feedback and assists API with identifying opportunities for improvement. Overall satisfaction denotes a consolidated opinion of services provided to the customers. Customer experience performance rating ("CEPr) is a combination of two key attributes: professional customer care and quality of services. This metric answers basics questions such as "does the organization effectively meet your needs?" and "does the organization provide high- quality services". Given 2017 and 2018 scores of 85%, this provides an indication that API is actively listening to customer needs and providing service levels that meet their expectations.

Community Outreach/Stakeholder Sessions

This form of engagement is very important to API's understanding of customer needs through face to face interaction. One on one meetings through the "Your Kilowatt Hour"[8] program allow dialogue with all forms of residential customers and give them an opportunity to provide feedback through this Q&A session.

Annually, API's annual stakeholder session includes topics such as current customer service initiatives, public safety, and conservation demand management updates, incentives, and operations maintenance and capital projects. 17 municipal councils, planning boards and First Nation councils within its service territory are contacted to schedule attendance at one of their regularly scheduled council or planning board meetings. Each presentation provides the councils with updates and encourages dialogue on a number of levels. The operational topics discussed are tailored to each municipality. Councils have commented positively on the value these presentations provide.

API also hosts an Annual Contractor Safety Night with local contractors and invites the local office of the Electrical Safety Authority (ESA). The event provides discussions on Public Safety issues, Customer Service topics regarding interactions between API and the contractor community as well as any changes to API's customer connection process.

Forestry Outreach

The API service territory has a large amount of diverse vegetation. This generates considerable awareness among customers in how the organization manages that vegetation and related habitat stewardship. To that end, seven sessions were held dedicated to forestry and vegetation management. Topics around how right of ways are maintained and other API-specific distribution system elements affected by vegetation were shared with customers. These

[8] The "Your Kilowatt Hour" program was designed to provide pre-scheduled appointments, at accessible community-based locations allowing customer-driven questions and answers on topics related to customer service, billing and CDM.

sessions gave customers an opportunity to ask questions and cite concerns, which API takes into account when planning related activities.

Conservation and Demand Management (“CDM”)

CDM work conducted by API includes a number of initiatives that involve outreach to customers. Reaching out through CDM programs helps customers to better understand their local utility, while they become more knowledgeable about energy conservation. API continues to participate in a number of community events to highlight CDM program offerings.

API’s outreach initiatives showed there were some customers who expressed a need for extra consultation and assistance with various CDM programs. In response to this, utility staff make direct contact with customers to assist them with their concerns and CDM program applications on an individual basis. These outreach efforts provide a communication channel to energy-conscious customers so that the needs and desires of customers are better understood and addressed.

Other Supporting Engagement Activities

API is a relatively small LDC, with approximately 12,000 customers dispersed across a large service area, and as such API has made a considerable effort in promoting a wide range of activities to engage customers. Beyond what has been summarized above, the following is a list of six additional customer engagement activities that support customer outreach and engagement across a variety of platforms.

Social Media (Outage Communication) – Although technology and related social media continues to become a standard means of communication within many Ontario households, API has recognized from direct customer feedback that given the rural nature and somewhat less robust internet connectivity, the request for leading-edge communication techniques has not been considered a priority. API provides Twitter and Facebook updates on planned outages as well as periodic updates during significant storm events. That said, more sophisticated methods such as real-time public facing OMS communication to customer mobile devices has not yet been established. Since API customers also interact with the 24x7 call centre, ongoing dialogue will continue to ensure alignment of communication methods with customer preference is maintained.

Website (General Communication) – The API website (www.algomapower.com) provides a constant flow of updated customer-centric information. Topics such as distribution services, rates, regulatory matters and decisions, marketing campaigns, conservation and demand management programs are made available in this one-stop location.

Technology Based – Similar to the outage communication methods a modest approach has been taken with the development of technology based solutions. Currently, the "MyhydroEye" portal is available to customers that subscribe and provides time-of-use based consumption information. Additionally, billing information is provided again to those customers that subscribe via the e-billing framework. Given the reasonably low uptake on these services, it was suggested that a consolidated and more user-friendly version would be preferred. In response to customer requests, API is reviewing the possibility of an all-inclusive product that can provide an improved user experience.

Front Desk Support – API currently maintains front desk support allowing the customer and the utility to interact on a direct basis. Social interaction is still one of the best ways to be in close contact with the customer. People love being heard and they love giving feedback, which is conveniently done when paying your electrical bill at the front counter of your local utility. With a front desk, information is exchanged regularly with every customer interaction. Data gathered through these interactions can then be used to improve business outcomes. In this sense, front desk staff becomes pivotal to the business and bridges the gap between the customer and other utility staff. API plans on continuing its front desk operations as a form of customer engagement and to ensure expected customer service levels are maintained.

Publications – The majority of API's customers receive a physical bill in the mail, and API takes advantage of this opportunity to communicate additional information via messages on the outside of the envelope, separate inserts, and messages on the bill itself. Many of these messages are coordinated with announcements from the OEB, IESO, and other agencies, and include information about retailers, rate changes, conservation and demand management programs, electrical safety, and references to our website. API also publishes the newsletter (twice per year), which gives information and updates on the industry and/or explains how costs/rates are determined. A copy of API's most recent newsletter is included as Appendix 1G.

Social Services – Financial Assistance Program: Algoma Power Inc. provides support through partnerships with the province's Low-income Energy Assistance Program (LEAP) program. API has utilized Ontario Native Welfare Administrators Association ("ONWAA"), a First Nations organization as its lead organization to administer the LEAP program, as further described in Section 4.7 of Exhibit 4. Programs of this type are designed to help low-income customers who have difficulty making their electricity bill payments and are regularly communicated to API customers via all media channels.

Taking AIM Program

In a climate that is becoming increasingly difficult to develop actions which create value for customers while maintaining cost effectiveness, safety and reliability, getting the most from customer engagement activities is an important priority. In response to this priority API partnered with UtilityPULSE and co-developed a multi-channel approach to gathering wisdom, insights, information and feedback from customers. The results are used to create value for customers and other stakeholders alike.

The Taking AIM program, through a series of seven online surveys, invites customers to learn about their LDC and the industry, tell API about the things which are important to them, and to prioritize or assess various capital projects and programs, operational plans, and other initiatives for consideration in API's development of its DSP and this Application. Findings from the quantitative and qualitative elements of the surveys helped to ensure that the plans developed by API are aligned with its customers' needs, as further detailed in Section 4.2 of API's Business Plan (included as Appendix 1B to this Exhibit). The survey chapters are summarized below:

- Chapter Survey 1 "About your Algoma Power"
- Chapter Survey 2 "How the electricity industry works and Algoma Power's role in it"

- Chapter Survey 3 "Help Algoma Power understand our customer's priorities"
- Chapter Survey 4 "Getting customer insights about billing and outages"
- Chapter Survey 5 "Help us prioritize capital investments in the electricity network"
- Chapter Survey 6 "Gathering insights about customer care operations"
- Chapter Survey 7 "Help us determine which capital investments and operational changes you can support"

The Taking Aim Report provides detail of survey responses across all chapters and summarizes actionable outcomes that API developed in collaboration with UtilityPULSE. The complete report is included as Appendix B to API's Business Plan.

1.7.2 IMPACT OF CUSTOMER ENGAGEMENT ON THE APPLICATION

Section 4 of API's Business Plan describes how API continues to improve in understanding the needs and expectations of its customers, and how API's core values, the needs of its customers, and the OEB's RRF outcomes are integrated and prioritized in its planning activities.

The results of the Taking Aim survey described in the previous section indicated that the top customer priority was to keep costs low. While this results did not come as a surprise to API, the survey was designed in a manner to rank the importance of other customer priorities, to assess customer support for ongoing programs of a mandatory or sustaining nature, and to assess customer support for other specific projects and programs. Table 18 below summarizes how API balanced overall customer feedback with the objective of controlling costs in determining some of the major capital and O&M programs and spending amounts included in the Application.

Table 18 – Impact of Customer Engagement

Project/Program/Activity	**Customer Feedback**	**Impact on the Application (Including Cost Control)**
Vegetation Management	54% of survey respondents supported API continuing with its current 6-8 year cycle, while an additional 29% supported a 4-6 year cycle, despite increased costs	API's plan for the forecast period continues with its current 6-8 year cycle; API has also taken steps to mitigate the impact of Ontario-wide increases market costs for contracted vegetation management, and has kept its 2020 vegetation management budget in line with historical levels, as described in Section 2.3 of the Business Plan
System Access Spending	Survey respondents generally understood the non-discretionary nature of these investments, with 95% of customers supporting the investments	The average investment level for the 2020-2024 period is approximately 2% less than the average over the historical period; API has not included any non-discretionary investments in this category

	93% of survey respondents either believed that existing investment levels were adequate, or supported increases to improve reliability; When presented with cost information, 56% of respondents continued to indicate support for inflationary or above-inflationary spending, with an additional 17% indicating they “didn’t know” what level of spending they could support	API has continued its sustaining assets replacement programs, based on target replacement levels and estimated unit costs; Storm-related capital has been decreased, based on trending; Average spending is higher than historical, due to two substation replacements, one of which resulted from the acquisition of DLI assets - API has proposed a direct allocation of costs related to assets in Dubreuilville to ensure that API’s existing customers are not negatively impacted by the acquisition (see Section1.3.7 of this Exhibit)
System Service Spending	93% of survey respondents either believed that existing investment levels were adequate, or supported increases to meet increasing reliability and outage response expectations; When presented with cost information, 52% of respondents continued to indicate support for inflationary or above-inflationary spending, with an additional 17% indicating they “didn’t know” what level of spending they could support; Respondents prioritized reductions in outage duration over reductions in frequency	API has continued programs related to reliability improvement, with a focus on reducing outage duration; Increases in forecasted spending over historical spending primarily relate to deferring the Echo River TS project from 2017 to 2021, as well as underspending on SCADA deployment (see Section 4.3.2.2 of the DSP) – no new programs were added to this category
Investments in Facilities	88-94% of survey respondents rated the safety, security and/or efficiency of API’s facilities as somewhat or very important, and 88% believed that decisions to renovate or build new should	After considering its facilities options with respect to expiry of its existing lease, API proposes to build a new Sault Ste. Marie facility to support efficiency improvements and increased

	consider a balance of all of these factors and overall cost; Esthetics and other factors were viewed as less important	cost certainty over the long term; API is proposing an alternative ACM cost recovery mechanism to reduce the impact of rate riders for the majority of its customers (see Section 1.3.5 of this Exhibit)
Customer Care Operational Improvements	68% of survey respondents indicated a willingness to pay more for automated outage notification; less than half of respondents were willing to pay for any other customer-care improvements	API will work towards further integration of its AMI and OMS system to allow automated notification under the Business Systems program under the General Plant category; No other customer-care projects were included in this Application
General Plant Spending	97% of survey respondents either believed that existing investment levels were adequate, or supported increases for a variety of reasons; When presented with cost information, 60% of respondents continued to indicate support for inflationary or above-inflationary spending, with an additional 15% indicating they “didn’t know” what level of spending they could support;	See above for Facility and Customer Care items within the General Plant category; Excluding the one-time facility project in 2022, spending in this category is reduced as compared to historical spending, resulting from the completion of the ROW Hardening Program;

1.8 LETTERS OF COMMENT

1.8.1 LETTERS OF COMMENT

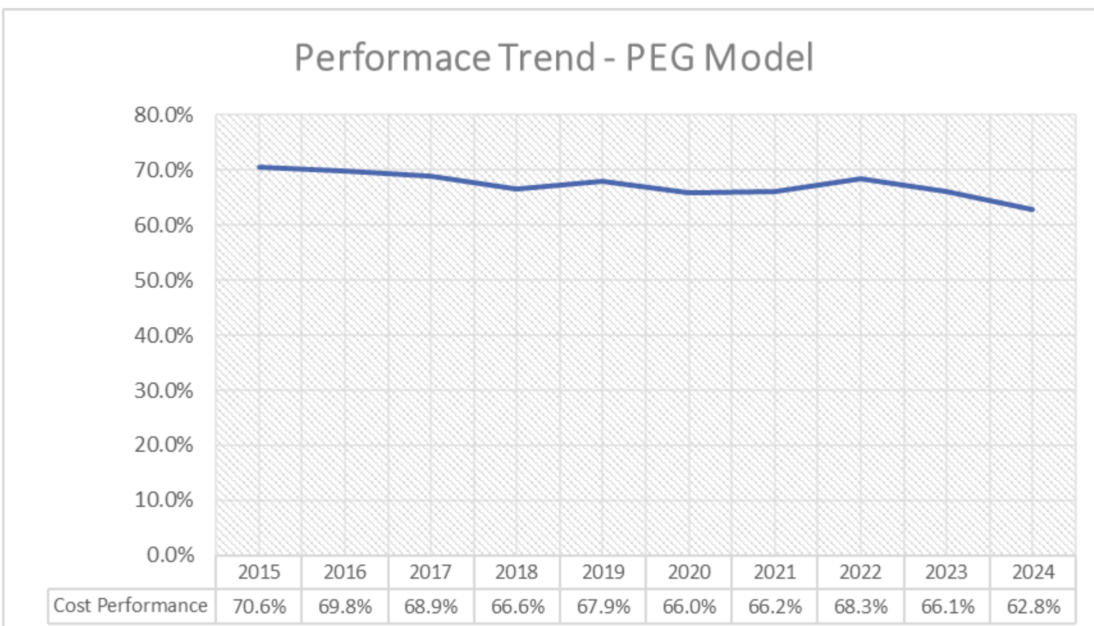
API has not received any letters from its customers related to this application as of the filing date. API is, however, committed to responding to matters raised in letters of comments during the proceeding and will file all customer letters related to the application, along with API's response, as additional evidence.

1.9 SCORECARD ANALYSIS

1.9.1 SCORECARD RESULTS AND ANALYSIS

Section 5 of API's Business Plan outlines API's performance for each of the scorecard measures over the last five years, explains future targets for each measure, and where applicable describes how past performance and/or future targets have affected the proposals in this Application and DSP. The Business Plan is included as Appendix 1B. Additionally, API's 2017 scorecard and MD&A are included as Appendix A to the Business Plan.

API's historical and forecasted efficiency assessment for the 2015-2024 period, using the OEB's Benchmarking Forecast Model, is shown below:



For the reasons summarized in Section 5.1 of the Business Plan, API does not believe that the PEG model cost predictions accurately reflect the cost drivers inherent to API's distribution system and service area. Since API's inputs to the PEG Model remain relatively stable year-over-year however, the trending in cost performance provides useful insight into whether API's cost efficiency is improving over time. The 2015-2024 trend indicates that API's is becoming more efficient over the ten-year period covered by its past and current DSPs. Annual variations in the results can be caused by one-time capital additions, such as the Sault Facility investment in

2022, and as such, API is focused on the overall trend as opposed to slight variability in the year-over-year results.

1.10 FINANCIAL INFORMATION

The OEB's RRFE for electricity distributors includes Financial Performance as one of the performance measurements. The four-financial metrics included in API's Scorecard are liquidity, leverage, deemed return on equity and achieved a return on equity. API's metrics are discussed in Section 5 of the Business Plan. API has replicated the 2015 to 2018 historical year information below for ease of reference.

Table 19 – Financial Ratios from Scorecards

Financial Ratios

	Liquidity: Current Ratio (Current Assets/Current Liabilities)	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	Profitability (Approved ROE)	Regulatory Return on Equity (Achieved ROE)
2015	1.14	1.12	9.30%	11.07%
2016	1.10	1.02	9.30%	9.89%
2017	0.37	1.17	9.30%	8.11%
*2018**	1.04	1.42	9.30%	8.22%
	*Based on numbers drafted for 2018 OEB RRR filings, as of application filing date			

1.10.1 HISTORICAL FINANCIAL STATEMENTS

The following attachments are included as Appendices.

- Appendix 1H Year ended 31 December 2017
- Appendix 1I Year ended 31 December 2018

1.10.2 RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND RESULTS FIELD

As has been prepared in accordance with OEB RRR filing 2.1.13, a reconciliation between the financial results shown in API's RRR filings and API's Audited Financial Statements is presented in Appendix 1J of this Exhibit.

1.10.3 ANNUAL REPORT

The Filing Requirements require an Applicant to file an "Annual Report and Management's Discussion and Analysis for the most recent year of the distributor and of the parent company, **as available and applicable**" [emphasis added].

Neither API, nor its parent company (FortisOntario) publish an Annual Report and MD&A.

API's does prepare a MD&A in respect of the OEB Scorecard, which is included as Appendix A to the Business Plan. FortisOntario is not a licensed distributor and as such does not prepare a similar MD&A.

1.10.4 PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

API has not produced either a prospectus or an information circular to support third-party debt or equity offerings.

1.11 OTHER RELEVANT INFORMATION

1.11.1 DISTRIBUTOR CONSOLIDATION

As outlined in Section 1.3.7, all elements of this Application and DSP reflect a full integration of DLI's distribution system and customers, effective January 1, 2020, and include various proposals put forward in relation to the allocation and recovery of certain historical and forecasted costs related to the Dubreuilville service area, as well as transaction and integration costs. In the event the Board does not accept one or more of the Preliminary Issues on the basis of what API has requested, some or all of the DLI integration related evidence may require updates to reflect the Board's decision or, potentially, a decision by API to not conclude the acquisition.

Given the unique context in which API was required to assume control of the DLI distribution system as an interim operator, many aspects of the OEB's *Handbook to Electricity Distributor and Transmitter Consolidations* either did not apply to the transaction (e.g. the deferred rebasing period), or were applied in a different context (e.g. the "no-harm" test). As such, Section 2.1.10 (Distributor Consolidation) of the Filing Requirements is generally not applicable to this transaction, and API has instead summarized relevant sections of the Application where consideration was given to the acquisition:

- Section 1.3.4 lists approvals requested in relation to the allocation and recovery of DLI-related costs, the details of which are provided in Section 1.3.7;
- Section 1.4.2 confirms that DLI is no longer an embedded distributor to API, and that API is therefore no longer a host distributor;
- Section 1.11.3 includes a copy of the most recent Interim Distribution Licence issued to API in respect of DLI's distribution system;
- Service area maps included as Appendix 1E, highlight the Dubreuilville service area that will become part of API's service area upon closing of the acquisition;

- Section 2.1.3 and 2.5.6 describe the addition of DLI assets to API rate base as a result of capital investments in the DLI distribution system made by API between April 2017 and December 2019;
- Section 3.1.10 describes adjustments made to API's 2020 load forecast to account for metering and billing individual customers in Dubreuilville, instead of bulk metering and billing of a single account for DLI as an embedded distributor;
- Sections 4.6.2 and 4.6.3 describe API's proposal to recover costs recorded in its Transaction and Integration Costs Deferral Account;
- Sections 4.2.2 and 4.3.2 describe the impact of the interim operation of and the proposed acquisition of DLI's distribution system on its historical and forecasted OM&A costs;
- Section 7.2.1 details API's proposal for direct allocation of DLI-related costs, consistent with the approach put forward in the MAAD Application;
- Section 7.2.5 confirms that DLI was historically billed as a Residential – R2 class customer and confirms that since the legacy R2 account will no longer be in effect, any Filing Requirements related to whether or not and LDC uses a distinct Embedded Distributor rate class are not applicable to API;
- Section 9.3.2 confirms that API established Account 1508 sub-accounts to record revenue and costs and confirms that disposition and cost recovery is addressed in the MAAD Application and other areas of the current Application.

Since API has no historical ACM or ICM applications, and DLI was never rate-regulated by the OEB, there is no impact on the consolidation from an ACM/ICM perspective.

1.11.2 APPLICANT'S DISTRIBUTION LICENCE

API operates under OEB Electricity Distribution Licence ED-2009-0072. Additionally, API operates the electricity distribution system owned by Dubreuil Lumber Inc. under Interim Electricity Distribution Licence ED-2017-0153. A copy of these licences are attached as Appendix 1K and Appendix 1L to this Exhibit.

APPENDICES

Appendix 1A	Customer Summary
Appendix 1B	Business Plan
Appendix 1C	List of Approvals
Appendix 1D	Executive Certification
Appendix 1E	Service Area Maps
Appendix 1F	OEB Appendix 2-AC
Appendix 1G	Recent Newsletter
Appendix 1H	2017 Audited Financial Statements
Appendix 1I	2018 Audited Financial Statements
Appendix 1J	Reconciliation – RRR to AFS
Appendix 1K	API Distribution Licence
Appendix 1L	API Interim Licence (DLI)

Appendix 1A

Algoma Power Inc.

2020 Cost of Service

EB-2019-0019

Algoma Power Inc. A FORTIS ONTARIO Company

2020 Cost of Service Application — Customer Summary

ABOUT ALGOMA POWER

Algoma Power provides local distribution service to a rural area that extends approximately 93 km east and 255 km north of the City of Sault Ste. Marie. Algoma Power delivers electricity over 1861 km of distribution lines to approximately 12,000 customers.

Algoma Power's low customer density (customers per km) results in higher than average costs per customer. As a result, rates for residential, commercial and industrial customers are subsidized (see "Rate Setting and Rate Relief").

ABOUT THE APPLICATION

Algoma Power applies to the OEB every year to approve rates for the following year. These applications are on a five-year cycle, with a detailed "Cost of Service" review in Year 1, followed by inflationary adjustments in Years 2-5. Much of the Cost of Service application relates to reviewing Algoma Power's costs and setting its base distribution rates.

Algoma Power does not own transmission lines or electricity generation plants, however it does include these costs on its bills. Costs related to transmission are approved by the Ontario Energy Board (**OEB**) in similar applications by electricity transmitters. Some generation costs are also approved by the OEB, while other costs are a product of either the competitive wholesale market, or long-term power purchase contracts. Algoma Power passes through these costs without any markup or profit margin.

The pass-through transmission rates that Algoma Power charges to its customers are reviewed and approved by the OEB each year. For low-volume customers, the OEB also approves Time of Use and Tiered Electricity Rates (for generation costs) on a province-wide basis. Since Algoma Power's revenue from these pass-through rates is typically different than its actual costs, every rate application includes requests for "rate riders" that true-up any past differences. Depending on the year, these rate riders can either be charges or credits.

CUSTOMER ENGAGEMENT AND PERFORMANCE METRICS

Algoma Power has a broad customer and stakeholder engagement program that includes satisfaction surveys, meetings with First Nation and Municipal councils, forestry outreach programs, electrical contractor and road authority meetings, and participation in community-based events.

Algoma Power also conducted online customer surveys specific to this application, which provided multiple opportunities for customers to identify their need and priorities, and to provide feedback on programs and spending levels.

Algoma Power has considered feedback from all of the above activities with a goal of meeting the needs and preferences of our customers.

The OEB expects utilities to measure their performance across a number of categories: Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance. Every year, the OEB publishes a scorecard that compares Algoma Power's performance against targets and trends over the past five years, which can be accessed on Algoma Power's website. The following OEB website has additional information on utility performance: https://www.oeb.ca/utility-performance-and-monitoring

ALGOMA POWER'S GOALS

Algoma Power operates according to six core values: Respect for People; Safety and the Environment; Financial Success; Customer Service; Productivity; and Community Involvement. Based on a combination of these values, customer preferences and OEB expectations (discussed above), Algoma Power identified six strategic objectives for its Five-Year Plan, which are discussed in Algoma's 2020 Business Plan (Appendix 1B of Exhibit 1 of the application).

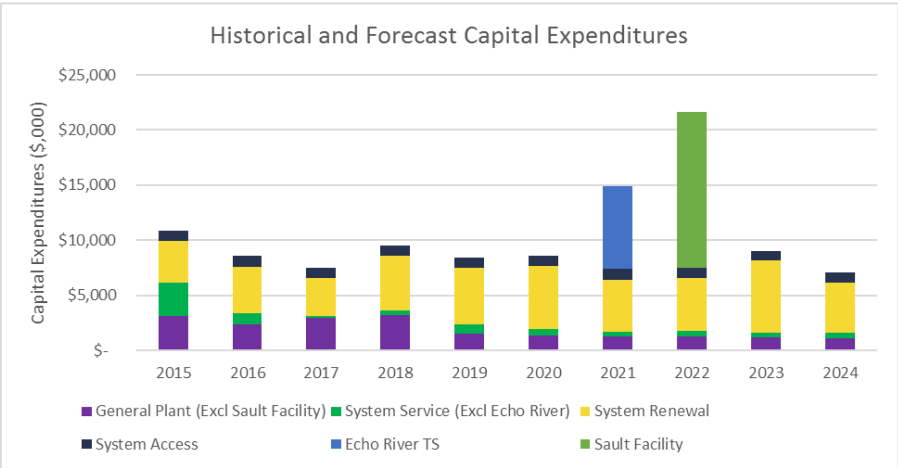
Website Link (For Application, Scorecard and Other Information): www.algomapower.com
Customer Service Email Contact: customerservice@algomapower.com

2020 Cost of Service Application

Customer Summary

SUMMARY OF ALGOMA POWER'S FIVE-YEAR PLAN

Algoma Power prepared a 2020-2024 Distribution System Plan that outlines its strategy and proposed spending levels for capital investments, and the ongoing operation and maintenance of its system. The following chart summarizes Algoma Power's actual and planned capital investments for 2015-2024:



OTHER PROPOSALS AND REQUESTS

The chart above shows large one-time projects planned for 2021 and 2022. Algoma Power is proposing an approach that would help pay these additional costs, while avoiding rate increases for the majority of customers that are eligible for rate subsidies (see "Rate Setting and Rate Relief").

Algoma Power's 2020 costs include integrating the distribution system in Dubreuilville, and Algoma Power is proposing an approach that avoids passing these costs onto its existing customers.

Algoma Power is also requesting a continued exemption from using time-of-use rates in the most remote portions of its system to avoid additional costs.

RATE SETTING AND RATE RELIEF

Algoma Power's forecasted 2020 costs of approximately $26 million includes operating costs, payments for capital investments that are spread over the life of the assets, the cost of debt and equity to support capital investments, and various taxes.

These total costs are divided between groups of customers (residential, commercial/industrial, seasonal and street lighting), and rates are calculated based on forecasted 2020 load and customer counts.

Revenue from seasonal and street lighting customers in 2015 was less than the costs assigned to them, requiring higher than inflationary rate increases for these customers from 2015 to 2019. Distribution revenues and costs are now in line which will limit 2021 to 2024 rate adjustments to inflationary increases.

Distribution rates for residential, commercial and industrial customers are subsidized by Rural and Remote Rate Protection (**RRRP)**. These customers pay significantly less than Algoma Power's calculated distribution rates. Rates for these customers are not tied to Algoma Power's costs, but instead are adjusted annually based on the average rate increase for all other distributors.

A number of other rate relief programs under the Fair Hydro Plan (lower time-of-use rates, caps on distribution rates for residential customers and credits for First Nation residential customers) are not affected by the application.

Finally, annual adjustments to transition residential and seasonal customers towards fixed monthly distribution rates continue to be applied.

BILL IMPACTS

For the distribution portion of the bill, API has forecasted increases of $2.33 for a typical residential customer (750 kWh per month) and $7.44 for a typical small commercial customer (2000 kWh per month). These adjustments are the result of the annual RRRP adjustment described above, and changes to rate riders for pass-through costs.

Website Link (For Application, Scorecard and Other Information): www.algomapower.com
Customer Service Email Contact: customerservice@algomapower.com

Appendix 1B

Algoma Power Inc.

2020 Cost of Service

EB-2019-0019

2020 BUSINESS PLAN

Algoma Power Inc.

Table of Contents

Table of Figures

1. Executive Summary

Algoma Power Inc. ("API") has developed this business plan to address the expectations of the OEB's *"Handbook for Utility Rate Applications"*, issued October 13, 2016. It outlines how the challenges associated with API's rural and rugged service area, API's core values and the preferences of API's customers have all been integrated into its cost of service application (the "Application") and Distribution System Plan ("DSP") in a manner that is consistent with the outcomes of the OEB's Renewed Regulatory Framework ("RRF"). This business plan also summarizes API's historical, target and forecasted performance with respect to performance metrics to ensure that API delivers on its strategic objectives.

API has established core values that are integrated into its planning process and daily activities, as well as objectives and principles that are integral to its asset management process. Section 2 of this document outlines these values and principles, and summarizes how they are aligned with the objectives of the RRF. Based on these values and principles, as well as the identified preferences of API's customers, strategic objectives are identified that drive projects and programs in the 2020-2024 period.

An overview of API and its ownership structure, service area, unique aspects and key challenges is provided in Section 3 of this business plan.

Section 4 focuses on the four categories of RRF outcomes, and discusses how these have informed the Application and DSP, with a particular focus on customer engagement activities specific to the application and the customer preferences identified through those activities.

Section 5 of this document summarizes performance metrics that have been considered during the planning process and that will be used to ensure that API delivers on its plans.

2. Guiding Principles and Strategic Objectives

2.1. Values and Principles

Algoma Power Inc. has established six core values that all employees should strive to promote and comply with each working day. To be effective, these values must be understood, communicated, reinforced and integrated into all our daily activities. Algoma Power's six core values are the following:

- **Respect for People:** Treat others as you would have others treat you. Honesty, integrity and ethics are never compromised.
- **Safety and the Environment:** Demonstrate a personal, unrelenting commitment to safety and environmental excellence. Protect yourself, your fellow employees, the public, and the environment.
- **Financial Success:** Produce solid earnings, with dividends that meet the expectations of our shareholders. Grow shareholder value through prudent equity investments and business partnerships. Ensure that debt obligations are always met in a timely manner and to the satisfaction of our creditors.
- **Customer Service:** Everyone has customers. Determine customer needs by listening. When you can meet these needs, do so; when you cannot, tell them you cannot – or tell them who can. When in doubt about how to treat a customer, do what you believe is right. When serving customers be pleasant, courteous and accurate; smile, act professionally and enjoy yourself…attitudes are contagious.
- **Productivity:** The old sayings hold true. Teamwork is key. Working smarter produces more gains than working harder. Mistakes are costly; get it right the first time. Job security comes from doing your job well, not from what job you do. Remember…if you have a better way to do something; just do it.
- **Community Involvement:** Each of us has an obligation to support the communities that support our employer. This means time as much as money. Success is measured by the reaction of community leaders and the opinions expressed by community residents.

In addition to the core values above, the fundamental objective of the API Asset Management Program ("AMP") is to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while minimizing both short and long term costs. This objective is met through the application of thorough and sound planning, prudent and justified budgeting, and ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital and operating plans.

API maintains a comprehensive AMP which outlines operating and capital processes, activities, and expenditures to ensure that API continues to provide safe, reliable, and efficient distribution of electricity to its customers. There are three key principles that are integral to API's asset management process:

- Meet the needs and expectations of its customers, as identified through regular customer engagement;
- Provide safe, reliable, and high-quality of service to all of the customers of API; and
- Satisfy the first two principles in a sustainable manner which minimizes the long-term costs to be borne by the ratepayers of API.

Finally, API is guided by the four categories of outcomes under the OEB's RRF, namely customer focus, operational effectiveness, public policy responsiveness, and financial performance. Additional information on how each of the RRF outcomes has influenced the Application and DSP is provided in Section 4.

The table below summarizes the relationship between API's core values, its asset management objectives and principles, and the RRF performance outcomes established by the OEB.

Table 1 – Values and Principles by RRF Outcome

RRF Performance Outcome	API Asset Management Objectives/Principles	API Core Values
Customer Focus	Meet the needs and expectations of its customers, as identified through regular customer engagement; Provide safe, reliable, and high-quality service; Minimize long-term costs to be borne by ratepayers;	Customer Service Respect for People Community Involvement Safety and the Environment
Operational Effectiveness	*Prudently and efficiently* manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner	Customer Service Productivity
Public Policy Responsiveness	Principles are derived from safety considerations; *acts, regulations, codes and guidelines*	Safety and the Environment
Financial Performance	Prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement *of all distribution assets in a sustainable manner*	Productivity Financial Success

2.2. Strategic Objectives

Based on the values and principles identified in Section 2.1, and the preferences of API's customers as identified through customer engagement, the following objectives are the primary driver of projects and programs identified in the 2020-2024 DSP:

- Sustaining End of Life Asset Replacement
- Sustaining Vegetation Management
- Worker and Public Safety and Environmental Protection
- Reliability Improvement – Focus on Reducing Outage Duration
- Facilities Improvements to Support Productivity and Efficiency
- Flexible Approach to Emerging Technology and Public Policy

Section 4.7 summarizes how each of the above objectives relates to RRF outcomes, API core values and/or customer-identified preferences.

2.3. Strategic Initiatives

The following projects and programs in the 2020-2024 DSP are planned in consideration of meeting the objectives identified above:

Sustaining End of Life Asset Replacement

API has continued all of its System Renewal Programs from the 2015-2019 DSP. Forecasted costs for the Line Rebuild and Express Feeder Rebuild programs are based on target replacement rates and historical unit costs. Forecasted costs for the Small Priority Replacement program, which replaces lower-value assets that have failed or have been identified as a high risk of failure, are based on a five-year historical average. Forecasted costs for Storm Damage reflect a declining trend over time.

Sustaining Vegetation Management Program

API's Vegetation Management Program ("VMP") is transitioning from a mix of capital and maintenance activity to a maintenance only program following the completion of the significant Right of Way ("ROW") Expansion and ROW Hardening programs. The intent of the maintenance program is to manage a variety of vegetation control and removal activities within the expanded ROWs on cycles that sustain clearances, address safety and reliability risk and are financially sustainable in the long term.

API has identified upward pressure on vegetation management costs as a risk in transitioning to a long-term maintenance-based VMP. In February 2019, API released a request for proposals related to portions of its VMP. Unit costs identified through this process were significantly higher than API's historical unit costs. Further investigation revealed that the Ontario market was experiencing above-average demand and a shortage of skilled labour due to an increase in the volume of vegetation work programs at other utilities. Despite the challenges that will inevitably result from this higher pricing, API has kept its annual VMP budgets in line with historical levels. API has structured its 2019-2020 VMP to gain a better understanding of the competitive market while transitioning to its maintenance only program. In order to gain a better understanding of the reasons for and the permanency of the identified increase in costs, API will collect additional data related to the actual volume of work completed by contractors. This will allow API to verify the quantification of required work and confirm/establish unit costs that are specific to API's service territory. With this information, API expects to be able to evaluate a range of options to source the long-term resources necessary to sustain its VMP in a cost-effective manner. Concurrently, API plans to pursue increased efficiencies through extending the use of and/or introducing new work practices such as more mechanized equipment and different herbicide applications.

Worker and Public Safety and Environmental Protection

All System Renewal projects and programs have inherent benefits with respect to worker and public safety and protection of the environment. By proactively replacing end of life assets on a planned basis, API can ensure that work is executed in a controlled manner, using work methods that provide the highest degree of project safety planning to protect its workers and the public. Further, API can plan the timing of this work to reduce impacts to species at risk and significant natural areas, and can consider alternative work methods or site access options as required. In contrast, reacting to sudden failures during outage and emergency situations often results in work being performed in unfavourable working conditions and with limited consideration of alternative access or work methods.

Several programs in other investment categories also have safety and environmental benefits. For example, the ROW Access program will establish more permanent access to certain remote sections of API's system, reducing exposure to hazards and the potential for environmental impact otherwise associated with emergency access. Further, new fleet purchases are typically safer and more fuel-efficient than the fleet equipment being replaced.

Reliability Improvement – Focus on Reducing Outage Duration

The installation of a second transformer at the Echo River TS is intended to reduce the risk of widespread and prolonged outages and/or significant power quality issues that could occur as a result of an identified contingency risk (failure of the T1 transformer) at this substation.

The continuation of API's Protection, Automation, Reliability program under the System Service category also allows for API to implement a variety of projects based on recommendations from third-party planning and reliability studies that will result in the greatest benefits to system reliability and contingency performance.

Facilities Improvements to Support Productivity and Efficiency

Prior to the expiration of the lease on its current Sault Ste. Marie facility that is shared with Hydro One, API assessed options and costs associated with extending this lease as compared to constructing its own facility elsewhere in Sault Ste. Marie. API concluded that a new facility is the preferred option to meet its operational needs. API expects the new facility to result in efficiency gains due to the consolidation of vehicle storage, material storage and handling, tool storage, and crew quarters that are scattered in this existing facility. API plans to construct the new building with an in-service date of 2022. The associated investment is included in the General Plant category, and API has proposed Advanced Capital Module treatment for this project.

This project builds on recent investments in API's service centres in the Wawa and Desbarats areas that also include similar consolidations of fleet and material storage to improve efficiency.

Flexible Approach to Emerging Technology and Public Policy

Certain reliability and SCADA investments in the System Service and General Plant categories will provide a foundation for future investments in DERs and Smart Grid.

In light of recent changes to public policy such as changes to the delivery of conservation programs and the repeal of the *Green Energy* Act, API has not included any other investments specifically related to connecting renewable energy, Distributed Energy Resources ("DER"), or implementation of Smart Grid. API's DSP does however include commitments to consider the use of DERs as a non-wires alternative to traditional investments on a case-by-case basis. API expects that emerging technologies will continue to mature and that public policy direction will continue to evolve over the forecast period and will incorporate consideration of emerging technologies into its planning process and its evaluation of alternatives as appropriate.

3. Utility Overview

3.1. Overview of the Service Area

Location and Geography

API's service area extends approximately 93 km east and 255 km north of the City of Sault Ste. Marie, covering approximately 14,200 km^2, which includes 7 First Nation Reserves, 14 organized townships, and a large number of unorganized townships. This vast service area is located in the Canadian Shield; a rugged and unyielding expanse of bare rock, lakes, muskeg, and trees. It also spans two different forest zones (the Great Lakes – St. Lawrence forest zone and the Boreal forest zone), with the result that the majority of API's distribution lines, 99% of which are overhead, are constructed through areas of dense vegetation.

Employment and Industry

Employment in API's service area has historically been driven by the natural resource, agricultural and tourism sectors. Development and maintenance of hydroelectric generation facilities has also been a large part of the economy, particularly in the Wawa to Montreal River area. Private and public sector service industries supporting these industries and local populations have also been large employers.

Approximately two thirds of API's customers are residential. Among these customers is a mix of customers employed by organizations in API's service area, and customers residing in API's service area but commuting to other municipalities for work, mostly in the City of Sault Ste. Marie. An aging population also means that API's residential class includes a large base of retirees. As of the 2016 census, the median age in the Algoma District was 49.0 years, compared to 41.3 years for Ontario as a whole. Commercial and Industrial customers currently comprise less than one-tenth of API's total customer base, with only 0.3% of all accounts having a demand greater than 50 kW.

The rugged wilderness, rural and remote nature, and recreational opportunities associated with API's service area attracts a relatively large seasonal population, with one-quarter of API's customer accounts classified as Seasonal.

Climate

The climate in API's service area is humid continental, which is characterized by large variations in seasonal temperatures including cold winters and warm, humid summers. Due to the size of its service area, temperatures and weather conditions are often quite varied between the northern and southern limits of its service area. The annual average temperature ranges from 2.1°C in Wawa to 4.7°C in Sault Ste. Marie. Daily average temperatures in Wawa and Sault Ste. Marie fluctuate from a low of approximately −10°C to −14°C in January to a high of approximately 15°C to 18°C in July and August. Weather extremes are more pronounced, with Wawa experiencing extreme minimum temperatures as cold as −50°C and Sault Ste. Marie experiencing extreme maximums of 36.8°C.

The entire API service territory is located on the leeward shore of Lake Superior. As a result, the region is prone to lake effect precipitation which occasionally limits API's ability to access portions of its service territory. In recent years, API has seen a number of severe storms, with significant precipitation, and winds approaching, and in some cases exceeding, current design standards. While API's distribution assets have generally withstood these weather conditions, the winds and associated precipitation have caused a large number of tree-related outages during major event days.

3.2. Utility Ownership

API is a wholly-owned subsidiary of FortisOntario Inc. ("FortisOntario"), which is headquartered in Fort Erie, Ontario. FortisOntario also owns Canadian Niagara Power Inc. (licensed transmitter and distributor), Cornwall Street Railway Light and Power Company Limited (licensed distributor), and a 5 MW natural gas cogeneration district heating plant located in Cornwall, Ontario (licensed generator). FortisOntario is the Ontario-based subsidiary of Fortis Inc. ("Fortis"), which is the largest investor-owned gas and electric distribution utility in Canada. FortisOntario subsidiary Wataynikaneyap Power PM Inc. acts as project manager for the Wataynikaneyap Power transmission project in Northwestern Ontario. FortisOntario holds a ten percent interest in each of three other licensed distributors: Westario Power Inc., Rideau St. Lawrence Holdings Inc., and Grimsby Power Inc.

With 2018 total assets of approximately $53 billion and annual revenues of approximately $8.4 billion, Fortis serves approximately 3.3 million gas and electricity consumers across Canada, the United States and the Caribbean. Fortis is a publicly traded company listed on the TSX and the NYSE.

3.3. Acquisition of Dubreuil Lumber Inc.

Since April 4, 2017, the distribution system of Dubreuil Lumber Inc. ("DLI") has been operated by API pursuant to an interim distribution licence that was issued by the OEB. API and DLI entered into an Asset Purchase Agreement (the "APA") on August 27, 2018, which contemplates the sale to API of DLI's distribution system, substantially in its entirety. DLI and API applied to the OEB on September 24, 2018 for approvals in connection with the APA and the incorporation of DLI's electricity distribution system into API's existing business. All elements of this business plan reflect a full integration of DLI's distribution system and customers, effective January 1, 2020.

3.4. Utility Description

API owns and operates the electricity distribution system in the district of Algoma, serving approximately 12,000 customers on a distribution system consisting of 1,861 kilometers of distribution line, with a resulting density of approximately 6.5 customers per kilometer of distribution line. Due to cold winters, a high penetration of electric heating, and a relatively low penetration of central air conditioning, API's distribution system is winter-peaking. Recent winter peak demand is in the range of 40-45 MW, with summer peak demand in the range of 25-35 MW.

API's vast service area and low customer density have resulted in a distribution system topology that is unique as compared to the majority of Ontario LDCs. API's distribution system is comprised of several distribution regions, operating independent of each other, that are either interconnected by API's own express feeders or are independently supplied through distinct transmission supply points. The large number of transmission supply points and the use of express feeders to supply vast areas in a transmission-like manner results in limited load transfer capability between API's various distribution regions. It also results in a disproportionate amount of customers and load being supplied by a small number of express feeders that are often located in remote areas with challenging terrain. These express feeders make up 14% of API's total line distance, but ultimately serve 72% of the total customer base and 76% of API's peak load.

3.5. Rate Subsidies

As a result of regulations made under the *OEB Act*, distribution rates for all of API's residential, commercial and industrial customers are subject to Rural and Remote Rate Protection ("RRRP"). Under the RRRP framework for API, distribution rates are adjusted annually based on the average distribution rate increase for all other electricity distributors in Ontario. During a cost of service year, a RRRP funding amount payable to API is calculated as the shortfall between the portion of API's revenue requirement allocated to the RRRP-eligible classes, and the forecasted revenue to be received from those classes at RRRP-subsidized rates. During subsequent IRM years, rate-setting for these classes and recalculation of the RRRP funding amount considers both the RRRP inflationary adjustments to rates and the price-cap IR factor that would otherwise be applicable to API.

Additional regulations made under the *OEB Act*, introduced concurrently with the Fair Hydro Plan, further reduce amounts payable by residential customers. The Distribution Rate Protection ("DRP") program limits the base monthly distribution charge for residential customers of 8 electricity distributors, including API, to the equivalent fixed rate for the lowest-cost of the 8 distributors. Further, for residential on-reserve customers, the First Nations Delivery Credit ("FNDC") program results in on-bill credits that offset the entire delivery line of the bill, which includes rate riders, pass-through transmission rates, and the cost of system losses.

3.6. Key Challenges

The following key challenges resulting from API's vast and heavily-forested service area, as described above, have been factored into the strategic objectives and strategic initiatives identified in Section 2 of this Business Plan:

- **Vegetation Management:** API must continue to manage vegetation along its rights of way in a sustainable manner, with consideration of safety, cost, reliability, and access.
- **Low Customer Density:** API's vast service area and low customer density means that more assets such as substations, distribution lines, and transformers are required to serve a typical customer as compared to other distributors. API must balance meeting the needs and expectations of its residential and general service customers (whose rates are decoupled from API's costs as a result of RRRP and DRP subsidies), and its seasonal and street lighting customers (whose rates remain directly tied to API's costs).
- **Limited Localized Distribution:** Related to its low customer density, the topology of API's distribution system results in extensive use of express feeders and long radial lines, limited clustering of customers, and little interconnection between distribution regions. API must therefore focus on the reliability of its transmission supply points, express feeders, and substations, particularly with respect to contingency planning for equipment failure to mitigate the risk of prolonged system outages.
- **Land Related Issues:** API must ensure that the impact of planned investments and planned maintenance activities respects the variety of land rights and other rights held by First Nations, Municipalities, Crown agencies, and private landowners. Further, API's work activities for any given project or activity must consider a variety of legislation related to protection of the environment and significant natural areas.
- **General Access Issues:** Sections of API's distribution system are not accessible by public roads and rights of way. API must therefore continue to establish and maintain formal access agreements with property owners and land rights holders, and must also maintain suitable off-road equipment to access various portions of its distribution across challenging terrain. In some cases, API must also establish and maintain access trails and appropriate landing or docking sites for aircraft and watercraft.
- **System Reliability Challenge:** All of the challenges listed above impact API's ability to either prevent outages, minimize the customer impact of an outage, or effectively restore its system to a normal operating condition. In making choices related to spending on different projects and programs, API must assess trade-offs between maintaining historical reliability levels, implementing technologies to improve reliability, and reducing the risk of prolonged widespread outages during system contingencies.

Each of the above challenges is addressed in further detail in Sections 2.1.1.1 to 2.1.1.6 of API's DSP.

4. Outcomes of the Renewed Regulatory Framework

On October 18, 2012, the OEB issued its "*Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*." The report set out a comprehensive performance-based approach for the Renewed Regulatory Framework ("RRF") which is an evolution to an outcomes-based approach, in consideration of four key categories:

- Customer Focus
- Operational Effectiveness
- Public Policy Responsiveness
- Financial Performance

This section describes how API continues to improve in understanding the needs and expectations of its customers, and how API's core values, the needs of its customers, and the RRF outcomes are integrated and prioritized in its planning activities.

4.1. Customer Focus

Customer and stakeholder education and engagement has long been a central component of API's planning process. Given the expansiveness of its service area and the variety of customers and other stakeholders, API employs a variety of education and engagement approaches that includes customer satisfaction surveys, community outreach/stakeholder sessions, forestry outreach, conservation and demand management interactions, and other supporting engagement activities. API strives to continuously enhance its engagement activities, as well as to seek feedback to understand which engagement and communication channels are considered to be the most effective by its customers. Since its 2015 cost of service application, API has implemented a more formal approach to education and engagement with respect to its distribution system planning process, as described in Section 4.2.

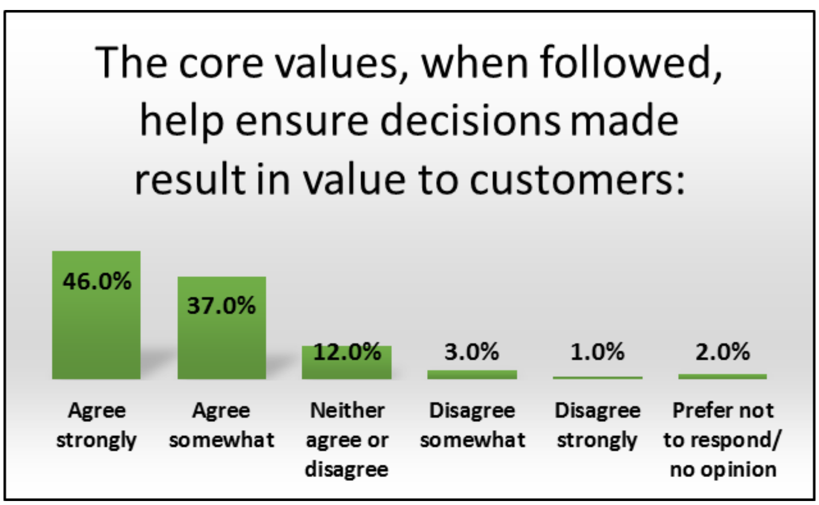
4.2. Enhanced Customer Engagement

Since 2015, API has augmented its annual telephone based satisfaction survey with additional questions to gain additional insight into the needs and preferences of its customers. For example, in the 2018 telephone survey customers were asked to prioritize 12 items which can affect costs.

In advance of its 2020 cost of service application, API partnered with UtilityPulse and co-developed a multi-channel approach to gathering wisdom, insights, information and feedback from customers. This approach reviewed the results of historical telephone surveys and other customer engagement activities to develop a seven-chapter online survey (the "Taking AIM" surveys) tailored to API's DSP and the Application. In addition to the primary goal of understanding the needs and preferences of API's customers, these surveys included educational components, and opportunities for customers to share their wisdom and/or comments at various points throughout the survey process. The survey process allowed for completion of any or all of the seven chapters, and provided incentives for participation to increase response rates. Following completion of these surveys, UtilityPulse prepared a comprehensive report, which is included as **Appendix A**.

4.3. Identification of Customer Needs and Preferences

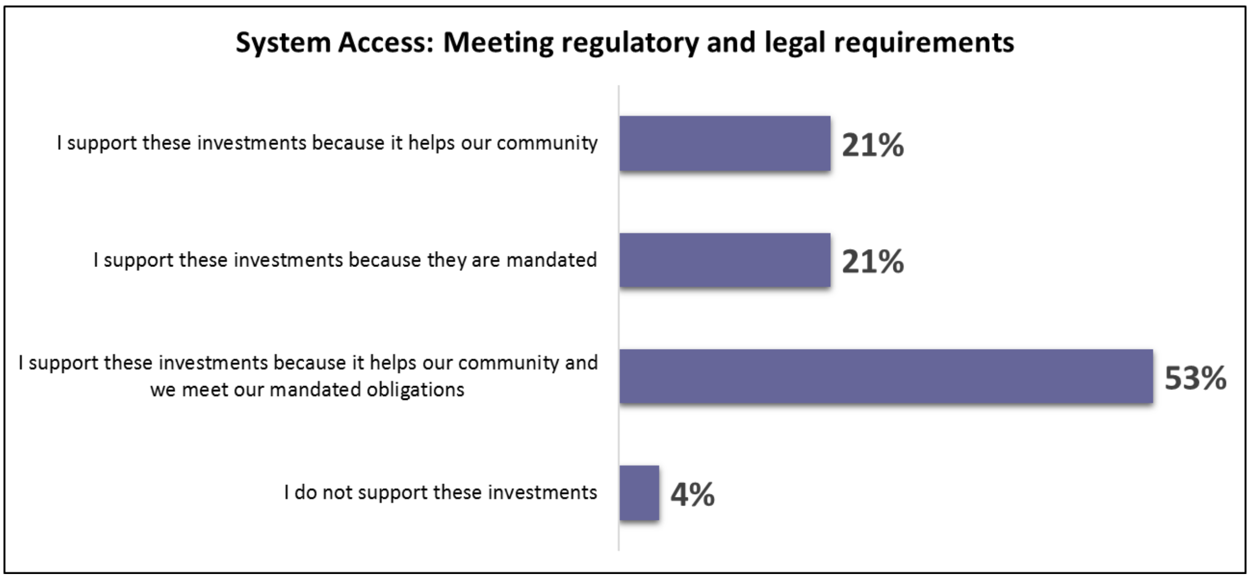
When presented with information on API's core values during the Taking AIM surveys, a full 83% of respondents agreed that "these values, when followed, help ensure decisions made result in value to customers." Only 4% of customers disagreed with this statement, while the remaining 14% were either neutral or non-responsive to the question. As summarized in Section 2.1, API takes guidance in its planning process from the alignment of its core values, asset management principles, and the OEB's RRF outcomes. API is therefore confident that this approach reflects value to its customers.

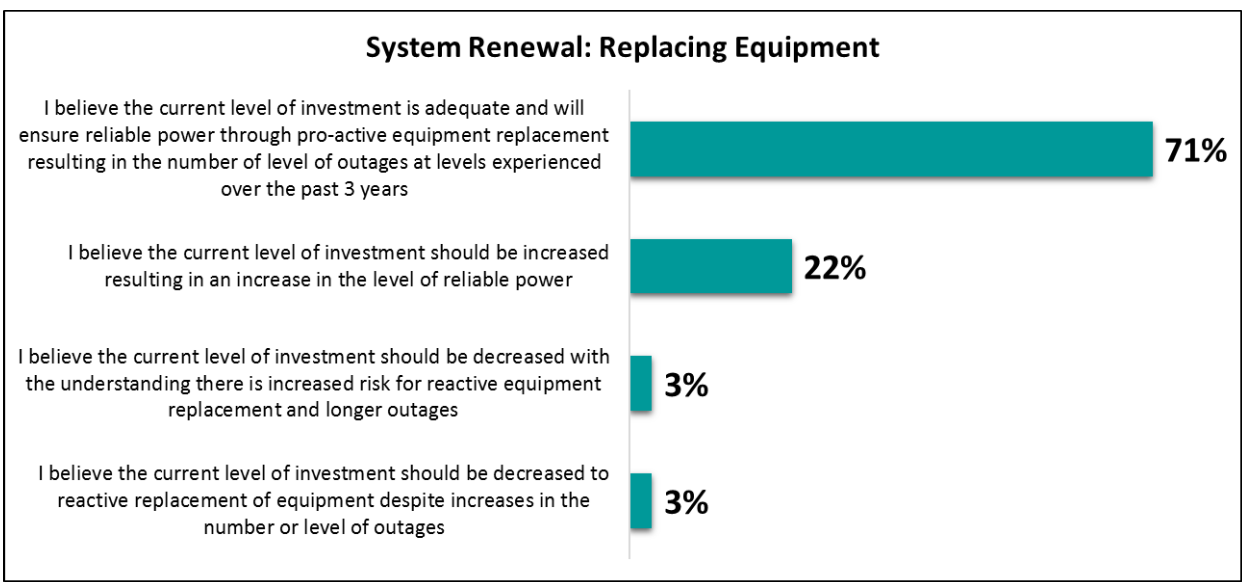


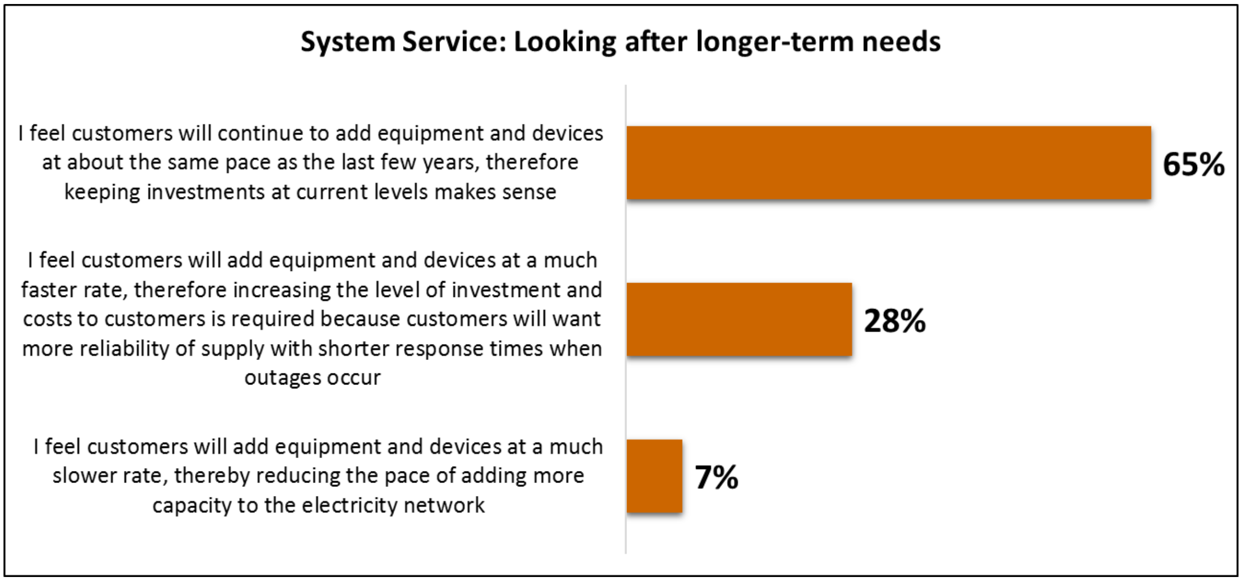
Chapter 5 of the Taking AIM survey was designed to familiarize customers with the types of investments associated with the four investment categories in API's DSP (System Access, System

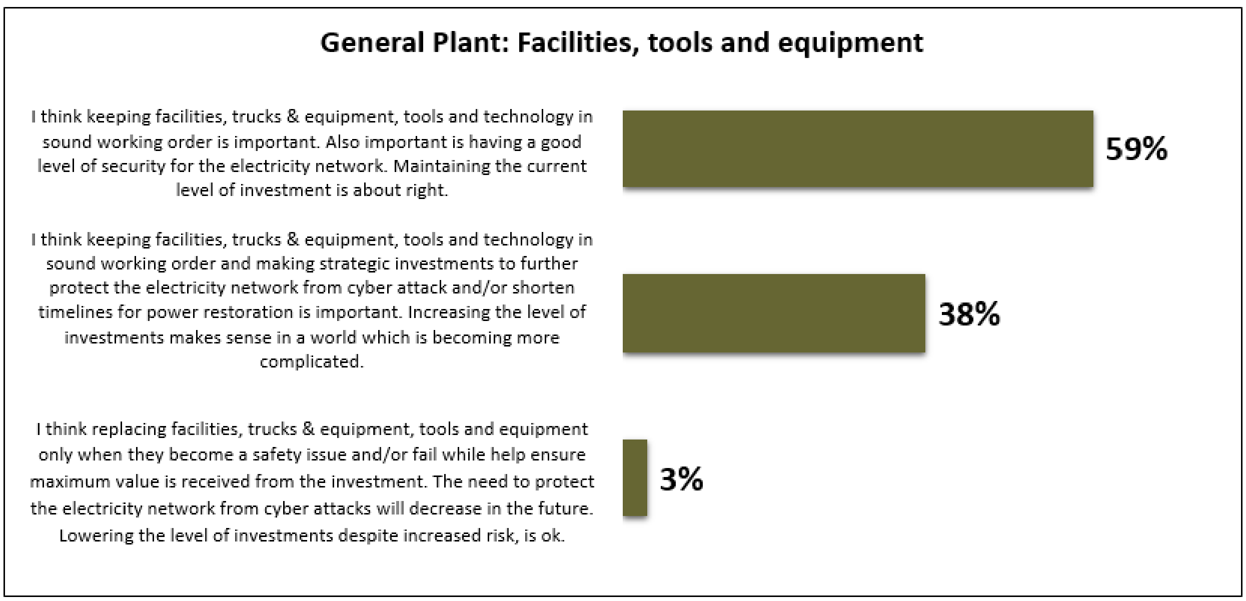
Renewal, System Service and General Plant), and to seek customer input on the pacing and relative level of investment associated with each category.

For System Access investments, survey responses indicate that customers understand the mandatory nature of the investments, and that only 4% of customers do not support the investments. For the other three categories, survey responses indicate that vast majority of customers support either maintaining investments at currently levels, or even increasing investment levels. Across all investment categories, no more than 7% of respondents supported a decrease in investment, as indicated in the charts below.

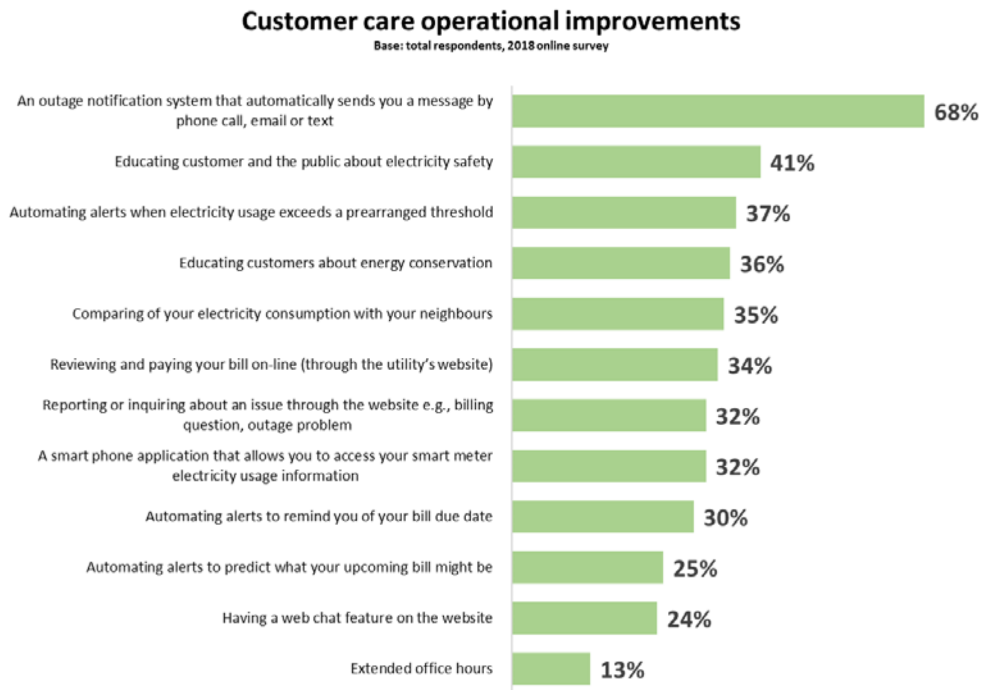








Chapter 6 of the Taking AIM survey was focused on understanding customer preference, and willingness to pay for operational improvements related to customer care and satisfaction, as well as to gain insights on criteria important to customers related to API's plans for its facilities. Survey results indicate that a majority of customers are willing to pay for enhanced and automated outage notification, but that less than half of customers are willing to pay for other customer care initiatives:



Based on the above results, API will ensure that business system integration efforts over the 2020-2024 period target implementation of automated outage notifications.

The purpose of Chapter 7 of the Taking AIM survey was to assess customer preferences and priorities with respect to proposed investments in API's Application. The survey also assessed customer confidence in API's ability to prioritize capital investments and explained its rate setting process to customers at a high level. The survey presented API's recommended approach to setting investment levels for each of System Renewal, System Service, General Plant, and Vegetation Management, asking respondents to choose between API's recommendation and several alternative approaches. The intent of this approach was to re-assess customer support for the approach to investment in each category (as compared to Chapter 5) within the context of their identified priorities and of overall costs.

The survey results indicated that the number one identified customer priority was to keep costs low, followed by maintaining the safety and reliability of the network. 74% of respondents stated that they were either "very confident" or "somewhat confident" in API's ability to use good judgment in prioritizing capital investment projects. While support for investment levels differed from the results of the Chapter 5 survey, 52-62% of respondents supported either inflationary increases or greater than inflationary increases in investments across all categories. Only 8% of total respondents did not support any increase for any of the four categories.

Questions regarding customer perceptions on reliability, the impact of outages, and customer priorities were integrated into several chapters of the Taking AIM survey as well as previous telephone surveys. Customers consistently indicated that reducing the duration of outages was a greater priority than reducing the frequency of outages. In particular, approximately one third of respondents reported that outages longer than 4 hours become a potential health issue, or a safety and security issue. Even greater numbers of respondents rated the impact of such outages as stressful, annoying, or inconvenient.

4.4. Operational Effectiveness

With respect to the RRF outcome of operational effectiveness, distributors are expected to achieve continuous improvement in productivity and cost performance, while delivering on reliability and quality objectives.

API's cost performance, according to the OEB PEG Benchmarking model, shows an improving trend over the ten-year period comprising its 2015-2019 and 2020-2024 DSPs. At the same time, API's scorecard shows consistent safety performance and improving system reliability over the most recent five-year period. These metrics are discussed in additional detail in Section 5.

4.5. Public Policy Responsiveness

Distributors are expected to deliver on obligations mandated by government.

Between 2009 and 2017, API has connected 3 FIT projects and 129 microFIT projects to its system without triggering a need for major system expansions. API has consistently met or exceeded all prescribed timelines for processing applications and connecting these projects.

As of December 31, 2018, API achieved 71% of its 7.51 GWh energy savings target under the 2015-2020 Conservation First Framework, while spending only 65% of its approved budget.

Since the IESO ceased accepting new applications under the FIT and microFIT programs, and the provincial government has announced a wind down of the Conservation First Framework, API anticipates that metrics and targets related to public policy responsiveness will evolve during the 2020-2024 period covered by its DSP.

4.6. Financial Performance

Under the RRF, distributors are expected to achieve improvements in efficiency that are sustainable, while maintaining financial viability and earning a fair return. Historical financial results are discussed in Section 5.7 of this Business Plan.

4.7. RRF Impact on DSP

As described in Section 2.1, there is significant alignment between the OEB's RRF outcomes, API's asset management principles and objectives, and API's core values. Results of the Taking AIM customer engagement survey also indicate that following its core values during the planning process will help ensure decisions made result in value to customers. With this in mind, API identified the following Strategic Objectives for its 2020-2024 DSP:

Sustaining End of Life Asset Replacement

Replacement of end of life assets on a relatively level and sustaining basis, in accordance with API's end of life replacement strategy for each asset type was a key component of the 2015-2019 DSP, and remains a focus for the 2020-2024 DSP. This strategy is aligned with API's asset management objectives, as well as the OEB's goals in the RRF. Further, a majority of API's customers support API's existing equipment replacement practices and continued investment in the System Renewal category, with at least inflationary increases. API continues to improve in its collection, reporting and analysis of condition based data, undertaking a formal asset condition assessment and a number of other third-party studies that support the System Renewal investments in its 2020-2024 DSP.

Sustaining Vegetation Management

API has historically made significant investments in expanding its Right of Way ("ROW") width through its ROW Expansion program, which was completed in 2011. Further, in 2018 API completed the majority of the ROW Hardening Program, removing a backlog of hazard trees to stabilize (harden) the edge of the expanded ROW. The focus for the current DSP period (2020-2024) is on transitioning API's vegetation management program to a full maintenance phase. This maintenance program is a key component of maintaining and improving on the reliability, safety and environmental objectives that are described below.

Worker and Public Safety and Environmental Protection

As a core value, API expects a commitment to safety and environmental excellence to be integrated into all of its activities, including its distribution system planning processes. In addition to agreeing with API's core values generally, continuous improvements with respect to safety and enhancing public education related to electrical safety consistently rate as high priorities with API's customers. Finally, safety related metrics are a key component of the OEB scorecard as it relates to operational effectiveness. The majority of projects and programs in the DSP have primary drivers other than safety or the environment; however, consideration of safety and environmental protection must remain an area of focus in the prioritization and scoping of projects, as well as in the identification of work methods and timing for project execution. Sustaining investments in fleet, tools and ROW access in the General plant category must ensure that workers have the necessary tools, equipment and access required to perform their jobs safely.

Reliability Improvement – Focus on Reducing Outage Duration

As described in Section 4.3, API's customers have indicated a preference for focusing on reducing the duration of outages over reducing the frequency of outages, and have identified that outages longer than 4 hours can result in health issues as well as safety and security issues. API must therefore focus on improving its response time to outages, and improving contingency configurations and contingency plans at the transmission supply point and sub-transmission/substation level to reduce the risk of widespread long-duration outages. At the same time, API is aware that the number one priority of its customers is to keep costs low. As a result, apart from a large one-time supply point reliability project deferred from 2017 to 2021, System Service investments represent a relatively low portion of the overall five-year capital plan, with ongoing reliability-driven investments being focused on the most cost-effective investments to reduce outage duration and contingency risk.

Facilities Improvements to Support Productivity and Efficiency

Continuous and sustained improvements in productivity and efficiency are key themes of the RRF. From a facilities perspective, 88% of respondents to API's 2018 online survey agreed that each of the following items related to API's facilities were very or somewhat important:

- Design of facilities encourages labour efficiency;
- Facilities meet needs of customers; and,
- The decision to renovate or build new should be based on which option represents the best balance between keeping costs low, being efficient, and meeting customer longer term energy needs.

Historical investments in API's Wawa and Desbarats service centres are expected to have a positive impact on the productivity and efficiency of staff working from those locations as a result of improvements to fleet, material and tool storage in the new facilities. API expects similar improvements for staff working from its Sault Ste. Marie facility when the proposed new facility is built in 2022. In addition to improving productivity and efficiency, API's renewed facilities are expected to reduce response times to outages, particularly during storms and in the winter months.

Flexible Approach to Emerging Technology and Public Policy

API acknowledges that Public Policy Responsiveness is a key outcome under the RRF. However, historical performance metrics have focused on connection of renewable energy and LDC-led conservation programs, both programs whose future is uncertain following the 2018 change in government. Policy statements from the current government related to energy have been focused on keeping costs low and finding further sources of cost savings. The focus on keeping costs low is aligned with the preferences of API's customers, who have also rated investments in green energy and smart grid technologies as lower priorities.

In its DSP, API has therefore reflected a commitment to consider the use of DERs as a non-wires alternative to traditional investments on a case-by-case basis, but expects to do so with a focus on cost-benefit to its customers, and consideration of the risks associated with emerging technologies, as opposed to opportunities to pilot new technology. API expects to adapt its DSP as required in response to evolving public policy.

5. Performance Metrics and Targets

On March 5, 2014, the OEB issued its *"Report of the Board – Performance Measurement for Electricity Distributors: A Scorecard Approach"*. The resulting OEB Scorecard contains a set of performance measures and standards to assess distributor performance against the four categories of RRF outcomes identified in Section 4.

This section discusses API's performance in relation to each of the OEB Scorecard performance measures over the last five years. Targets for future performance are also discussed, with an emphasis on specific performance measures identified as important to customers and performance measures that have significantly influenced the development of API's 2020-2024 DSP.

Prior to discussing individual OEB Scorecard performance measures, additional context is provided in relation to the OEB's LDC benchmarking efforts in consideration of API's circumstances, as well as API's capital investment plans and operational costs that underpin a number of cost control metrics and financial ratios presented later in this section.

5.1. OEB Benchmarking

As a rural, remote and low-density LDC, API has historically struggled with interpreting the results of the OEB's OM&A and total cost approaches to benchmarking in a meaningful way. As early as the April 2007 PEG report there was a recognition of the challenges associated with benchmarking API (Great Lakes Power at the time), and acknowledgement that models other than those ultimately adopted by the OEB may be more appropriate for benchmarking API on a total cost basis:

> *For example, the translog model may do a better job of recognizing the special cost challenges faced by a company that, like Great Lakes Power, has extremely low customer density.*[1]

In the same report, in determining appropriate peer groups for comparison of results, OEB Staff moved Great Lakes Power into a group of its own due to low customer density.[2] Subsequently, API put forward an analysis of cost drivers in the PEG total cost econometric benchmarking model in its 2014 IRM application (EB-2013-0110), submitting that these cost drivers and resulting coefficients are based on an industry average, and not representative of API as a statistical outlier. In its decision and order in the EB-2013-0110 application, the OEB found that:

> *Algoma's evidence illustrates that the PEG model, although applicable to the vast majority of distributors, may not apply to distributors that are particularly unique.*[3]

[1] Benchmarking the Costs of Ontario Power Distributors, Pacific Economics Group, April 25, 2007 (PEG 2007), p.57
[2] PEG 2007, p.74
[3] EB-2013-0110, Decision and Order, February 20, 2014, pp.7-8

Despite the challenges that API has faced in respect of prior OEB benchmarking efforts, API is able to make use of trending information and other output from the PEG model, as discussed in Section 5.5. API remains optimistic that some of the benchmarking metrics being considered in the OEB's Activity and Program Based Benchmarking initiative (EB-2018-0278) will accurately reflect differences in business conditions and cost drivers between LDC's at a more granular level, and will therefore more accurately assess API's efficiency and performance.

5.2. Capital Investments

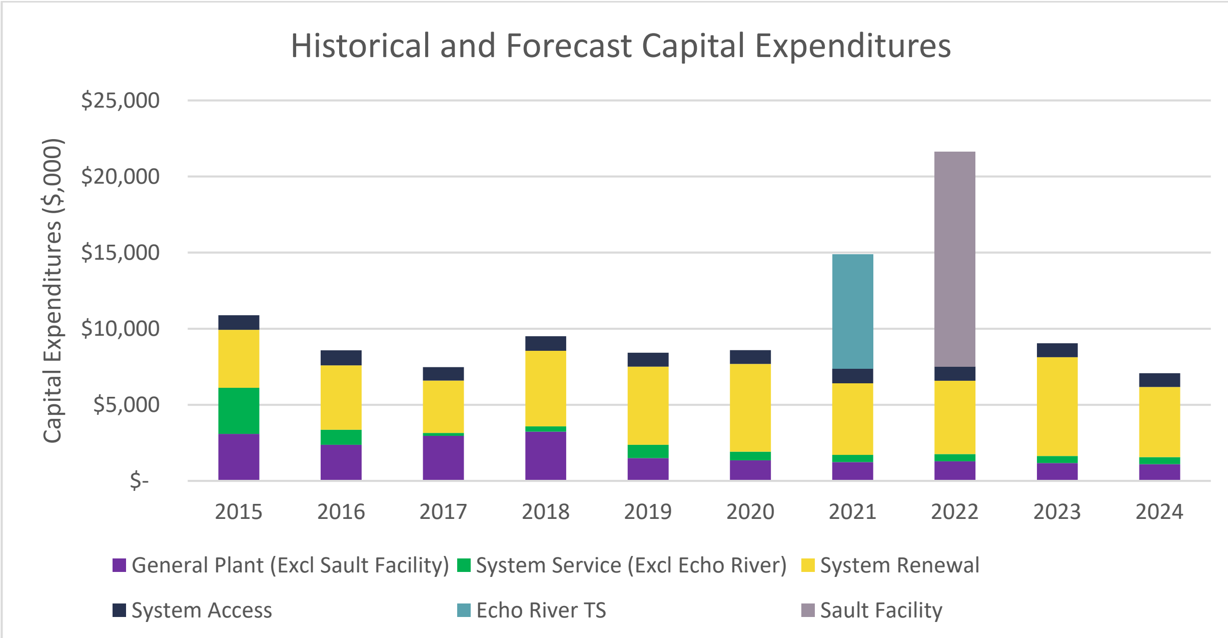
The following table summarizes API's historical capital investments, as well as forecasted investments in the 2019 Bridge Year, and the 2020-2024 period covered by its current DSP:

Table 2 – Historical and Forecast Capital Expenditures

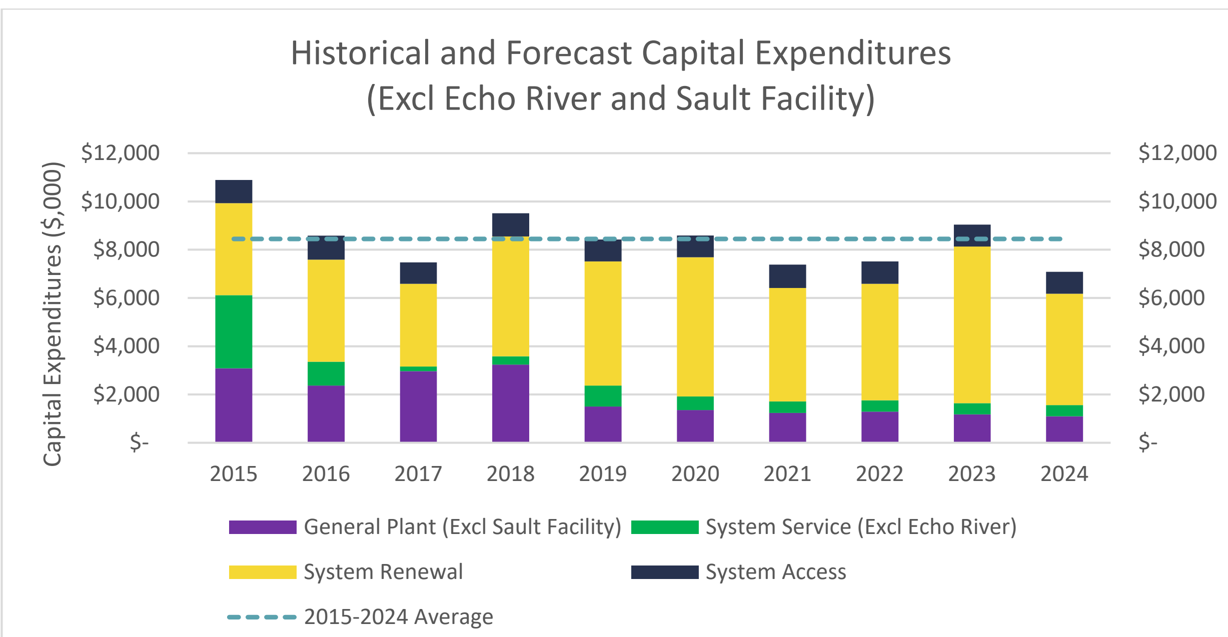
Category	Historical ($ '000)					Forecast ($ '000)				
	2015	2016	2017	2018	2019[4]	2020	2021	2022	2023	2024
System Access (Gross)	963	992	883	960	913	903	963	930	906	906
System Renewal (Gross)	3,809	4,229	3,434	4,971	5,144	5,765	4,700	4,822	6,494	4,616
System Service (Gross)	3,033	990	192	339	868	562	7,978[2]	472	461	461
General Plant (Gross)	3,084	2,369	2,963	3,240	1,500	1,357	1,238	15,408[3]	1,178	1,098
Gross Capital Expenses	10,889	8,580	7,472	9,510	8,425	8,588	14,879	21,633	9,039	7,081
Contributed Capital	-157	27	-137	-69	-140	-102	-100	-100	-100	-100
Net Capital Expenses after Contributions	10,732	8,607	7,336	9,441	8,285	8,486	14,779	21,533	8,939	6,981

API's capital planning process strives for relatively consistent year to year spending in its sustaining end of life asset replacement programs as well as other programs of a recurring nature. This approach allows API to optimize the use of internal resources and ensures asset replacement on a pace that is consistent with the expected useful life of each type of asset. Larger one-time projects such as substation rebuilds and facility rebuilds are also paced to keep spending consistent, to the extent possible. Over the period covered by the 2020-2024 DSP, investments are required in the Echo River TS and the Sault Facility, resulting in large one-time variances from average levels of capital spending in both 2021 and 2022[5], as shown in the following chart:

[4] Values are split into Historical and Forecast based on the period covered by each DSP; 2019 values in this table are based on forecasted spending
[5] API is requesting Advanced Capital Module (ACM) treatment for these two projects



The Echo River TS and Sault Facility projects are consistent with the 2020-2024 strategic initiatives identified in Section 2.3 and additional justification for each project is provided in Section 4.4 of API's 2020-2024 DSP. Excluding these two projects, actual and forecasted capital spending is relatively consistent over the 2015-2024 period:



API has consistently and cost-effectively completed the majority of projects and programs identified in its 2015-2019 DSP, particularly in the System Access and System Renewal categories. Occasionally, more discretionary projects and programs in the System Service and General Plant categories have been reprioritized during API's annual budgeting process. Detailed explanations for changes in strategy in relation to SCADA and facility investments in the 2015-2019 period are provided in Section 4.3.2 of the current DSP.

API's target with respect to capital investments in the 2020-2024 period is to complete all of the projects and program-based replacements identified in its DSP. API will however maintain flexibility to reprioritize projects and/or adjust replacement rates based on updates to the inputs to its asset management process.

5.3. Operations, Maintenance and Administration (OM&A) Costs

The following table summarizes API's historical and forecasted OM&A costs for the 2015-2024 period:

Table 3 – Historical and Forecast OM&A Costs

Category	Historical ($ '000)					Forecast ($ '000)				
	2015	2016	2017	2018	2019[6]	2020	2021	2022	2023	2024
Operations	1,417	1,297	1,452	1,566	1,790	1,782	1,809	1,836	1,864	1,892
Maintenance	4,879	5,065	5,264	5,145	5,226	5,298	5,377	5,458	5,540	5,623
Billing and Collecting	965	876	874	920	970	995	1,010	1,026	1,041	1,056
Community Relations	24	32	48	142	95	97	98	99	101	102
Administrative and General	4,530	4,535	4,494	4,361	4,843	5,505	5,588	5,671	5,756	5,843
Total	11,816	11,804	12,132	12,135	12,924	13,677	13,882	14,091	14,302	14,516

Historical year-over-year variances have ranged from 0-3%. Drivers of larger cost increases for the 2019 Bridge Year and the 2020 Test Year include:

- Filling a unionized position that became vacant in 2017 and was redefined in 2018;
- Increases to rental and permit fees paid by API, partly due to increases in the OEB's generic joint use charges, and offset by increases in other revenues;
- Increased IT costs related to addressing the requirements of the OEB's Cybersecurity Framework;
- Increased finance staff to enhance processes and controls over financial and regulatory reporting;
- Lower than typical 2018 costs due to short-term staffing reductions in a number of Administrative areas due to vacancies and effort allocated to a non-distribution project;

[6] Values are split into Historical and Forecast based on the period covered by each DSP; 2019 values in this table are based on forecasted spending

- Increases in Sault Ste. Marie building rent following lease renewal/extension; and,
- Delayed recovery of certain costs related to the 2017-2019 interim operation of the distribution system owned by Dubreuil Lumber Inc. ("DLI"), as well as certain transaction and integration costs related to the acquisition of the customers and electricity distribution assets of DLI.

API's target for the 2020-2024 forecast period is to keep average OM&A cost increases to approximately 1.5% (i.e. less than inflation), consistent with the price-cap adjustment factors inherent in the OEB's IRM rate-setting framework.

5.4. Scorecard Metrics – Customer Focus

The OEB Scorecard contains six performance metrics related to the RRF outcome of Customer Focus, divided into categories of Service Quality and Customer Satisfaction.

Service Quality

API's historical performance has consistently exceeded OEB targets in all three Service Quality metrics, as summarized in the following charts produced from the OEB's Electricity Utility Performance Dashboard. API's future target is to maintain performance that meets or exceeds OEB targets and is consistent with historical performance levels.

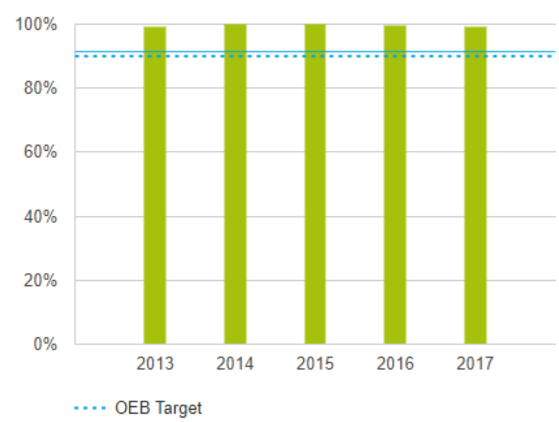
SERVICE QUALITY

New residential/small business services connected on time

99.24% (2017)

The utility must connect new service for the customer within five business days, 90 % of the time, unless the customer agrees to a later date. This timeline depends on the customer meeting specific requirements ahead of time (such as no electrical safety concerns in the building, customer's payment information complete, etc.)

✓ Target met



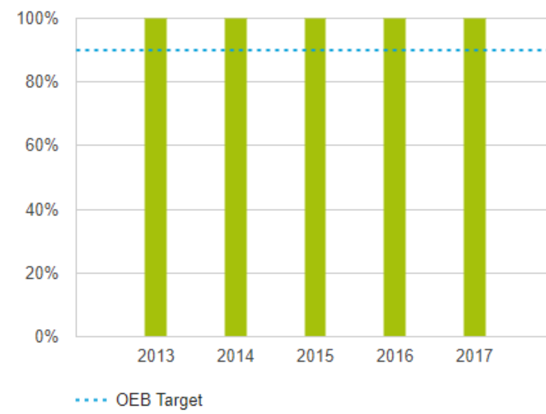
SERVICE QUALITY

Scheduled appointments met on time

100% (2017)

For appointments during the utility's regular business hours, the utility must offer a window of time that is not more than four hours long, and must arrive within that window, 90 % of the time.

✔ Target met



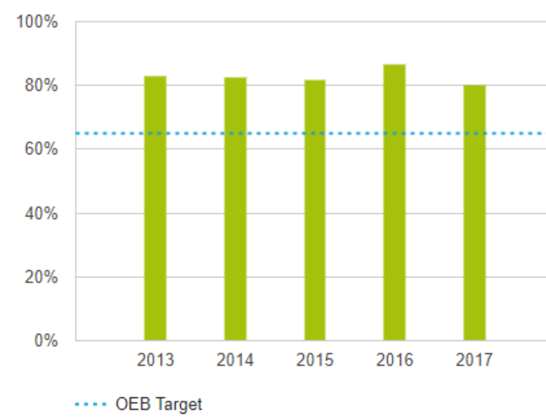
SERVICE QUALITY

Telephone calls answered on time

80.06% (2017)

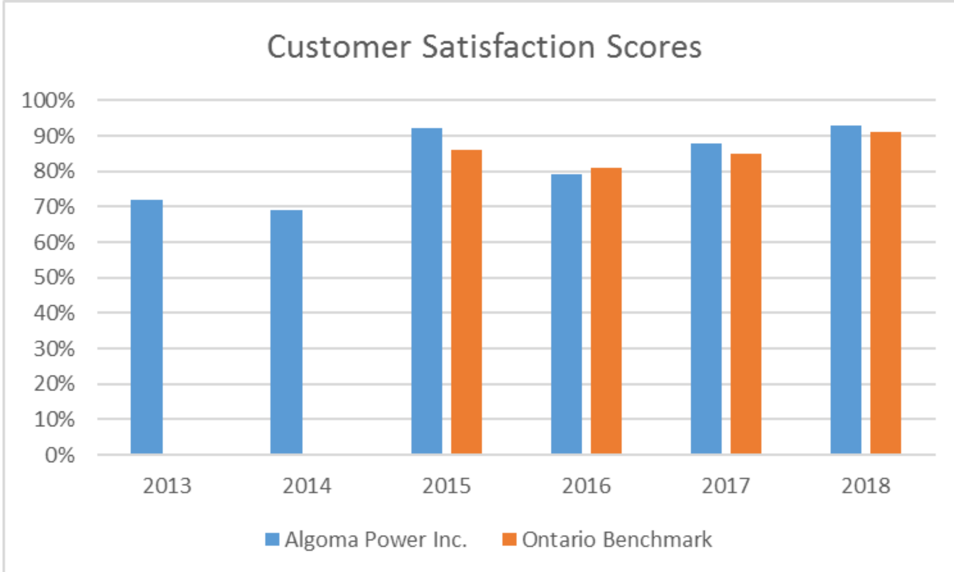
During regular call centre hours, the utility's call centre staff must answer within 30 seconds of receiving the call directly or having the call transferred to them, 65 % of the time

✔ Target met



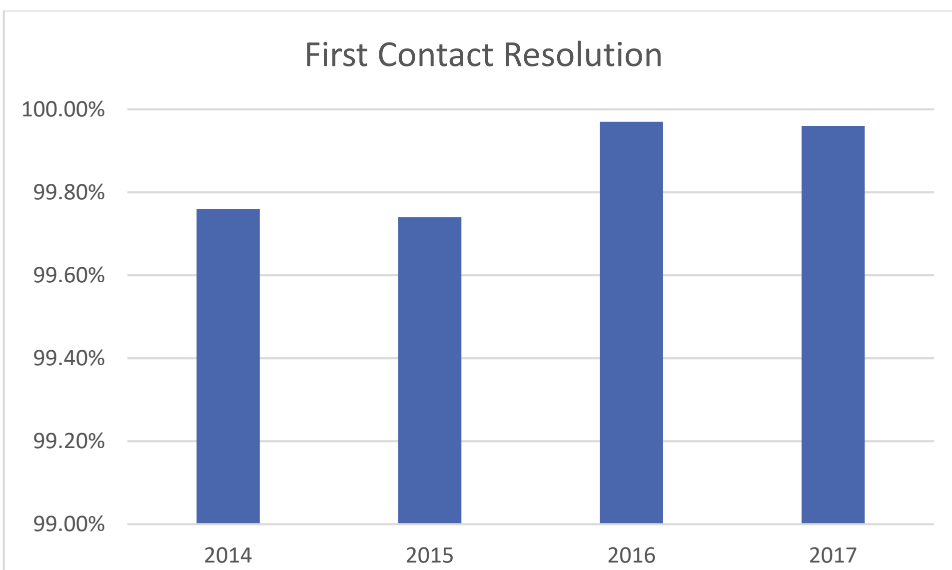
Customer Satisfaction

API conducts annual customer satisfaction surveys to better understand and meet the needs of its customers. Since 2015, this survey has been completed by UtilityPULSE, which has allowed API to compare its results to an Ontario Benchmark that reflects the results of other LDCs working with this same provider. While the OEB has not set specific targets for customer satisfaction scores, the following results indicate both an upward trend in API's overall customer satisfaction score, and a level of customer satisfaction that exceeds the Ontario Benchmark in three of the past four years.



API's experience with customer satisfaction scores since 2015 is that year to year variations in its own results are generally similar to variations in the Ontario Benchmark, which can be driven by factors beyond API's control. In 2018, API conducted additional customer engagement activities related to its 2020 cost of service application (as described in Section 4.2), with the intent that a more granular understanding of customer preferences would inform the development of its DSP in a way that would meet customer expectations over the 2020-2024 planning period. API's future target is to continue to achieve customer satisfaction scores that exceed the Ontario Benchmark.

First Contact Resolution is a measure of the percentage of inbound calls that are resolved by the first point of contact (i.e. not escalated to a supervisor or more senior staff member). Less than 1% of calls have historically required escalation, and API expects to continue this level of performance.



The OEB target for Billing Accuracy is 98%. API has consistently exceeded this target, and intends to continue this performance level in future years.

CUSTOMER SATISFACTION

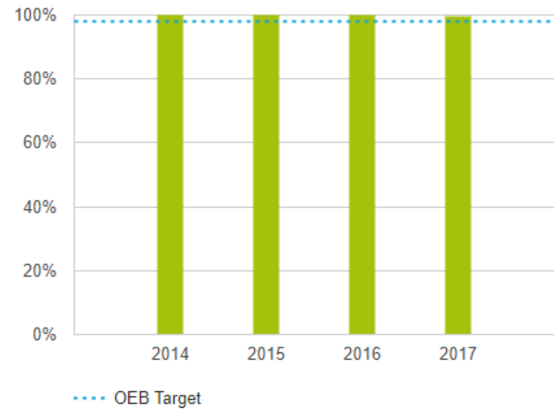
Billing accuracy

99.48% (2017)

An important part of business is ensuring that customer's bills are accurate. The utility must report on its success at issuing accurate bills to its customers.

More information about billing accuracy

Target met



5.5. Scorecard Metrics – Operational Effectiveness

The OEB Scorecard contains ten performance metrics related to the RRF outcome of Operational Effectiveness, divided into categories of Safety, System Reliability, Asset Management and Cost Control.

Safety

An unrelenting commitment to safety is entrenched in API's core values and a focus on both worker and public safety will always be included among API's strategic objectives.

In 2015 and 2017, UtilityPULSE was engaged to complete surveys in relation to "Public Awareness of Electrical Safety". On completion of this survey, UtilityPulse generated a "Public Safety Awareness Index Score" for API and other LDC's. API's 2015 score was 81%, and its 2017 score was 82%. This survey will continue to be completed on a biannual basis. API plans to continue to deliver and improve on its public outreach initiatives related to safety, with a goal on improving its Public Safety Awareness Index Score with each survey.

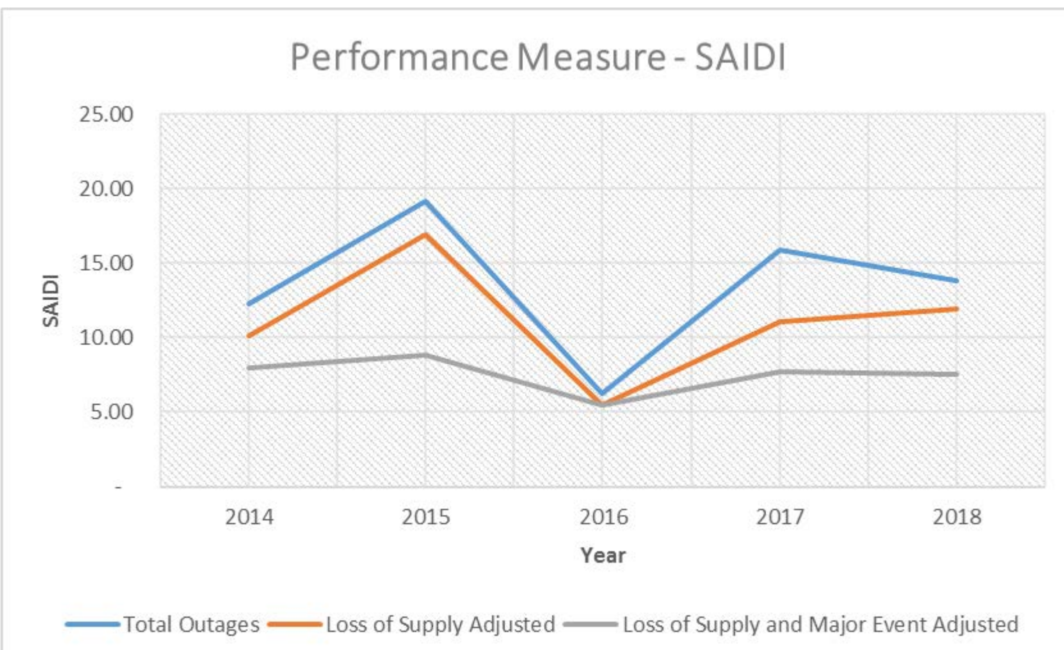
Over the 2013-2018 period, API has consistently achieved full compliance with Ontario Regulation 22/04, and has had no serious electrical incidents involving the public. API's target is to continue to achieve full compliance and to have zero serious safety incidents.

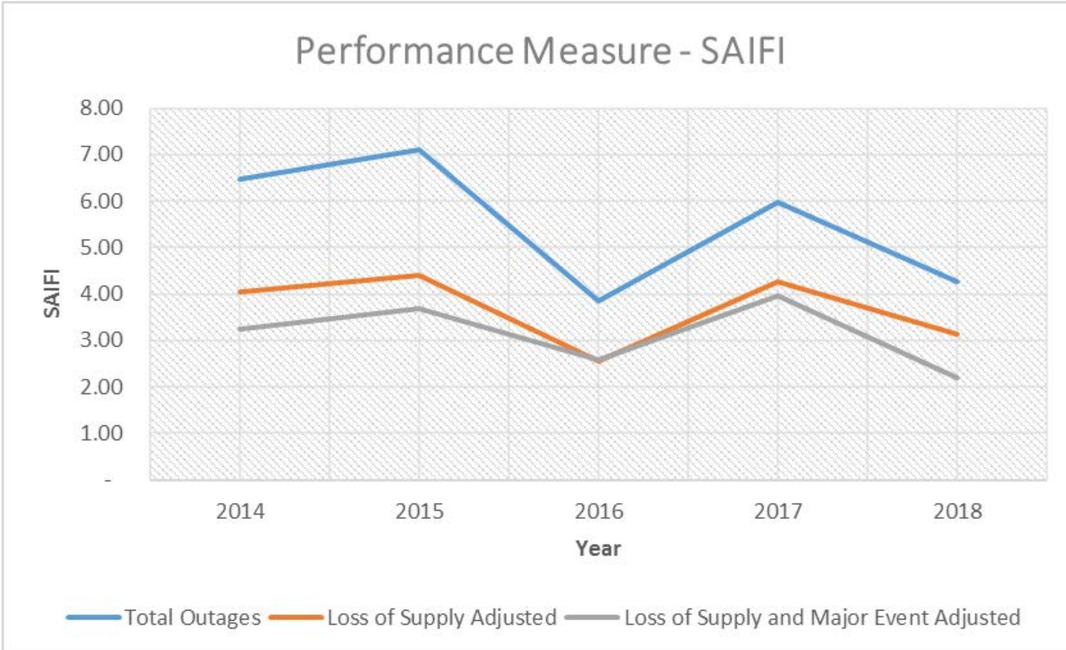
System Reliability

The OEB Scorecard includes SAIDI and SAIFI performance metrics that provide an indication of the average number of hours and the average number of times that power to a customer is interrupted. Scorecard results are adjusted to focus on outages that are within the LDC's control by removing outages associated with Loss of Supply, and Major Event Days. API's target is to achieve adjusted reliability results in any given year that are better than its historical rolling 5-year average.

In API's experience, while customers are more understanding of outages during major storm events, all outages, regardless of cause or responsibility, ultimately affect customers' perceptions of the reliability of API's system. API therefore regularly reviews SAIDI and SAIFI results and trending for all outages and adjusted values.

As described in Section 4.3, API's customers have indicated that API should prioritize efforts to reduce outage duration and response times. Section 4.7 describes DSP projects and programs that focus on reliability improvement.





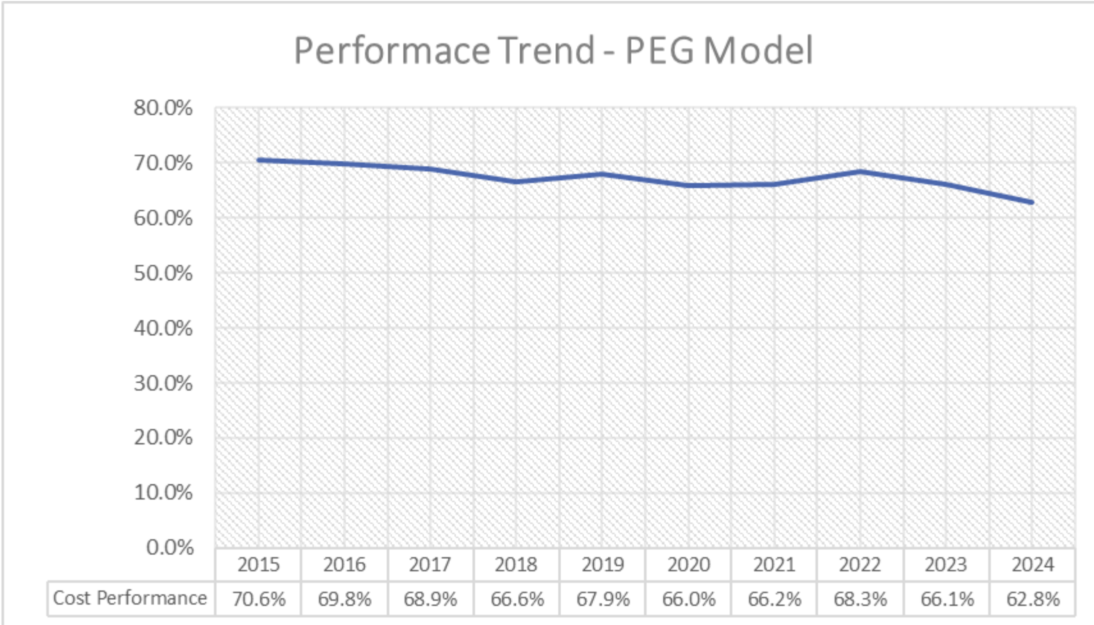
Asset Management

From 2014-2018, API has reported its Distribution System Plan Implementation Progress as "In Progress" for 2014 and 2017, as a result of certain projects being deferred to 2015 and 2018. API reported implementation progress as "Complete" for all other years. Further details on historical and forecasted capital spending is provided in Section 5.2.

Cost Control

Cost control performance metrics included in the OEB Scorecard are driven by the output of the OEB's total cost benchmarking framework, particularly the Total Cost Benchmarking model compiled and updated by Pacific Economics Group (the "PEG Model"). API's historical challenges with the PEG Model are summarized in Section 5.1. As a result of these issues, API has focused on trending and cost drivers in its analysis of historical results and setting of future targets.

The PEG Model calculates each LDC's "Actual Total Cost" by adding the majority of OM&A accounts from the LDC's trial balance, and determining a proxy for capital costs based on historical and current capital additions, an asset price index, an economic depreciation rate, and a rate of return. The PEG Model also calculates a "Predicted Total Cost" for each LDC, using a standard formula that considers business conditions such as number of customers, load, km of line, etc. The percentage difference between actual and predicted cost is the PEG Model measure of cost performance, where lower percentage results indicate greater efficiency. The following chart shows API's cost performance, according to the PEG model:



For the reasons summarized in Section 5.1, API does not believe that the PEG model cost predictions accurately reflect the cost drivers inherent to API's distribution system and service area. Since API's inputs to the PEG Model remain relatively stable year-over-year however, the trending in cost performance provides useful insight into whether API's cost efficiency is improving over time. The 2015-2024 trend indicates that API's is becoming more efficient over the ten-year period covered by its past and current DSPs. Annual variations in the results can be caused by one-time capital additions, such as the Sault Facility investment in 2022, and as such, API is focused on the overall trend as opposed to slight variability in the year-over-year results.

The OEB Scorecard also includes metrics related to total cost per customer and total cost per km of line, where total cost is based on PEG model calculations. Based on API's actual and forecasted costs for the 2015-2024 period, API increases in each of these metrics, assuming no increases to line km or system load, and assuming minimal growth in customer counts. The forecasted compound average growth rate over the 2015-2014 period is 2.34% in cost per customer and 2.75% in cost per km of line. These values reflect inflationary increases in OM&A costs and the largely sustaining capital investment plans included in API's historical and current DSPs, with minimal customer growth, and essentially no change to total line km.

5.6. Scorecard Metrics – Public Policy Responsiveness

The OEB Scorecard contains three performance metrics related to the RRF outcome of Public Policy Responsiveness, divided into categories of Conservation & Demand Management and Connection of Renewable Generation.

API has consistently met or exceeded OEB targets related to completing impact assessments and connecting renewable generation on time. Also, as of December 31, 2018, API achieved 71% of its 7.51 GWh energy savings target under the 2015-2020 Conservation First Framework, while spending only 65% of its approved budget.

Since the IESO ceased accepting new applications under the FIT and microFIT programs, and the provincial government has announced a wind down of the Conservation First Framework, API anticipates that metrics and targets related to public policy responsiveness will evolve during the 2020-2024 period covered by its DSP.

5.7. Financial Performance

Scorecard Metrics – Financial Performance

The following table summarizes API's Scorecard financial ratios for the 2013-2018 period:

Table 4 – Scorecard Financial Ratios

<table>
<tr><th colspan="2"></th><th>2013</th><th>2014</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th></tr>
<tr><td colspan="2">Liquidity: Current Ratio (Current Assets/Current Liabilities)</td><td>1.99</td><td>2.33</td><td>1.14</td><td>1.10</td><td>0.37</td><td>1.04</td></tr>
<tr><td colspan="2">Leverage: Total Debt (short-term and long-term debt) to Equity Ratio</td><td>1.25</td><td>1.22</td><td>1.12</td><td>1.02</td><td>1.17</td><td>1.42</td></tr>
<tr><td rowspan="2">Profitability: Regulatory Return on Equity</td><td>Deemed</td><td>9.85%</td><td>9.85%</td><td>9.30%</td><td>9.30%</td><td>9.30%</td><td>9.30%</td></tr>
<tr><td>Achieved</td><td>7.06%</td><td>8.38%</td><td>11.07%</td><td>9.89%</td><td>8.11%</td><td>8.22%</td></tr>
</table>

API's future target is to achieve its deemed return on equity while maintaining liquidity and leverage ratios that are relatively consistent with historical levels.

Revenue Requirement / Revenue Deficiency

The following table presents API's Revenue Requirement trend from the 2015 Board Approved to 2020 Test Year:

Table 5 – Trend in Revenue Requirement

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Particular	**2015 Board Approved**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
OM&A Expenses	$12,304,881	$11,815,559	$11,803,904	$12,131,721	$12,134,596	$12,924,455	$13,677,187
Depreciation Expense	$3,899,209	$3,136,802	$3,326,205	$3,438,399	$3,600,160	$3,796,858	$4,043,341
Property Taxes	$107,800	$115,453	$112,102	$113,924	$115,938	$119,000	$118,600
Total Distribution Expenses	$16,311,890	$15,067,814	$15,242,211	$15,684,044	$15,850,694	$16,840,313	$17,839,128
Regulated Return On Capital	$6,561,398	$6,417,885	$6,830,093	$7,088,901	$7,299,850	$7,679,811	$7,763,963
Grossed up PILs	$409,653	$581,009	$440,903	$475,362	$560,067	$196,748	$333,974
Service Revenue Requirement	**$23,282,941**	**$22,066,708**	**$22,513,207**	**$23,248,307**	**$23,710,612**	**$24,716,872**	**$25,937,065**
Less: Revenue Offsets	-$466,758	$68,748	$144,840	$434,381	$164,157	$189,388	-$51,889
Base Revenue Requirement	**$22,816,183**	**$22,135,456**	**$22,658,047**	**$23,682,688**	**$23,874,769**	**$24,906,260**	**$25,885,176**

API's 2020 cost of service application is intended to set rates that will recover the 2020 base revenue requirement identified in Table 5 above. Table 6 on the following page illustrates that revenues at current rates are insufficient to recover this revenue requirement, resulting in a net revenue deficiency of $2,192,853.

Table 6 – Calculation of 2020 Revenue Deficiency

	At Current Approved Rates	At Proposed Rates
Revenue Deficiency from Below	$ -	$2,983,473
Distribution Revenue	$23,692,323	$22,901,703
Other Operating Revenue Offsets - net	$51,889	$51,889
Total Revenue	$23,744,213	$25,937,065
Operating Expenses	$17,839,128	$17,839,128
Deemed Interest Expense	$3,458,109	$3,458,109
Total Cost and Expenses	$21,297,237	$21,297,237
Utility Income Before Income Taxes	$2,446,975	$4,639,828
Tax Adjustments to Accounting Income per 2013 PILs model	($3,379,548)	($3,379,548)
Taxable Income	($932,573)	$1,260,280
Income Tax Rate	26.50%	26.50%
Income Tax on Taxable Income	$333,974	$333,974
Income Tax Credits	$ -	$ -
Utility Net Income	$2,113,001	$4,305,854
Utility Rate Base	$119,873,438	$119,873,438
Deemed Equity Portion of Rate Base	$47,949,375	$47,949,375
Income/(Equity Portion of Rate Base)	4.41%	8.98%
Target Return - Equity on Rate Base	8.98%	8.98%
Deficiency/Sufficiency in Return on Equity	-4.57%	0.00%
Indicated Rate of Return	4.65%	6.48%
Requested Rate of Return on Rate Base	6.48%	6.48%
Deficiency/Sufficiency in Rate of Return	-1.83%	0.00%
Target Return on Equity	$4,305,854	$4,305,854
Revenue Deficiency/(Sufficiency)	$2,192,853	$ -
Gross Revenue Deficiency/(Sufficiency)	$2,983,473	

6. Appendices

Appendix A	API 2017 OEB Scorecard and MD&A
Appendix B	"Taking AIM" Report (2018 Online Survey)

Appendix A

2020 BUSINESS PLAN

Algoma Power Inc.

Scorecard - Algoma Power Inc.

9/24/2018

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	2016	2017	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		99.00%	100.00%	100.00%	99.40%	99.24%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		82.90%	82.60%	81.90%	86.60%	80.06%		65.00%	
	Customer Satisfaction	First Contact Resolution			99.76%	99.74%	99.97%	99.96%			
		Billing Accuracy			99.88%	99.85%	99.85%	99.48%		98.00%	
		Customer Satisfaction Survey Results		72.0%	69%	92%	79%	88%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness				81.00%	81.00%	82.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		7.00	7.96	8.80	5.46	7.68			10.62
		Average Number of Times that Power to a Customer is Interrupted [2]		2.94	3.24	3.68	2.57	3.95			4.46
	Asset Management	Distribution System Plan Implementation Progress			In Progress	Completed	Completed	In Progress			
	Cost Control	Efficiency Assessment		5	5	5	5	5			
		Total Cost per Customer [3]		$1,952	$1,980	$2,107	$2,126	$2,116			
		Total Cost per Km of Line [3]		$12,302	$12,483	$13,306	$13,453	$13,408			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Cumulative Energy Savings [4]				13.73%	31.19%	63.08%			7.51 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			100.00%	100.00%					
		New Micro-embedded Generation Facilities Connected On Time		96.88%	100.00%	100.00%	100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.99	2.33	1.14	1.10	0.37			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.25	1.22	1.12	1.02	1.17			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.85%	9.85%	9.30%	9.30%	9.30%			
			Achieved	7.06%	8.38%	11.07%	9.89%	8.11%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend:
5-year trend: up, down, flat
Current year: target met, target not met

2017 Scorecard Management Discussion and Analysis ("2017 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2017 Scorecard MD&A: **http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf**

Scorecard MD&A - General Overview

In 2017, API continued to meet or exceed the majority of its performance targets.

In 2018, API expects to continue to improve its overall scorecard performance results as compared to previous years. These performance improvements are expected as a result of enhanced system reliability due to API's investment in its distribution system and continued responsiveness to customer feedback.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2017, API connected 99.2% of the 132 new eligible low-voltage residential and small business customers within the Ontario Energy Board's prescribed five day timeline. Since 2011, API has consistently met the Ontario Energy Board's target of 90%.

- **Scheduled Appointments Met On Time**

In 2017, API met 100% of its 342 appointments within the prescribed timelines set out by the Ontario Energy Board. Since 2013, API has consistently met attended 100% of its schedule appointments on time.

- **Telephone Calls Answered On Time**

In 2017, customer service representatives answered 80.06% of its 14,613 calls within 30 seconds. This exceeds the Ontario Energy Board's mandated 65% target. Longer call processing times due to the complexity of customer calls are affecting the call answering statistics. API continues to offer and promote self-serve options and utilizes social media to engage and inform customers in an effort to offer customers additional channels to interact with the Company.

Customer Satisfaction

- **First Contact Resolution**

API measured First Contact Resolution by tracking the number of escalated calls as a percentage of total calls taken by the customer service center. In 2017, less than one percent of calls were escalated.

- **Billing Accuracy**

For 2017, API issued approximately 157,866 invoices and 99.48% were accurate. This is above the industry standard of 98%.

- **Customer Satisfaction Survey Results**

In 2015, API moved to a new third party survey provider, UtilityPULSE, to be more consistent with other LDCs in the province. The survey size was expanded and general service customers were included in the telephone survey. The phone numbers were randomly selected and were stratified so that 85 per cent of the interview were conducted with residential customers and 15 per cent with general service customers. The 2017 satisfaction score was 88%, which is higher than the Ontario benchmark of 81%.

The survey provides useful information to better meet the needs of API's customers and is incorporated into the distribution system plan, capital planning and overall company objectives.

Safety

- **Public Safety**
  - **Component A – Public Awareness of Electrical Safety**

In 2017, UtilityPulse was also engaged to complete surveys in relation to "Public Awareness of Electrical Safety". On completion of this survey, UtilityPulse generated a "Public Safety Awareness Index Score" for API and other LDC's. Province-wide scores ranged from 78% to 86%, with both average and median Index Scores of 83%. API's score of 82% suggests that members of the public are generally well-informed about the safety hazards associated with electrical distribution systems, but also that further education and engagement would be beneficial. This survey on "Public Awareness of Electrical Safety" is completed on a two-year cycle and will be completed again by API in 2019.

- **Component B – Compliance with Ontario Regulation 22/04**

This component includes the results of an Annual Audit, Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. All the elements are evaluated as a whole and determine the status of compliance (Non-Compliant, Needs Improvement, or Compliant).

Results provided by ESA, API's status for 2017 is Compliant.

- **Component C – Serious Electrical Incident Index**

"Serious electrical incidents", as defined by Regulation 22/04, make up Component C. The metric details the number of and rate of "serious electrical incidents" occurring on a distributor's assets and is normalized per 10, 100 or 1,000 km of line (10km for total lines under 100km, 1000km for total lines over 1000km, and 100km for all the others).

Results provided by ESA, API had zero incidents in 2017.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

API's customers experienced an increase in the average duration of electrical service disruptions in 2017 compared to 2016. The 2017 result is better than the OEB's performance target, and better than the results of 2014 and 2015. The largest contributors are in the categories of tree contact and planned outages.

API continues to invest in grid modernization in order to gain visibility on the state of the distribution system and improve overall response and restoration times. Grid modernization initiatives include the deployment of automated devices and implementation of an outage management system. API understands that reliability of electrical service is a high priority for its customers and continues to invest in replacement of end-of-life assets as well as vegetation management.

- **Average Number of Times that Power to a Customer is Interrupted**

API's customers also experienced an increase in the average number of electrical service disruptions in 2017 as compared to prior years, however the 2017 result is better than the OEB's performance target.

API has deployed several initiatives aimed at reducing the number of electrical service interruptions such as the vegetation management program and cyclical asset preventative maintenance programs.

API reviews outage statistics on a monthly basis to identify areas of poor distribution system performance. This process indicates any trends in poor performance and identifies opportunities to improve reliability. API also completes asset condition assessments to identify assets that present a risk of impacting system reliability. API uses reliability indicators and asset condition assessment data as key drivers into the system planning process.

Asset Management

- **Distribution System Plan Implementation Progress**

API continues to implement the 2015-2019 Distribution System Plan approved in its last rate application. Notably, a large substation project originally planned for 2017 has been deferred while API conducts additional planning studies and continues to engage its transmission supplier to evaluate alternatives.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the Ontario Energy Board to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In reviewing the Pacific Economics Group benchmarking and report, API management does not believe that the model accurately predicts API's costs. API's unique attributes as a rural distributor, particularly its low customer density, result in API being an extreme outlier in the data set used to develop the model.

Some of API's largest cost drivers, including customer density and the degree of forestation along its distribution line rights of way, are not appropriately reflected in the benchmarking model. As a result of the extremely rural and low density nature of API's system in relation to other Ontario distributors, API management believes that the total cost per km of line section below provides a more appropriate measure of API's efficiency and cost control.

- **Total Cost per Customer**

The statistical model developed by Pacific Economics Group produces total capital and operating costs for each distributor that can be used for the purpose of comparing distributors. This amount is then divided by the total number of customers that API serves to determine Total Cost per Customer. The cost performance result for 2017 is $2,116 per customer which is a 0.5% decrease over 2016.

Over the 2013 to 2017 period covered by the scorecard, API faced both inflationary cost increases, as well as cost increases associated with investments in programs for asset replacement, system improvement, and vegetation management that are sustainable in the long term. From 2013 to 2017, API's total customer count has essentially stayed the same (11,655 in 2013 vs. 11,724 in 2017), with a result that cost increases are not offset by customer growth.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that API operates to serve its customers. API's 2017 result is $13,408 per km of line, a 0.3% decrease over 2016.

Many of API's significant cost drivers are directly related to its total kilometers of line. These cost drivers include most lines and forestry related activities, as well as support functions such as engineering and design. As discussed in the Efficiency Assessment section above, API management believes that total cost per km of line is a more accurate assessment of API's cost efficiency.

Over the 2013 to 2017 period covered by the scorecard, API's total km of line has increased by only 2 km, or 0.1%. As a result, annual changes in the cost per km result are simply reflective of changes in API's overall costs.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

On the basis of the IESO's "Final 2017 Annual Verified Results Report" issued on June 29, 2018, API achieved 63.08% of its Net Energy Savings target for the 2015 – 2020 timeframe. API fully leveraged the suite of Independent Electricity System Operator ("IESO") province-wide demand management programs and placed emphasis on supporting the conservation efforts of large commercial, industrial and institutional customers.

Much of this success can be attributed to the successful promotion of energy efficiency programs and strong participation by commercial customers in the Retrofit and Small Business Lighting Programs.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

API did not receive any requests for renewable generation connections requiring Connection Impact Assessments in 2017.

- **New Micro-embedded Generation Facilities Connected On Time**

In 2017, API connected one (1) new micro-embedded generation facility (microFIT projects of less than 10 kW). This facility was connected within the prescribed time frame of five business days. The minimum acceptable performance level for this measure is 90% of the time. API works closely with its customers and their contractors to make the connection process as streamlined and transparent as possible.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

The 2017 liquidity current ratio for Algoma Power Inc. is 0.37 (2016 1.10). The liquidity ratio has decreased due to an increase in due to related parties of $8.0 million over prior year. The 2017 liquidity current ratio based on API's audited financial statements, adjusted for due to related parties, is 1.26 (2016 1.68), which is an indication that API is appropriately leveraged. Going forward, the liquidity ratio is expected to move back towards the 5 year average of 1.39.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The Ontario Energy Board uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5. The combined 2017 leverage debt to equity ratio for API is 1.17 (2016 1.02). The leverage ratio is line with the past several years and going forward it is expected to be held relatively constant.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

API's 2017 distribution rates were approved by the Ontario Energy Board as part of its 4th Generation Incentive Rate-Setting application. API's last Cost of Service application was for rates effective January 1, 2015 and this included an expected (deemed) regulatory return on equity of 9.30%. The Ontario Energy Board allows a distributor to earn within +/- 3% of the expected return on equity.

- **Profitability: Regulatory Return on Equity – Achieved**

API's return achieved in 2017 was 8.11% (2016 9.89%), which is within the +/- 3% range allowed by the Ontario Energy Board. API achieved returns are lower in 2017 as compared to 2016 due to a $0.6 million (15.5%) decrease in adjusted regulated net income and a $3.0 million (2.9%) increase in rate base.

Note to Readers of 2017 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Appendix B

2020 BUSINESS PLAN

Algoma Power Inc.

Taking A.I.M.

(Applied Insights Methodology)

Executive summary

The Age of Understanding

In a world where customers have experienced a tremendous range of emotions, as it relates to overall electricity costs over the past 5 years, the challenge for Algoma Power (API), and other LDCs as well, is to demonstrate it cares about keeping costs low. And, it is focused on ensuring the electricity network is maintained, renewed and modernized in ways which are meaningful to its customers.

Algoma Power has taken a multi-method approach to engaging customers so it could understand the wide variety of opinions and views about what it takes to be seen as successfully running an LDC. Information, data, and feedback gathered from a customer population who are looking through a "lens of costs" tends to be more past-oriented rather than future-oriented. A written comment from one customer respondent: "*I don't really know how you can reduce costs without compromising performance. Everything costs money. I just don't want higher bills."*

Most organizations and Algoma Power is not an exception, want to believe people will make rational decisions. That is when truthful information and facts are presented a person will make a rational decision. This isn't so; decisions are irrational. Findings from Algoma Power's Customer Engagement (CE) activities show there were 8% of online survey respondents who won't support any increase for any reason. From the 8%, one respondent provided the following written comment: *"I'd rather have a cheaper bill than investing more into making the system more complicated."* However, there were 37% of online survey customer respondents who would support all of Algoma Power's recommendations, or something more than their recommendation, for System Renewal, System Service, General Plant, and Vegetation Management. (See Chapter Survey #7) A customer respondent comment affirms: *"I think Algoma Power Inc is doing a great job and I support their new ideas in this avenue."* The remaining 55% had exhibited a wider range of views.

Algoma Power also understands the Customer engagement activities supporting the Cost of Service application, such as online and telephone surveys, means customer respondents would be asked difficult questions --- all of which have complicated answers. It isn't surprising then, on average, 16% of customer respondents selected "Don't know" as their answer regarding the recommendations for investments, which affects costs, in System Renewal, System Service, General Plant, and Vegetation Management. Despite the difficult questions, 73% of customer respondents said they were "very + somewhat confident" in the people at Algoma Power to use good judgment for prioritizing capital investments projects. (See Chapter Survey #7)

What were the Customer Engagement (CE) activities in support of the COS application?

1. Beginning in 2015, Algoma Power augmented their annual telephone based Customer Satisfaction survey with supplemental questions to help gain insights into, or deal with, issues customers care about. For example, the 2018 telephone survey of 401 Algoma Power customers were asked to prioritize 12 items which can affect costs. (See Insights from annual telephone-based Customer surveys 2015-2018)
2. Algoma Power embraced the Taking A.I.M. process (Applied Insights Methodology) to gather information and feedback from multiple sources. A process which gives customers multiple opportunities to "make their voice count." (See What is Taking A.I.M.)
3. Through a joint on-site review, sixty-eight (68) CE activities were identified as customer interactive touchpoints which could provide information for the Cost of Service (COS) application. (See Insights from a review of Algoma Power's Customer Engagement Activities)
4. There were 192 questions contained in the seven (7) online Taking A.I.M. Chapter Surveys designed to capture each survey respondent's information, insights, wisdom, and feedback. It is important to note, getting participation in "long" online surveys is an onerous challenge. The strategy of using 7 online chapter surveys is to break down the complexity of the subject into manageable amounts. (See Insights from the Online Book of Surveys for Algoma Power's Cost of Service Application)
5. 264 customer respondents participated in one or more of the seven chapters available to them. 108 of the respondents completed all 7-chapter surveys. Chapter survey #7, which contains the most DSP type of information had 195 participants.
6. 121 "Wisdom from Customer" comments were made (See Wisdom from Customers)
7. 82 "General comments" about the COS application were made (See General Comments)
8. Customer respondents to the online chapter surveys were given 6 opportunities to request an Algoma Power professional contact them because they had a specific question or issue they wanted addressed. 17 customer respondents asked for follow up.
9. Customer respondents were given 6 opportunities to request to be contacted when public meetings associated with the COS rate application were scheduled. There were 22 requests.
10. Algoma Power used its resources to reach out to its customer base publicly.

The findings in this report show Algoma Power is a well-respected company, who is trusted and trustworthy and who is seen as an organization which spends money prudently. More importantly, 73% of customer respondents are “very + somewhat” confident the professionals at Algoma Power will use good judgment for prioritizing capital investments. The data from the online surveys also show the majority of respondents support Algoma Power’s recommendations as they relate to System Renewal, System Service, General Plant, and Vegetation Management investments.

The customer base is a rural one. As such, it is more tolerant of the number of outages, although that doesn’t mean Algoma Power can lessen its standard of reliability. 88% of respondents, agree API’s current standard of reliability meets their requirements.

Comments received through this Taking A.I.M. process indicate a concern about high “delivery charges.” 60% of chapter survey #7 respondents thought the amount of the bill given to Algoma Power for its responsibilities was ‘very + somewhat reasonable.’ 19% were ‘somewhat + definitely unreasonable.’ These delivery charges can upset Seasonal customers. A comment from a customer respondent: *“Don't agree with my seasonal residence costs are higher than a non-seasonal place next door to mine.”*

Access to the internet for this customer base is not at the same level as many urban areas, which contributes to the higher propensity to prefer telephone contact. Poor access to the internet means the return on investment of various technological advances, especially as they relate to customer care, will need a longer period to recoup the investment.

The customer base does look at changes through the lens of costs and therefore has a deep desire to keep costs low. However, they also expect high standards of operations. Data from 4 years of telephone surveys tells us the number one suggestion for improvement is “reduce the price.” When it came to items dealing with performance in the Taking A.I.M. surveys, customer respondents were more apt to under-rate Algoma Power’s performance. Likewise, with questions addressing costs of services or investments, respondents were more likely to under-estimate what things costs. The reality is, LDC customers in Algoma Power territory, and throughout Ontario, know a glass of orange juice at $16 is over-priced. Wrapping their heads around whether a 2.3 million dollar system renewal budget is right however, is not easy. As a customer respondent commented: *“Unfortunately this is not my area of knowledge I leave it in your capable hands.”*

A comment from a Chapter Survey respondent captures the sentiment of many: *“Personally, I feel Algoma Power is a pretty good company. I like the safety procedures and training I see among your emergency employees who should be getting paid more than any office worker. Of course, I want better service at lower costs, but I know that it is not possible. I think real deep-down, conservation education is our only hope, with carrots as incentives, to improve efficiency, not penalties.”*

Our recommendations are:

1- Continue to take a thoughtful approach to capital investments. While keeping them essentially in line with inflation would be supported by the majority of customers, there will be a core of customers who will be unhappy with everything.

2- Increases above inflation levels could be supported by the customer base for selective items. For example, 70% of online respondents supported paying more for an outage notification system that automatically sends a message by phone call, email or text when there is an outage.

3- Vegetation management can spark debate. The customer base understands the importance of continuing with the current 6-8 year cycle. There may, however, be opportunities to improve communication.

4- A constant and steady diet of customer engagement activities will help identify opportunities for improvement, and keep the organization's excellent reputation as a company who: 'Deals professionally with customers' problems', is 'Customer-focused and treats customers as if they're valued,' and 'Is a company that is 'easy to do business with'.

5- Algoma Power's customers will have a slower adoption rate of technological services in comparison to many other LDCs in Ontario (due to the quality of internet access in Algoma Power's territory). The added time will impact R.O.I.

6- There are many factors to be considered when talking about retro-fitting or building facilities. To ensure support, a facilities plan needs to accentuate safety, security, protection of equipment, labour efficiency. Operational pragmatism is the key.

7- Keep in mind, every touchpoint – in person, and online is an opportunity to re-enforce the viewpoint Algoma Power is customer-focused and values its customers.

8- Maintain the image of Algoma Power as a high-quality company by communicating frequently, and ensuring everyone at API re-enforces the "brand."

There are two things which stand out in this assignment. First of all, the leadership of Algoma Power had the courage to ask questions about how the leadership was perceived, e.g., how confident survey respondents were in the leadership to use good judgment. Second, the open-minded nature of the leadership team to ask questions, about sensitive topics such as: connects and disconnects, access to front-counter staff, and arrears management. Included in the questions about those sensitive topics were the associated “costs.” Understanding often means asking questions about sensitive topics.

Seeking to understand is not the same as seeking permission. Algoma Power’s customers may not know a lot about the electricity industry or what Algoma Power as a company is responsible for, but they do know the importance of electricity in their lives. The leadership of Algoma Power understands, one of the best ways to ensure costs remain low, is to discover ways to be more successful today while preparing the organization to be successful again tomorrow in a changing industry, and in a changing world. Seeking wisdom, information, insight, and feedback from its customers certainly help to ensure the future path of the organization meets the needs and wants of its customers. Algoma Power, as a small LDC, has undertaken many customer engagement activities to understand their customers’ concerns and priorities.

By demonstrating that the COS rate application is built by people who are pragmatic, thoughtful and informed, we believe Algoma Power will gain the support of the majority of its customers. The results make evident customers have confidence in the people at Algoma Power. When asked about whether a customer respondent had any additional comments about Algoma Power or its COS application, one respondent provides guidance by simply stating: *“Can't think of anything, but priority is reliable service, communication with customers, restoration of service.”*

Customers want lower prices with better service – despite knowing equipment wears out or fails and must be replaced. Algoma Power shouldn’t expect to get agreement from all of its customers regarding the COS rate application. But Algoma Power will get support for what needs to be done because leadership can demonstrate they understand their customers – their needs, wants and standards.

Sid Ridgley
UtilityPULSE
February 2019

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⁕ Insights from a Review of Algoma Power's Customer Engagement Activities

As the first step in the TAKING A.I.M. (Applied Insights Methodology) process, UtilityPULSE conducted an onsite review of Algoma Power's Customer Engagement (CE) activities. The review identified sixty-eight (68) CE activities as customer interactive touchpoints which were sorted into the various levels of customer engagement: ❶Informing & information gathering, ❷Gathering feedback, ❸Capturing insights, ❹Gaining wisdom and ❺Customer empowerment.

Based on our experience, for a small LDC Algoma Power has an extensive list of CE activities, and showed an enthusiasm for doing more. For example, we do not know of another Ontario LDC with less than 12,000 customers who conduct an extensive Annual Customer Satisfaction survey through a 3rd party. To our knowledge, LDCs with this level of customers conduct their survey on a bi-annual basis in order to meet OEB requirements only.

Conclusions based on the review of CE activities for the COS/DSP submission:

1- Website reformatting would be required to host Taking A.I.M. online surveys
2- Marketing, i.e., inviting customers to provide opinion and comment, could start with printing a message on the back of the bill envelopes, this started in July 2018
3- IVR technology would be used to encourage customers to participate
4- Additional face-to-face type community outreach activities would add to application data
5- Online surveys could and should include costs in $$ when and where practical, e.g., the costs of connects/disconnects
6- Online surveys should make good use of descriptor statements to gauge support for a policy or operational changes, e.g., Access to front-counter staff
7- The Fall 2018 Telephone survey would incorporate enhanced supplemental questions to:
    a. Determine Algoma Power's communication effectiveness
    b. Gauge how customers rate their access to Algoma Power's services
    c. Gain a better understanding of customers' priorities and expectations
8- "Wisdom from Customers" would be a feature of the online surveys thereby giving respondents the opportunity to provide ideas which could save money or reduce costs
9- A "Hot Alert" function would also be a feature of the online surveys thereby giving respondents the opportunity to be contacted by the LDC for a specific issue and/or be kept apprised of any public meetings associated with the COS/DSP application
10- Algoma Power and UtilityPULSE could continue to provide suggestions for enhancing existing practices.

❋ Insights from the Book of Online Surveys for Algoma Power's Cost of Service Application

About the respondents:

1- 264 unique respondents, many of whom, completed more than one Chapter Survey
2- The range of participation was a low of 117 in Chapters 5 & 6, to a high of 195 in Chapter 7
3- Respondents answered a set of preliminary identifying/demographic questions. [See Appendix A: Book of Online Surveys – Chapter 8 - "About You" questions]
   Here respondents identified their:
   a. Postal code
   b. Residential or Commercial customer status
   c. Responsibility level for paying the bill
   d. Identify the average amount of their bill.
4- Respondents also answered a set of closing questions giving respondents the opportunity to be contacted by the LDC for a specific issue and/or be kept apprised of any public meetings associated with the COS/DSP application. [See Appendix A: Book of Online Surveys – Chapter 9 - "Hot Alert" questions]
5- Chapter surveys were made available in staggered dates beginning June 29, 2018. All seven Chapter surveys were available until January 31, 2019.

Chapter Surveys:

Chapter 1 "About your Algoma Power"

Chapter 2 "How the electricity industry works and Algoma Power's role in it"

Chapter 3 "Help Algoma Power understand our customer's priorities"

Chapter 4 "Getting customer insights about billing and outages"

Chapter 5 "Help us prioritize capital investments in the electricity network"

Chapter 6 "Gathering insights about customer care operations"

Chapter 7 "Help us determine which capital investments and operational changes you can support"

Chapter 1 "About your Algoma Power"

Purpose of this Chapter:

1- To gather feedback about Algoma Power's purpose and values
2- To help current and potential participants for additional chapters/surveys gain a better understanding of Algoma Power as a company
3- To gauge the level of respondent disposition, i.e., positive or negative, towards Algoma Power as a company
4- To demonstrate Algoma Power's desire to solicit feedback.

Topics:

- Purpose & Values
- Governance
- Standards

Primary theme(s):

Algoma Power's Purpose and Values:

Algoma Power Our Purpose and Values

Algoma Power Inc. has employees working across the Algoma District from Wawa to Thessalon including supervisory, clerical and technical positions, representing a wide-range of skills and a constant commitment to meet our customers' needs and creating, 'powerful connections.' We also have a long and proud history of electricity distribution and service to customers in this area for over 100 years.

Our Purpose:

"At Algoma Power our purpose is to efficiently distribute safe, high-quality, reliable electricity in an environmentally sound manner at reasonable rates with high-quality customer care."

Our Values

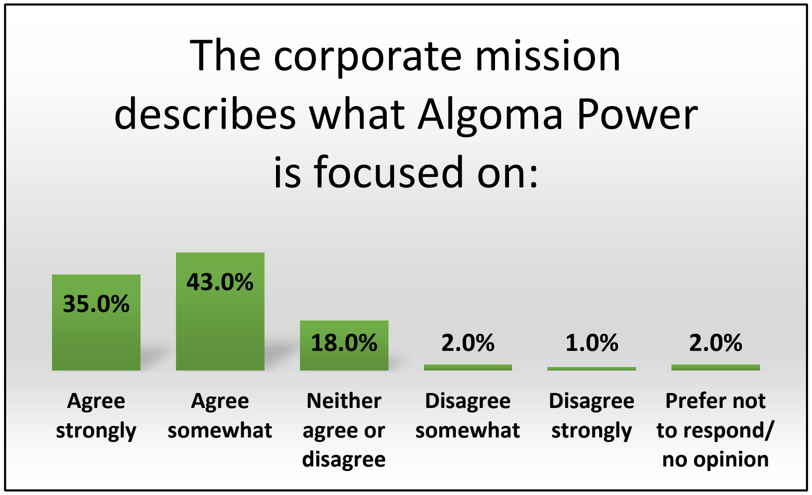
Algoma Power has embraced six core values that all employees should strive to emulate each working day. To be effective, these values must be understood, communicated, reinforced and integrated into all our daily activities. The six core values include:

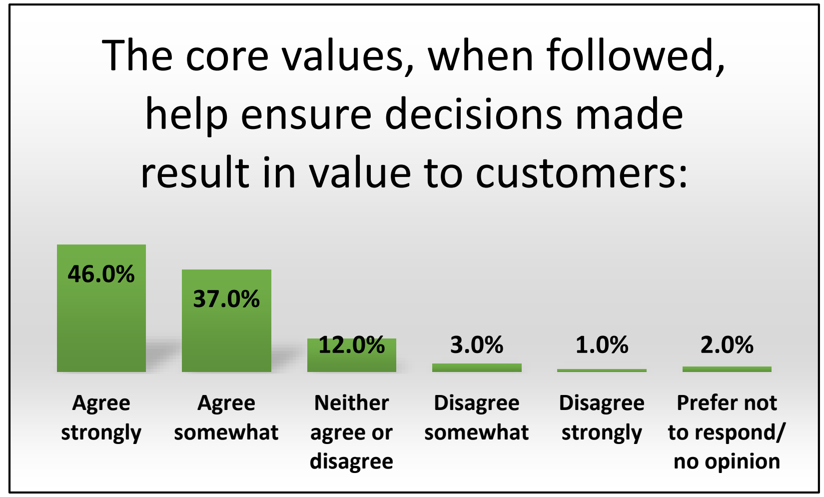
- **Respect For People** - Treat others, as you would have others treat you. Honesty, integrity and ethics are never compromised.
- **Safety and the Environment** - Demonstrate a personal, unrelenting commitment to safety and environmental excellence. Protect yourself, your fellow employees, the public and our environment.
- **Financial Success** - Produce solid earnings, with dividends that meet the expectations of shareholders. Grow shareholder value through prudent equity investments and business partnerships. Ensure that debt obligations are always met in a timely manner and to the satisfaction of our creditors.
- **Customer Service** - Everyone has customers. Determine your customer's needs by listening. When you can meet these needs; do so. When you cannot, tell them that you cannot; or tell them who can. When in doubt about how to treat a customer, do what you believe is right. When serving customers, be pleasant, courteous and accurate; smile, act professionally and enjoy yourself. Attitudes are contagious.
- **Productivity** - The old sayings hold true. Teamwork is key. Working smarter produces more gains than working harder. Mistakes are costly; get it right the first time. Job security comes from doing your job well, not from what job you do. Remember…if you have a better way to do something; just do it.
- **Community Involvement** - Each of us has an obligation to support the communities that support us. This means time as much as money. Success is measured by the reaction of community leaders and the opinions expressed by community residents.

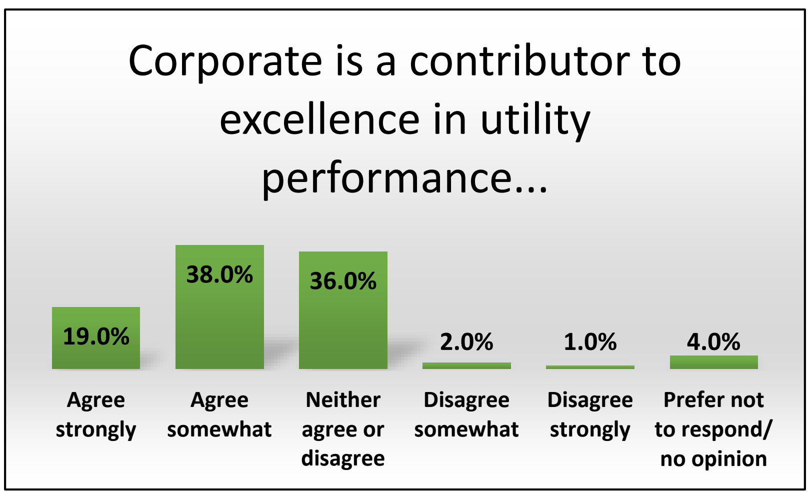
Insights. Findings. Feedback.

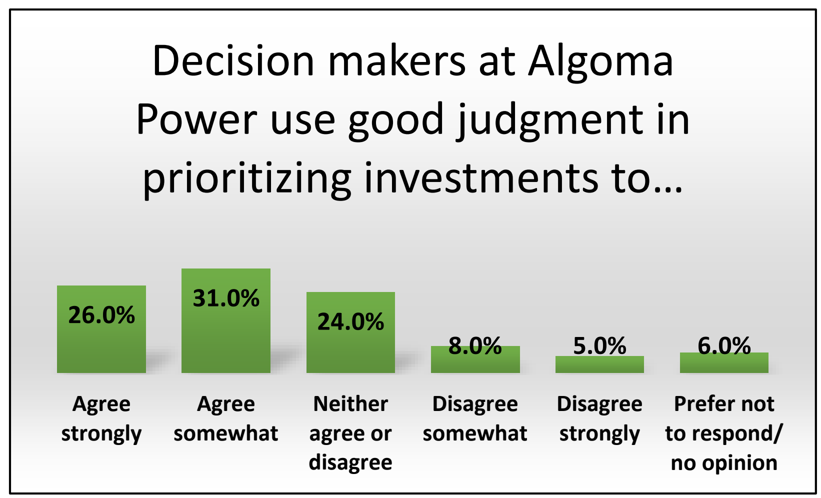
Respondents of this chapter survey are quite supportive of Algoma Power as a company. This survey also utilized a cross-over technique to compare online results with telephone survey results. There is tremendous consistency between the two methods.

Base: total respondents, 2018 online survey









To what degree do you agree or disagree with the following attributes:					
Algoma Power	**Online 2018**	**Telephone 2018**	**Telephone 2017**	**Telephone 2016**	**Telephone 2015**
Algoma Power provides consistent, reliable electricity.	89%	89%	87%	85%	88%
Overall, Algoma Power provides excellent quality services	88%	86%	87%	86%	86%
Is a company that you would like to continue to do business with.	86%	87%	86%	80%	78%
Is a trusted and trustworthy company	86%	84%	88%	81%	83%
Spends money prudently to keep the electricity system reliable and up-to-date	77%	83%	81%	76%	77%
The frequency of communications from Algoma Power meets my needs	86%	--	--	--	--

Base: total respondents with an opinion: 2018 online survey and 2015-2018 telephone surveys

Chapter 2 "How the electricity industry works and Algoma Power's role in it"

Purpose of this Chapter:

1- To help educate respondents about how the electricity system works in Ontario
2- To provide knowledge as to the role and responsibility of Algoma Power in the electricity sector
3- To gauge the level of awareness or understanding about various aspects of Algoma Power’s operations
4- To provide respondents with an interactive experience, wherein they would receive a “score” at the end of the survey. Respondents are presented with 11 multiple choice questions. Upon completion of the survey, customers receive a “score” along with a summary of their response choices and the correct answers. This process creates a double imprint and thereby improves the learning value from answering the questions. [See Appendix A Chapter survey #2 for the questions and a sample of the “score”]

Topics:

- About the electricity system
- How much $ does the LDC get
- How many $ are invested
- Responsibilities of the LDC

Primary theme:

Insights. Findings. Feedback.

Not surprising, 84% of respondents had a total score of 50% or less. Knowing that the level of electricity industry and LDC knowledge is low means questions in future chapter surveys need to be shaped, where possible, to re-enforce the role, responsibilities, and scope of Algoma Power’s operations.

Respondents typically selected answers which were lower than actual Algoma Power investments or costs when $$$ was involved.

45% of respondents picked a higher power interruption number than the 3.16 actual. 60% picked lowed cost numbers than the $4.9 mil for vegetation management and, 69% of respondents picked lower investment numbers for the distribution infrastructure than the actual $5.3 mil. Essentially respondents over-estimate problems and under-estimate costs.

	Correct Answer	% selecting the correct answer
Scope of Operations		
How many customers does Algoma Power serve?	**11,700**	46%
The size of territory covered by Algoma Power is?	**14,200 sq. km**	58%
How many kilometers of overhead lines and underground lines does Algoma Power manage?	**1,850 km**	37%
For the average residential customer, approximately what percentage of the bill goes to Algoma Power?	**25%**	23%
Which organization must approve every item shown and charged on your electricity bill?	**OEB**	63%

TEST YOUR KNOWLEDGE

	Correct Answer	% selecting the correct answer
<u>Reliability and Replacing Infrastructure</u>		
What would be the average number of times power to customers is interrupted? (last 3-year average)	**3.16**	33%
Trees and branches falling on power lines cause about 35% of all outages. Algoma Power has an established 6-8 year cycle for dealing with trees and brush around power lines. Based on the last 3 years, how much has been invested annually to reduce outages and fires from branches and brush touching powerlines?	**$4.9 mil**	16%
Keeping the electricity distribution infrastructure, known as the “Grid,” operating efficiently requires adding or replacing equipment such as poles, wire, cables, transformers, substations, etc. Based on the last 3 years, what was Algoma Power’s annual capital investment plan in the “Grid” with the goal of maintaining and/or improving safety, meeting customer or community needs, power quality, and reliability?	**$5.3 mil**	15%

TEST YOUR KNOWLEDGE

	Correct Answer	% selecting the correct answer
Customer focus		
Algoma Power's billing accuracy is	**99.48%**	44%
In Algoma Power's most recent telephone survey conducted by UtilityPULSE, what percent of respondents said they were somewhat or very satisfied with Algoma Power?	**88%**	28%
Being efficient in meeting day-to-day business and operational needs is a high priority for Algoma Power. Based on the last 3 years, what was Algoma Power's annual capital investment in having the right tools & equipment, good trucks, computers and software to help quickly deal with things such as outages, equipment failures, billing, and security?	**$1.0 mil**	19%

Score 0-25

23%

31 respondents

Score 26-50

61%

82 respondents

Score 51-75

16 %

21 respondents

35%

Base: total respondents, 2018 online survey - Chapter 2:134 respondents

Chapter 3 "Help Algoma Power understand our customer's priorities"

Purpose of this Chapter:

1- To learn more about how respondents feel about Algoma Power
2- To review various policies which affect costs and services to customers
3- To determine the level of support for various standards
4- To gather input from respondents about the priority level of various items which affect costs
5- To determine how satisfied respondents are with the convenience levels associated with accessing services

Topics:

- Company attributes
- Managing expectations while managing costs
- Policy review regarding topics which affect costs to customers
- Convenience of accessing services

Primary theme(s):

Insights. Findings. Feedback.

There is a tremendous amount of consistency between respondents' feedback received via Fall 2018 telephone interviews and those received via online chapter surveys. UtilityPULSE utilizes, and tracks, 25+ attributes (factors important to customers) when generating an enterprise-wide measurement known as the UtilityPULSE report-card. Chapter 3 online survey incorporated 9 of those attributes. The responses received reveal respondents hold Algoma Power in high esteem.

To what degree do you agree or disagree with the following attributes:					
Algoma Power	**Online 2018**	**Telephone 2018**	**Telephone 2017**	**Telephone 2016**	**Telephone 2015**
Deals professionally with customers' problems	90%	85%	85%	82%	84%
Customer-focused and treats customers as if they're valued	88%	81%	83%	80%	81%
Quickly deals with issues that affect customers	89%	85%	86%	85%	82%
Is a company that is 'easy to do business with'	88%	87%	85%	77%	83%
Makes electricity safety a top priority for employees and contractors	91%	89%	89%	84%	88%
Delivers on its service commitments to customers	87%	86%	88%	86%	86%
Overall Algoma Power provides excellent quality services	90%	86%	87%	86%	86%
Keeps its promises to customers and the community	86%	83%	80%	75%	85%

Base: total respondents with an opinion: 2018 online survey and 2015-2018 telephone surveys

Holding Algoma Power in high esteem is important as it will mean more support whenever the utility would like to make some changes. Level of esteem for the company, however, doesn't play a role in what customers think about assigning priority levels to a number of items which affect reliability, safety, environment or costs.

The top 3 priorities for Algoma Power (as shown in the chart below) are consistent with findings from other related UtilityPULSE LDC surveys. Priority levels for the additional 10 items are affected by the "self-interest" level the person has in the item.

Meeting expectations while managing costs begins with understanding Customer priorities.

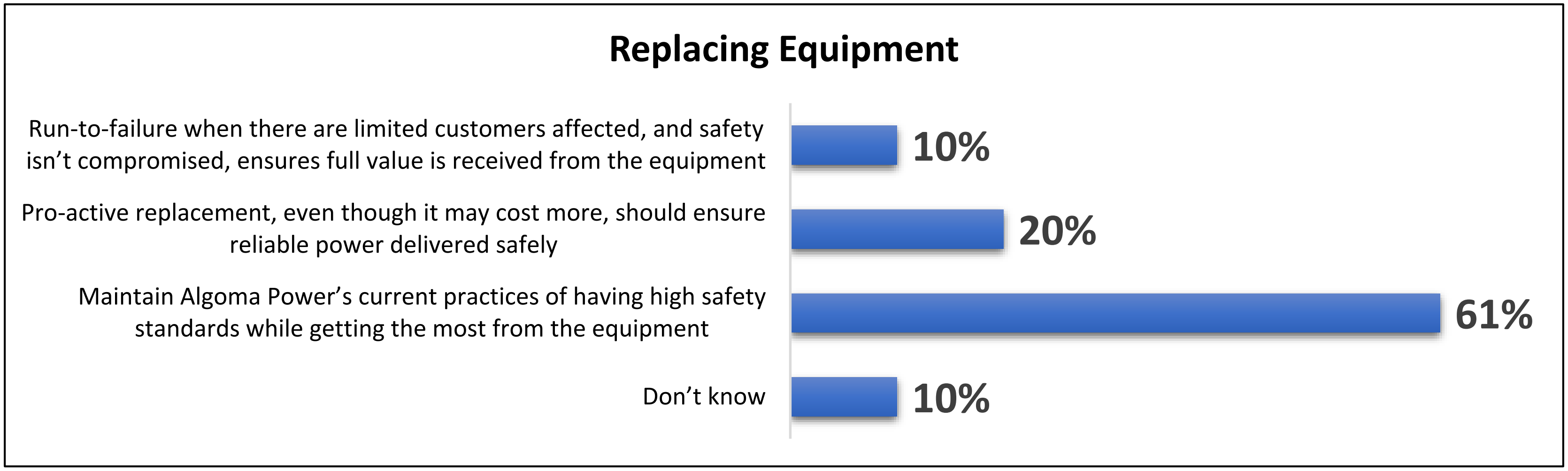
As you look toward the next 5 years, could you assign a priority level to each of the following items?			
Algoma Power	**Online 2018**	**Telephone 2018**	**UtilityPULSE 2018**
Maintaining and upgrading equipment	86%	87%	89%
Reducing response times to outages	80%	79%	83%
Investing more in the electricity grid to reduce outages	76%	76%	80%
Investing more in vegetation management (clearing trees and brush around powerlines)	57%	75%	74%
Investing in projects to reduce the environmental impact of Algoma Power's operations	65%	69%	74%
Educating the public as it relates to electricity safety	51%	68%	71%
Educating customers about energy conservation	57%	64%	68%
Burying overhead wires	43%	51%	60%
Providing sponsorships to local community causes	36%	49%	48%
Developing a smartphone application to allow you to view your electricity use and pay your bill	32%	36%	46%
Providing more self-serve services on the website	32%	22%	37%
Making better use of social media (such as twitter, facebook, and others)	21%	20%	26%
Educating customers regarding how Algoma Power's operations run	36%	--	--

Base: total respondents: Top 2 box 'Very high + High Priority'; UtilityPULSE database 1204 telephone interviews Fall 2018

Policy review and considerations:

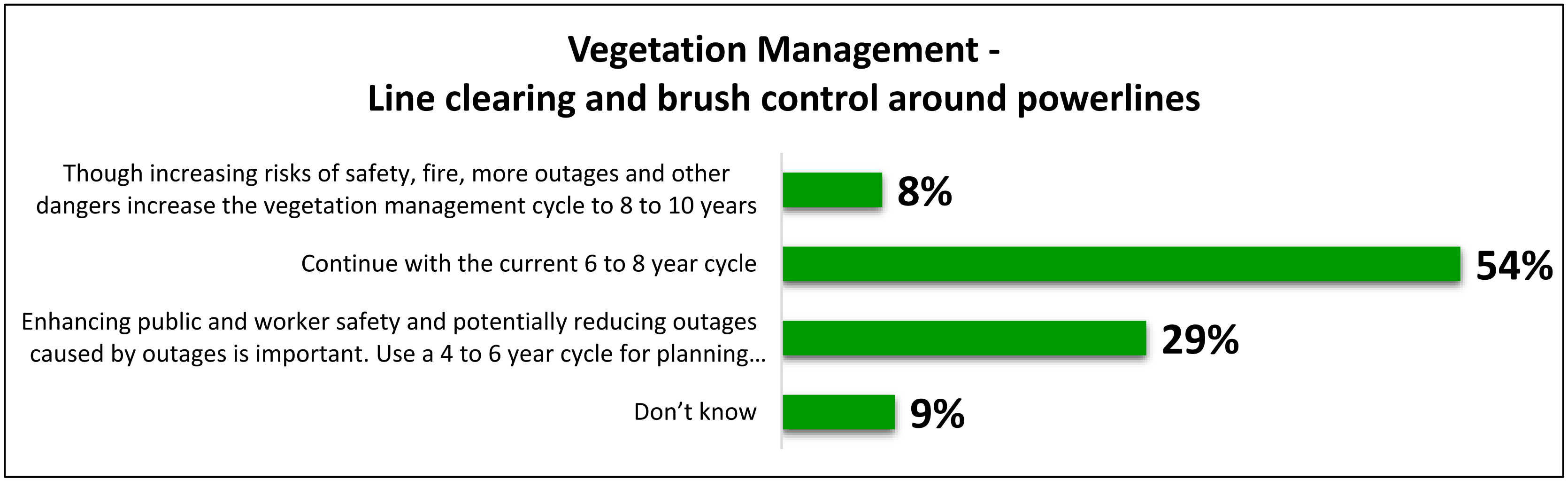
Full text of each question is available in Appendix A, Chapter survey #3

As it relates to replacing equipment at Algoma Power, which of the following statements is closest to your viewpoint?



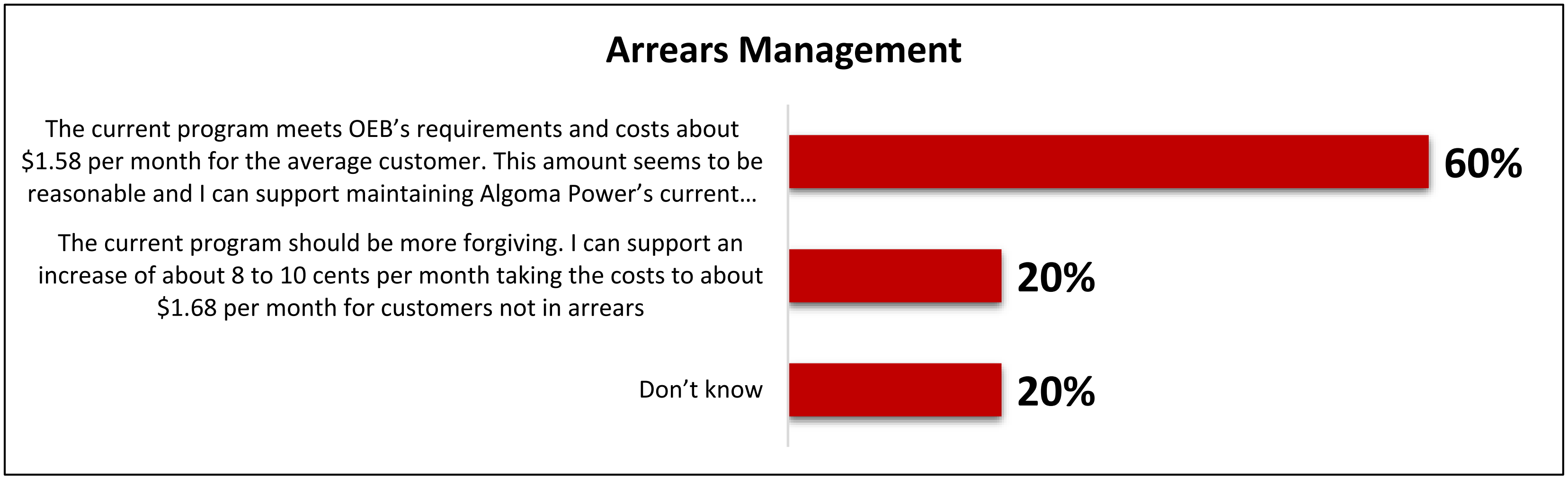
Base: total respondents, 2018 online survey

As it relates to vegetation management, which of the following statements is closest to your viewpoint?



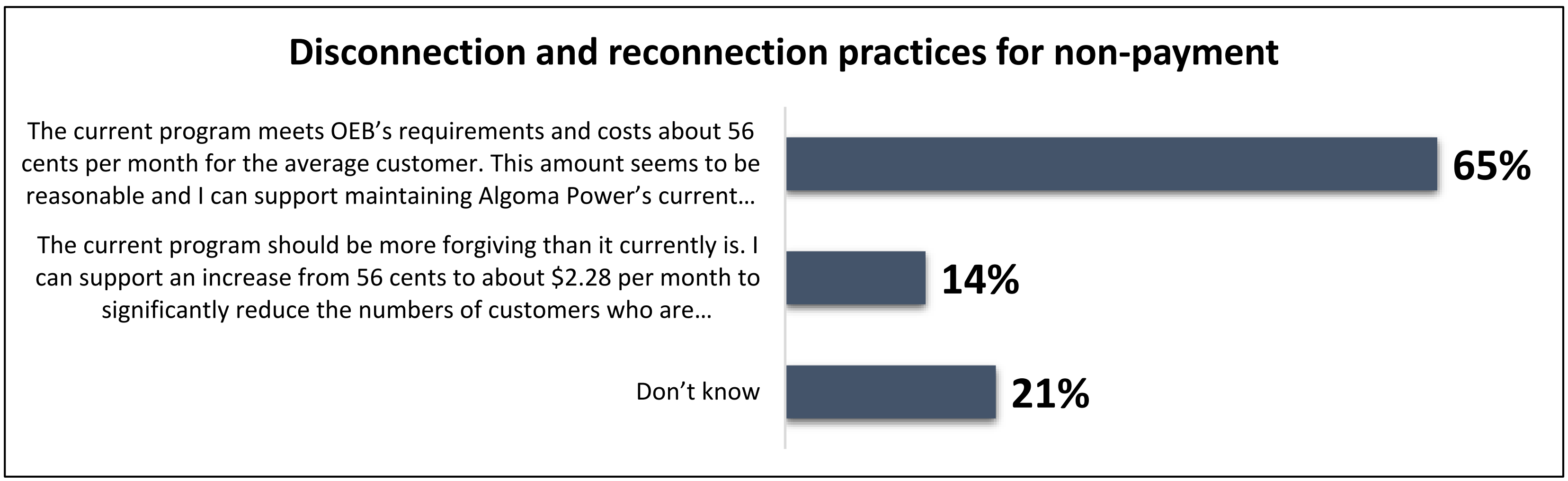
Base: total respondents, 2018 online survey

As it relates to arrears management, which of the following statements is closest to your viewpoint?



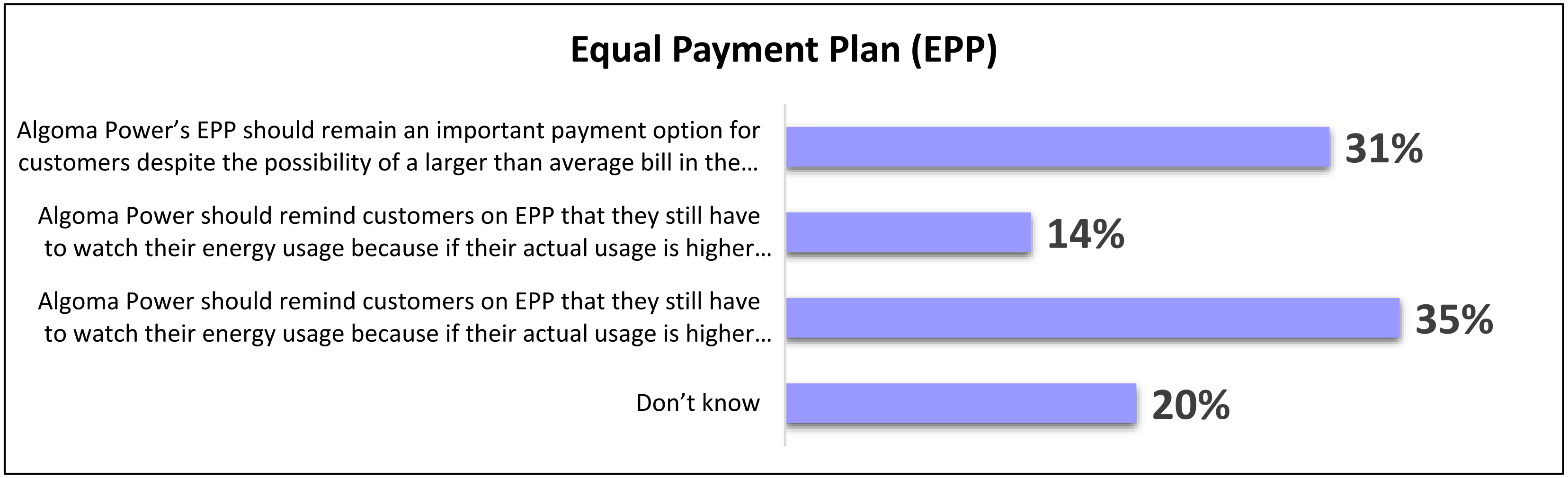
Base: total respondents, 2018 online survey

As it relates to disconnection and reconnection practices, which of the following statements is closest to your viewpoint?



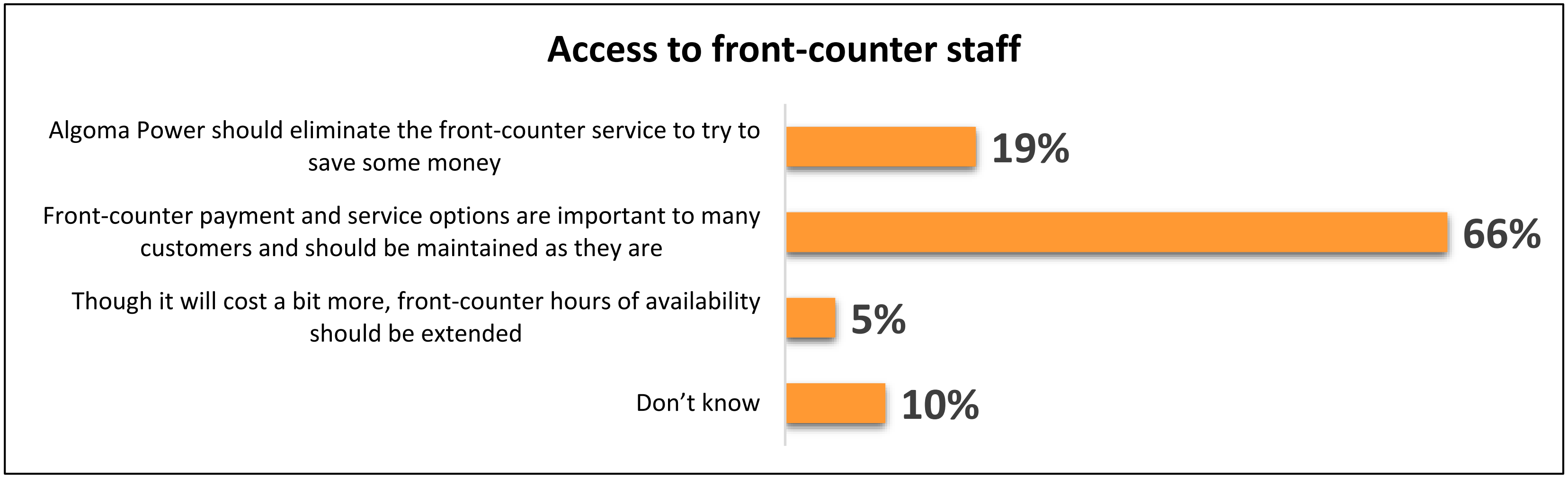
Base: total respondents, 2018 online survey

As it relates to the Equal Payment Plan, which of the following statements is closest to your viewpoint?



Base: total respondents, 2018 online survey

As it relates to access to front-counter staff, which of the following statements is closest to your viewpoint?

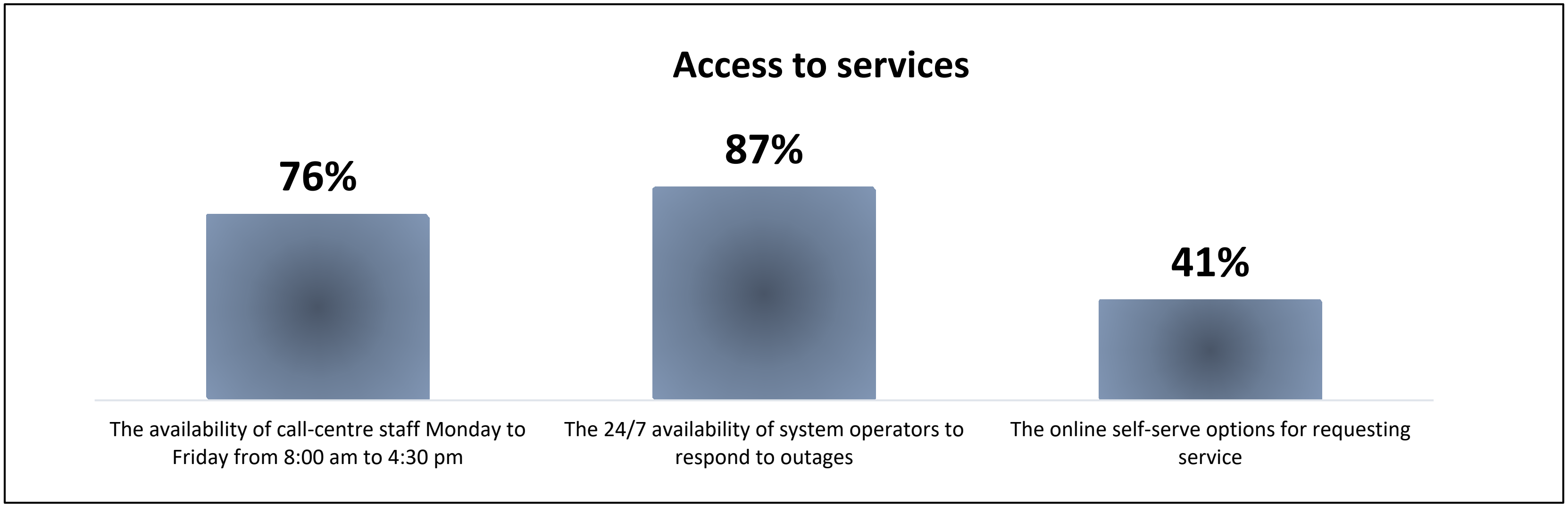


Base: total respondents, 2018 online survey

As it relates to the convenience of accessing services, for each of the following topics how satisfied are you…

Access to services			
Algoma Power	**Online 2018**	**Telephone 2018**	**UtilityPULSE 2018**
The availability of call-centre staff Monday to Friday from 8:00 am to 4:30 pm	76%	81%	76%
The 24/7 availability of system operators to respond to outages	87%	80%	77%
The online self-serve options for requesting service	41%	45%	56%
The online self-serve options for managing your account	--	52%	63%

Base: total respondents: Top 2 box 'Very Satisfied + Fairly Satisfied'; UtilityPULSE database 6,207 telephone interviews Fall 2018



Base: total respondents, 2018 online survey

Chapter 4 "Getting customer insights about billing and outages"

Purpose of this Chapter:

1- To determine to what degree customer respondents perceive Algoma Power, as it relates to providing consistent, reliable electricity and handling outages
2- To determine to what degree customer respondents perceive Algoma Power, as it relates to accurately billing its customers
3- To learn more about the preferred method(s) for contacting Algoma Power when there is a billing issue or an outage
4- To gather feedback regarding various subjects such as e-billing
5- To solicit information about the impact of outages
6- To identify customer respondent's preference, going forward, for improving reliability
7- To gain insight into how much customer respondents might be willing to pay for a higher standard of reliability
8- To understand customer respondent's expectation as it relates to outbound messaging regarding outages

Topics:

- Billing
- Outages
- Standard of reliability
- Communications

Primary theme(s):

Insights. Findings. Feedback.

Blackout (outages) and billing problems, we call them the “Killer B’s,” the two issues most likely to cause grief to utility customers. Ensuring power reliability has and will continue to be the key operational priority for electric utilities.

Bills and blackouts are a major component of the annual customer satisfaction survey, as such, there is a tremendous amount of comparison data available.

Our 20+ years of research tells us, the perception of LDC competency and value are linked to the frequency and duration of power outages. 88% of online respondents and 90% of telephone respondents with an opinion agree Algoma Power “quickly handles outages and restores power,” and 89% online 88% telephone respondents agree Algoma Power “has a standard of reliability that meets expectations.”

To what degree do you agree or disagree with the following attributes:					
Algoma Power	**Online 2018**	**Telephone 2018**	**Telephone 2017**	**Telephone 2016**	**Telephone 2015**
Algoma Power provides consistent, reliable electricity.	91%	89%	87%	85%	88%
Accurately bills its customers	87%	87%	86%	78%	86%
Has a standard of reliability delivering electricity that meets your expectations	89%	88%	88%	84%	84%
Quickly handles outages and restores power	88%	90%	85%	89%	88%
Makes electricity safety a top priority for employees and contractors	91%	89%	89%	84%	88%

Base: total respondents with an opinion, 2018 online survey, and 2015-2018 telephone surveys

Bills

It is important to note; customers perceive billing problems much differently than administration. Typically, an LDC views billing problems as a processing issue. Customers, however, view “high bills” as a billing problem. The chart below contains data from the recent online survey and Algoma Power’s telephone survey. For the last 10 years, respondents to the UtilityPULSE Ontario benchmark survey have consistently had higher incidents of billing problems than found in the UtilityPULSE National benchmark survey.

38% of online customer respondents and 67% of telephone respondents claimed their billing issue was ‘the bill was too high.’ Only 50% of online customer respondents and 50% of telephone respondents said they contacted Algoma Power about the issue with their bill.

Approximately 3 out of 4 respondents indicated their preference is to contact Algoma Power by telephone when there is an issue with their bill.

The 2016 spike in percentages of where respondents claimed they had a billing problem coincided with the period when Ontario LDC customers were most angry about the rates they were paying for electricity.

Percentage of Respondents indicating they had a Billing problem in the last 12 months

Algoma Power	Online 2018	Telephone 2018	Ontario Benchmark
2018	6%	9%	9%
2017	--	22%	15%
2016	--	37%	25%
2015	--	15%	15%

Base: total respondents, 2018 online survey and 2018 telephone survey, (--) online survey not conducted in that year
Ontario benchmark is based on telephone interviews of LDC paying customers located throughout the province of Ontario in Fall 2018

e-billing is an opportunity area for every LDC in Ontario, Algoma Power is no exception.

Take-up rates vary by such factors as urban-rural, economic status, access to high-speed internet and, age. Other than these aforementioned factors, respondents were asked to list their view on the top 3 barriers which get in the way of more customers moving to electronic billing.

Barriers for e-billing

In your view what are the top 3 barriers which get in the way of more customers moving to electronic billing?	Algoma Power Point Rankings
Some customers do not have access to the internet	200
Some customers are not comfortable with technology	173
Receiving the bill by mail is a reminder to pay	133
It is more convenient to receive the bill by mail	80
Security concerns about receiving electronic billing	64
Customers are not aware the cost savings of e-billing help offset future cost increases	64
Customers are unaware of the environmental benefit of e-billing	36

Base: total respondents, 2018 online survey

1

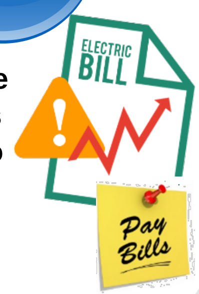
Some customers do not have access to the internet

2

Some customers are not comfortable with technology

3

Receiving the bill by mail is a reminder to pay



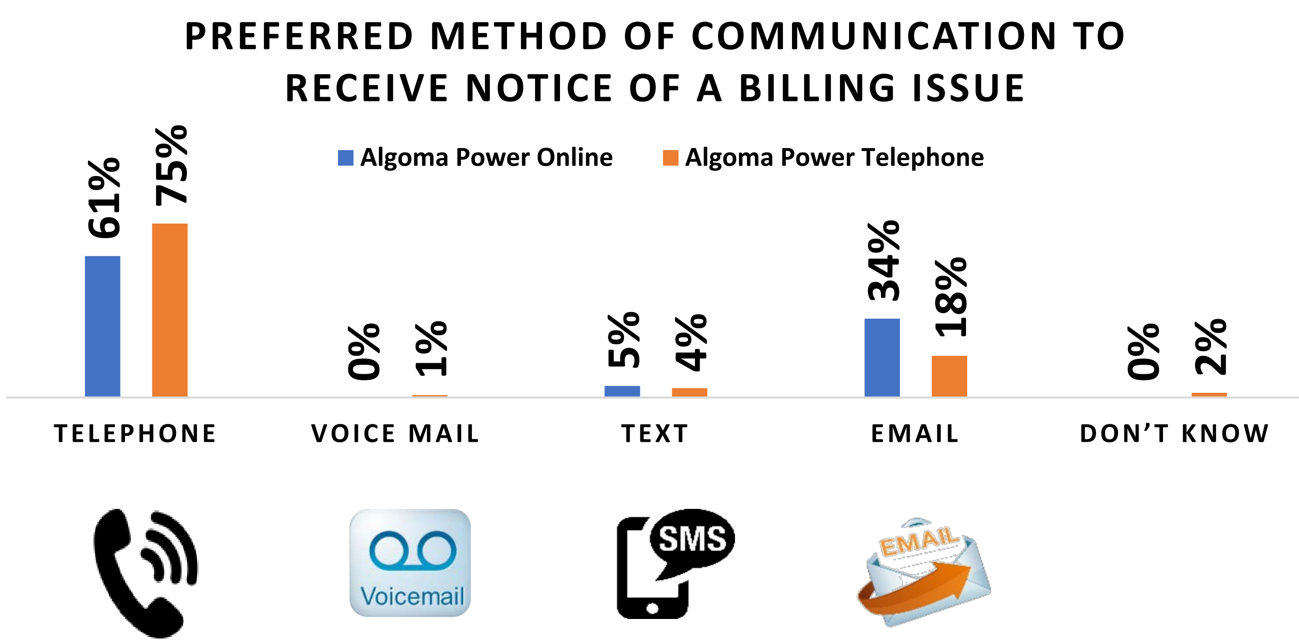
Recognizing customers have changing expectations; we included a question about the preferred method for Algoma Power to use to contact the customer when there is a billing issue, other than arrears. The adjacent chart includes data from the 2018 online survey, 2018 Algoma Power telephone survey and from the UtilityPULSE database based on 5,412 interviews with LDC bill payers during Fall 2018.

Preferred method of communication to receive notice of a billing issue

	Algoma Power Online	Algoma Power Telephone	UtilityPULSE Database
Telephone	61%	75%	56%
Voice Mail	0%	1%	2%
Text	5%	4%	7%
Email	34%	18%	34%
Don't know	0%	2%	1%

Base: total respondents, 2018 online survey and 2018 telephone survey,
(--) online survey not conducted in that year
UtilityPULSE database 5,412 telephone interviews Fall 2018

It is important to note, the difference between online and telephone respondents is because online respondents have access to the internet and are more comfortable with technology; as such we believe the telephone survey results are more indicative of the customer population for Algoma Power. However, 18% preference for email as found in the telephone survey is not a small number. We also know that with time the preference for email will increase.



Blackouts/Outages

Outages aggravate customers. It could be said, some outages anger customers. There will be outages – some will, of course, be weather-related. 90% of online respondents indicated they prefer to contact Algoma Power via telephone when there is an outage issue. This is a high number, but understandable given the geographic expanse of the utility.

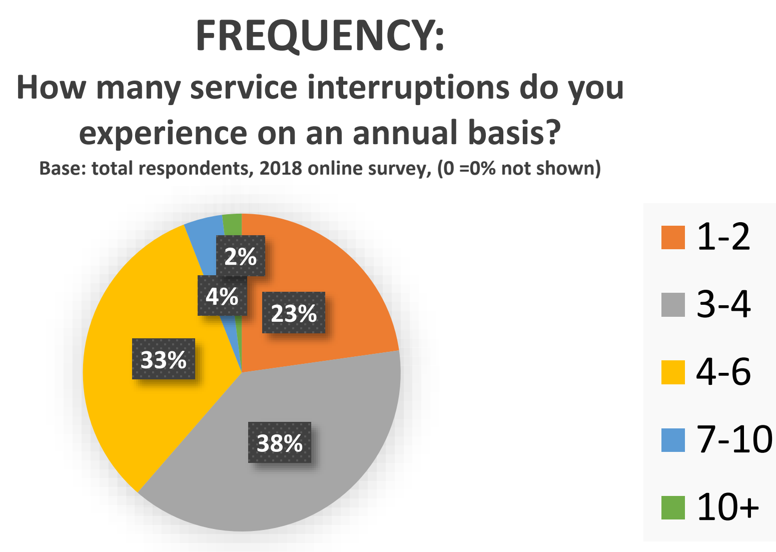
Percentage of Respondents indicating they had a Blackout or Outage problem in the last 12 months

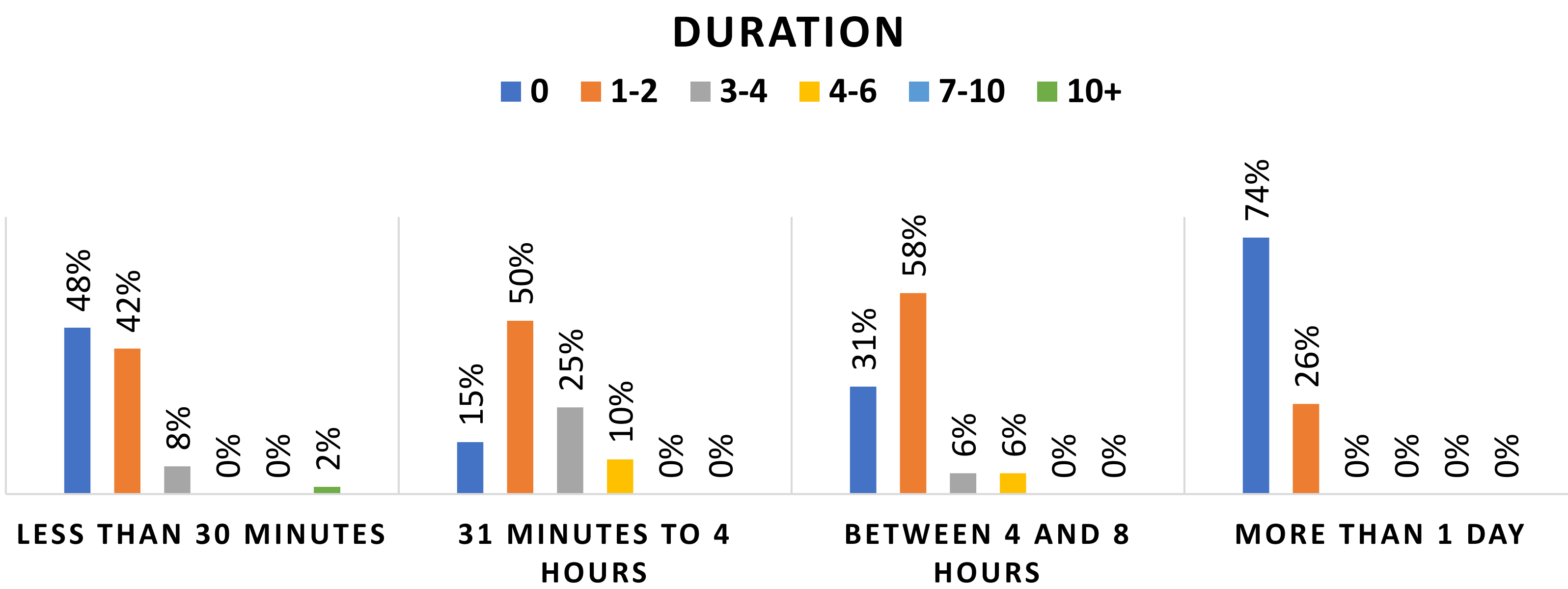
	Algoma Power Online	Algoma Power Telephone	Ontario Benchmark
2018	65%	57%	44%
2017	--	61%	38%
2016	--	45%	46%
2015	--	50%	51%

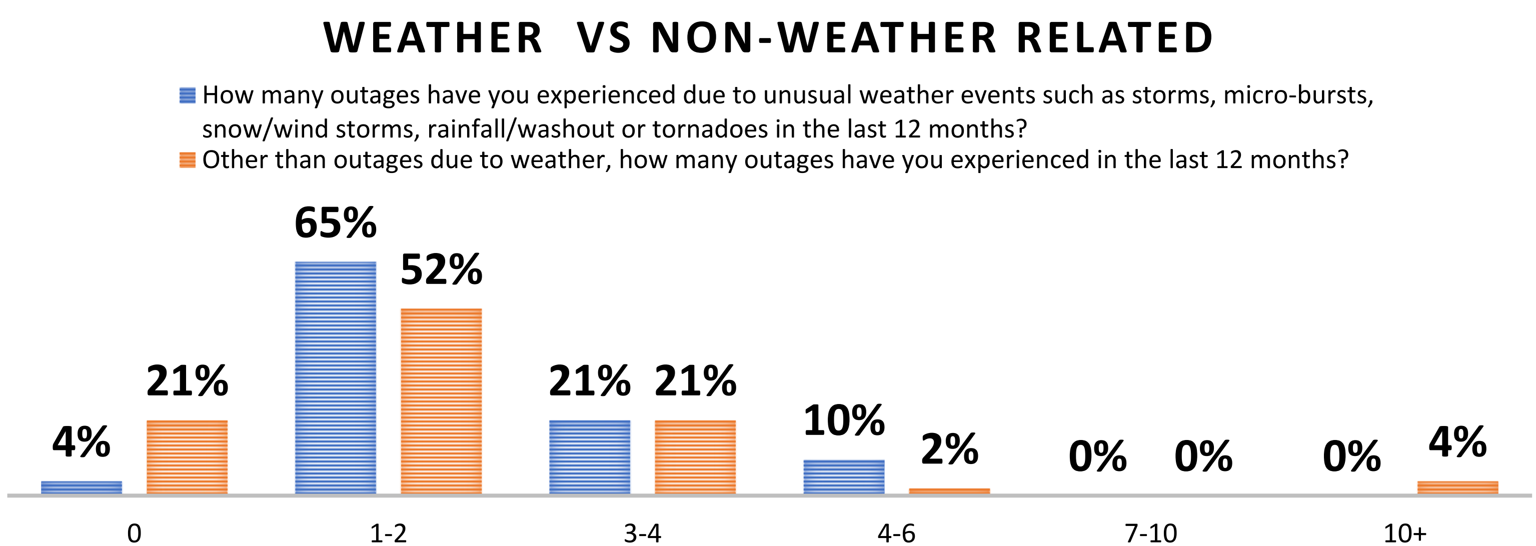
Base: total respondents, 2018 online survey and 2018 telephone survey, (--) online survey not conducted in that year
Ontario benchmark is based on telephone interviews of LDC paying customers located throughout the province of Ontario in Fall 2018

About the outages, findings from the online survey:

The data suggests customer respondents experience 3- 6 outages per year, of which, 2-3 are weather-related and 2-3 are not weather related.




DURATION
0
1-2
3-4
4-6
7-10
10+
48%
42%
8%
0%
0%
2%
15%
50%
25%
10%
0%
0%
31%
58%
6%
6%
0%
0%
74%
26%
0%
0%
0%
0%
LESS THAN 30 MINUTES
31 MINUTES TO 4 HOURS
BETWEEN 4 AND 8 HOURS
MORE THAN 1 DAY


WEATHER VS NON-WEATHER RELATED
How many outages have you experienced due to unusual weather events such as storms, micro-bursts, snow/wind storms, rainfall/washout or tornadoes in the last 12 months?
Other than outages due to weather, how many outages have you experienced in the last 12 months?
4%
21%
65%
52%
21%
21%
10%
2%
0%
0%
0%
4%
0
1-2
3-4
4-6
7-10
10+

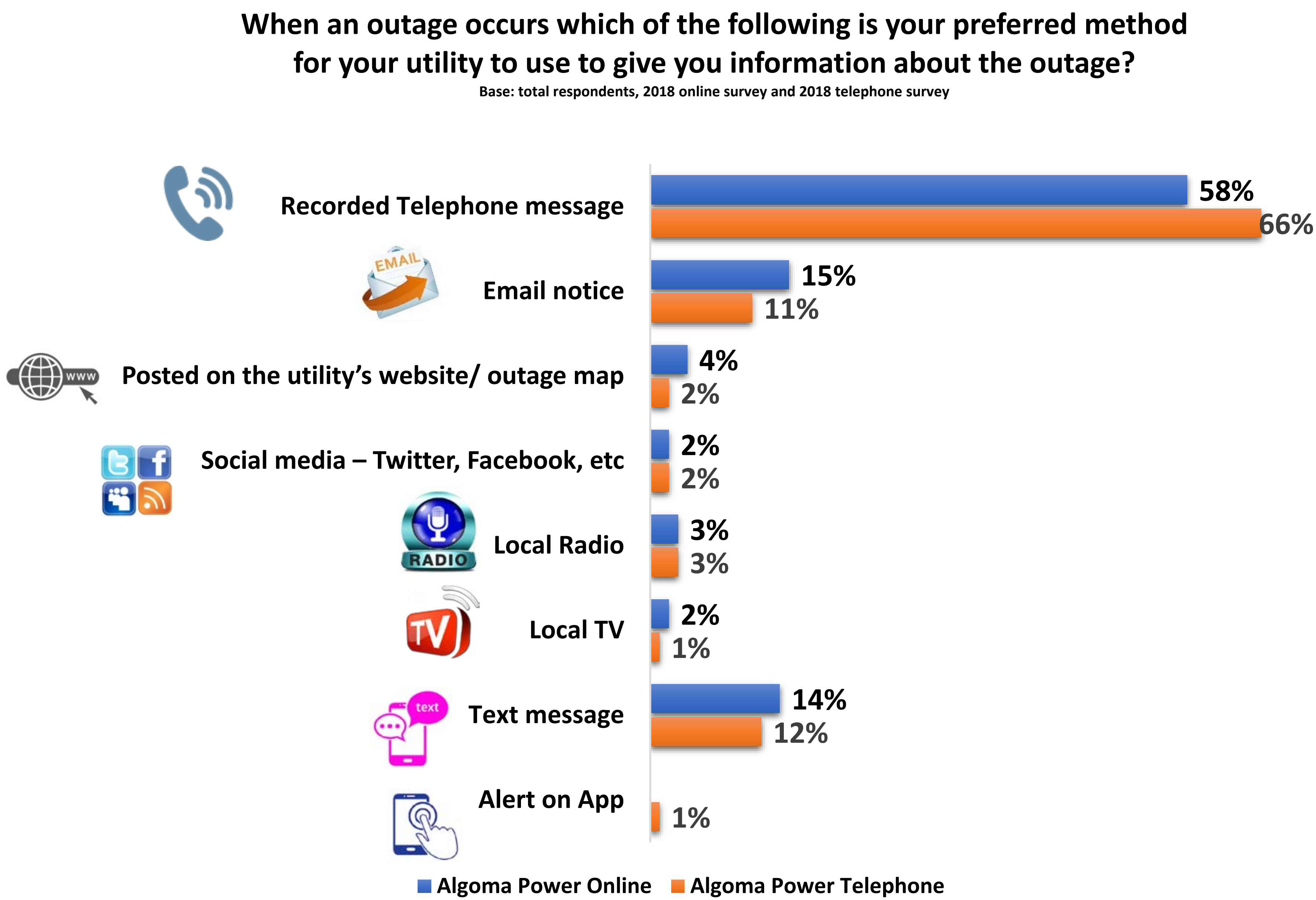
Online respondents claiming they experienced outages 4 hours or longer were asked about the impact of an outage when it is 4 hours or more. Respondents could pick multiple descriptors from a list; Algoma Power's respondents claimed the following:

- 81% "Inconvenient"
- 46% "Annoying"
- 42% "Stressful"
- 31% "Becomes a safety and security issue"
- 33% "Becomes a potential health issue"

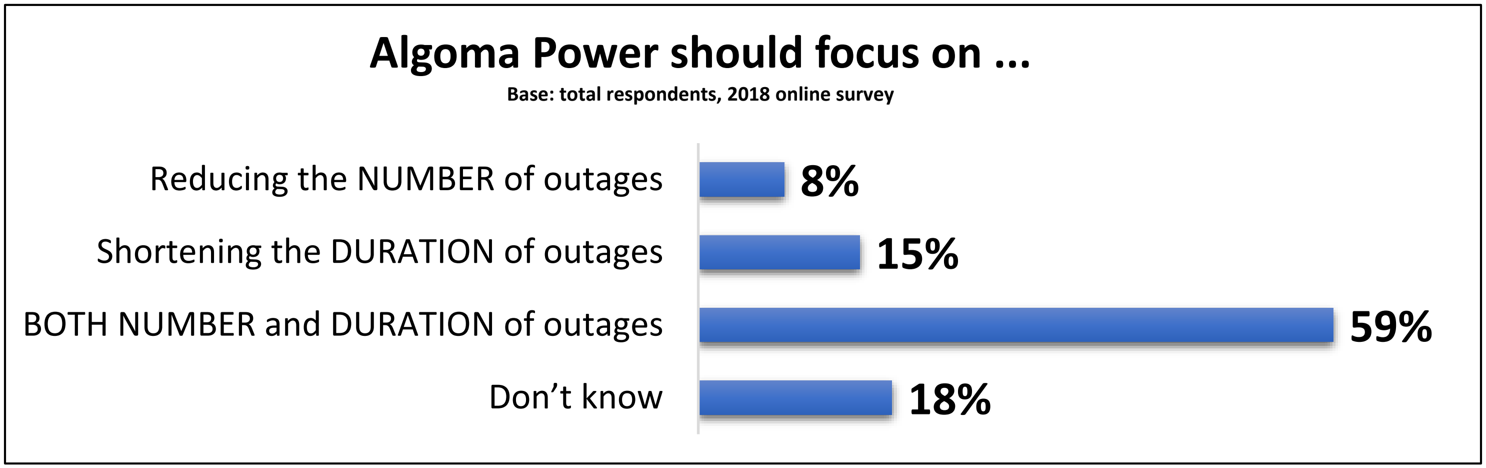
When an outage occurs which of the following is your preferred method for your utility to use to give you information about the outage?

	Algoma Power Online	Algoma Power Telephone	UtilityPULSE Database
Recorded Telephone message	58%	66%	33%
Email notice	15%	11%	21%
Posted on the utility's website/ outage map	4%	2%	4%
Social media – Twitter, Facebook, etc.	3%	2%	5%
Local Radio	2%	3%	5%
Local TV	0%	1%	3%
Text message	14%	12%	24%
Other	2%	0%	0%
Alert on App	--	1%	2%
Don't know	2%	2%	1%

Base: total respondents, 2018 online survey and 2018 telephone survey, UtilityPULSE database 5,812 LDC customers


When an outage occurs which of the following is your preferred method for your utility to use to give you information about the outage?
Base: total respondents, 2018 online survey and 2018 telephone survey
Recorded Telephone message
58%
66%
EMAIL
Email notice
15%
11%
www
Posted on the utility's website/ outage map
4%
2%
Social media – Twitter, Facebook, etc
2%
2%
RADIO
Local Radio
3%
3%
TV
Local TV
2%
1%
text
Text message
14%
12%
Alert on App
1%
Algoma Power Online
Algoma Power Telephone

In recent years, Algoma Power has had a renewed focus on improving reliability. Going forward, which of the following statements is closest to your viewpoint?



While 59% of respondents indicated when Algoma Power does tackle outage management the focus should be placed on both frequency and duration of outages, a subsequent question reveals 74% of respondents believe 'the standard of reliability is about right.'

Which of the following 3 statements is closest to your feelings about Algoma Power's standard of reliability?

Standard of Reliability

	Algoma Power Online
I believe the standard should improve, even if it does cost more money	6%
I believe the standard is about right	74%
I believe the standard can be lowered if it will save some money and not compromise safety	14%
Not sure	6%

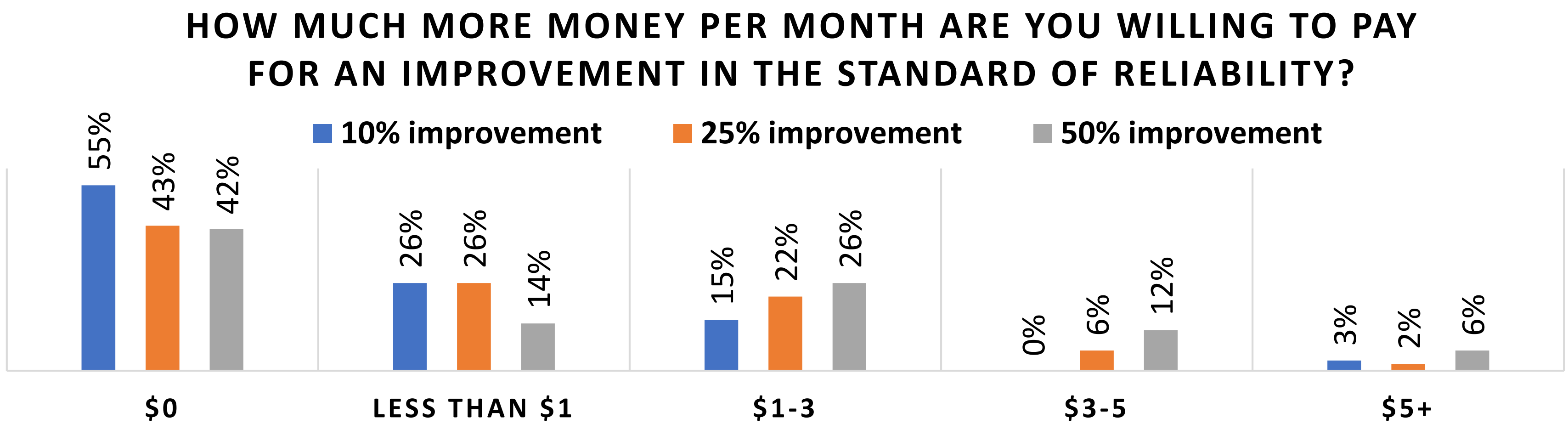
Base: total respondents, 2018 online survey

In both Chapter surveys #4 and #5, respondents were asked to what degree would they agree Algoma Power "has a standard of reliability delivering electricity that meets your expectations," 89% of Chapter survey #4 respondents and 96% of Chapter survey #5 respondents 'Agree Strongly or Somewhat' with the statement. In the Fall 2018 telephone survey 88% of respondents also 'Agree strongly or Somewhat.'

With such a high endorsement around Algoma Power's current standard of reliability, it is no wonder 40-50% of customer respondents are not willing to pay additional money for improving the standard. What the data does show is, willingness to pay more increases when improvement levels are demonstrably higher than the current standard.

Could you tell us how much more money per month you are willing to pay for an improvement in the standard of reliability?			
	10% improvement	**25% improvement**	**50% improvement**
$0	55%	43%	42%
Less than $1	26%	26%	14%
$1-3	15%	22%	26%
$3-5	0%	6%	12%
$5+	3%	2%	6%

Base: total respondents, 2018 online survey

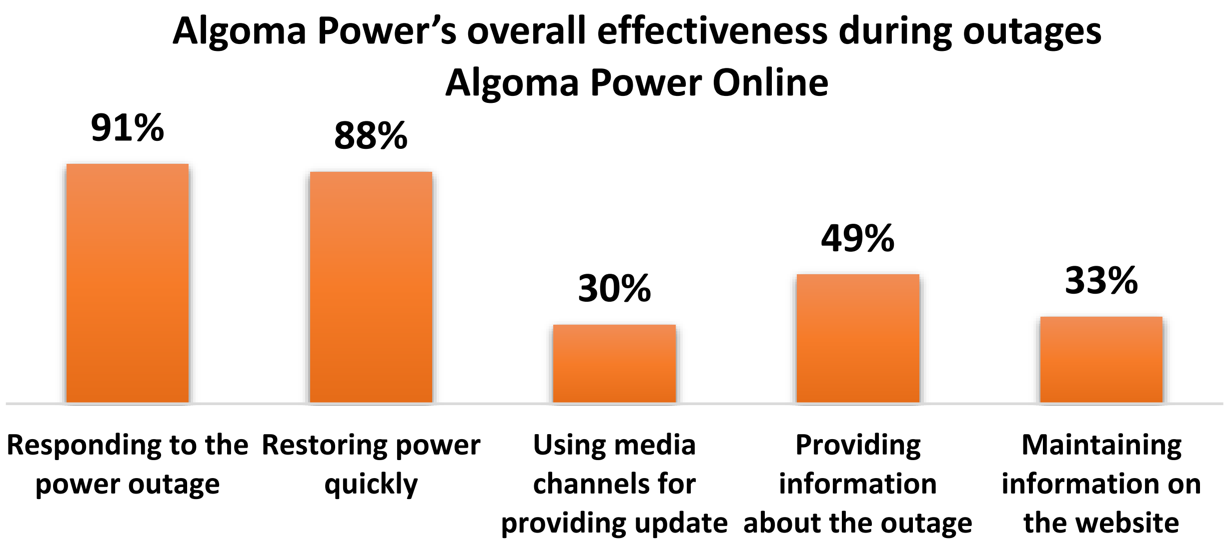


Algoma Power's overall effectiveness during outages	
Top 2 boxes "Very + Somewhat Effective'	**Algoma Power Online**
Responding to the power outage	91%
Restoring power quickly	88%
Using media channels for providing an update	30%
Providing information about the outage	49%
Maintaining information on the website	33%

Base: total respondents, 2018 online: Top 2 boxes "Very + Somewhat Effective'

Online customer respondents had very high "Don't know" responses for:

- 19% Using media channels
- 32% Maintaining information on the website



Base: total respondents, 2018 online: Top 2 boxes "Very + Somewhat Effective'

Chapter 5 "Help us prioritize capital investments in the electricity network"

Purpose of this Chapter:

1- To determine levels of support for various types of capital investments in the electricity network
2- To introduce to customer respondents the definitions of terms such as System Access, System Renewal, System Service and General Plant
3- To gather feedback as it relates to approaching the planning of capital investments
4- To gather feedback as it relates to approaching the planning of capital & operational expenses for facilities, tools & equipment
5- To provide another opportunity for customer respondents to provide ideas for keeping costs low, we call these items “Wisdom from Customers”

Topics:

- Consulting other electricity entities when planning capital expenses for the electricity network
- Meeting regulatory and legal requirements
- Replacing equipment
- Planning for the longer term
- Keeping facilities, tools, and equipment in good working order

Primary theme(s):

To what degree do you agree or disagree with the following attributes:					
Algoma Power	**Online 2018**	**Telephone 2018**	**Telephone 2017**	**Telephone 2016**	**Telephone 2015**
Algoma Power provides consistent, reliable electricity.	95%	89%	87%	85%	88%
Accurately bills its customers	94%	87%	86%	78%	86%
Has a standard of reliability delivering electricity that meets your expectations	96%	88%	88%	84%	84%
Quickly handles outages and restores power	93%	90%	85%	89%	88%
Is a trusted and trustworthy company	95%	84%	88%	81%	83%
Adapts well to changes in customer expectations	86%	77%	78%	70%	72%

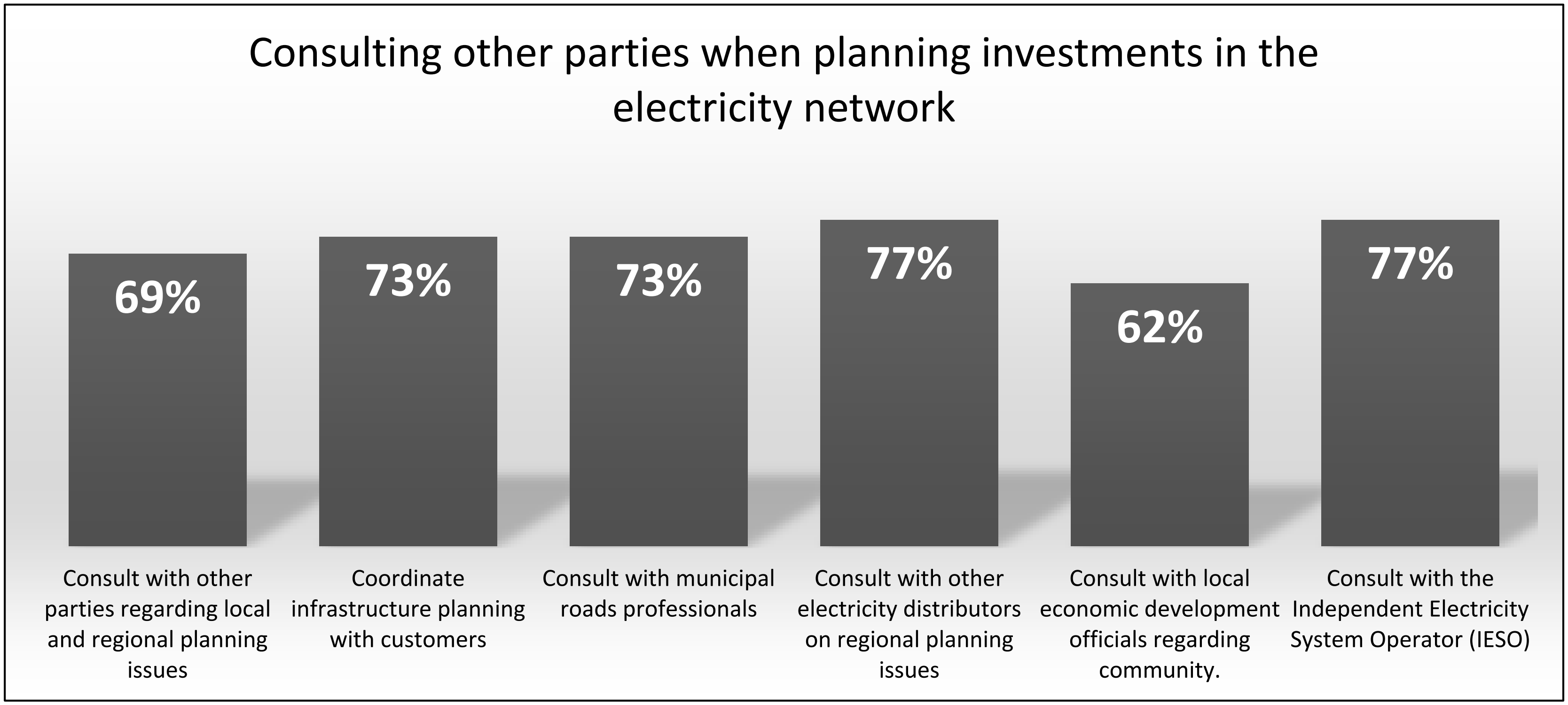
Base: total respondents with an opinion, 2018 online survey, and 2015-2018 telephone surveys

The findings above show Algoma Power survey respondents hold the company and its standards in high regard. Not perfect, and always room for improvement, we can say Algoma Power compares quite favourable with other Ontario LDCs. Also as the numbers above show, Algoma Power has quite a string of consistency. For readers of this report, 2016 and into the winter of 2017, was the time when Ontario LDC customers were "angry" about the costs of electricity. LDCs took some of the blame and as a result had lower scores.

Respondents were asked to comment on the importance of consulting other parties when planning investments in the electricity network. A majority of respondents believe in the importance of consulting other parties when planning investments.

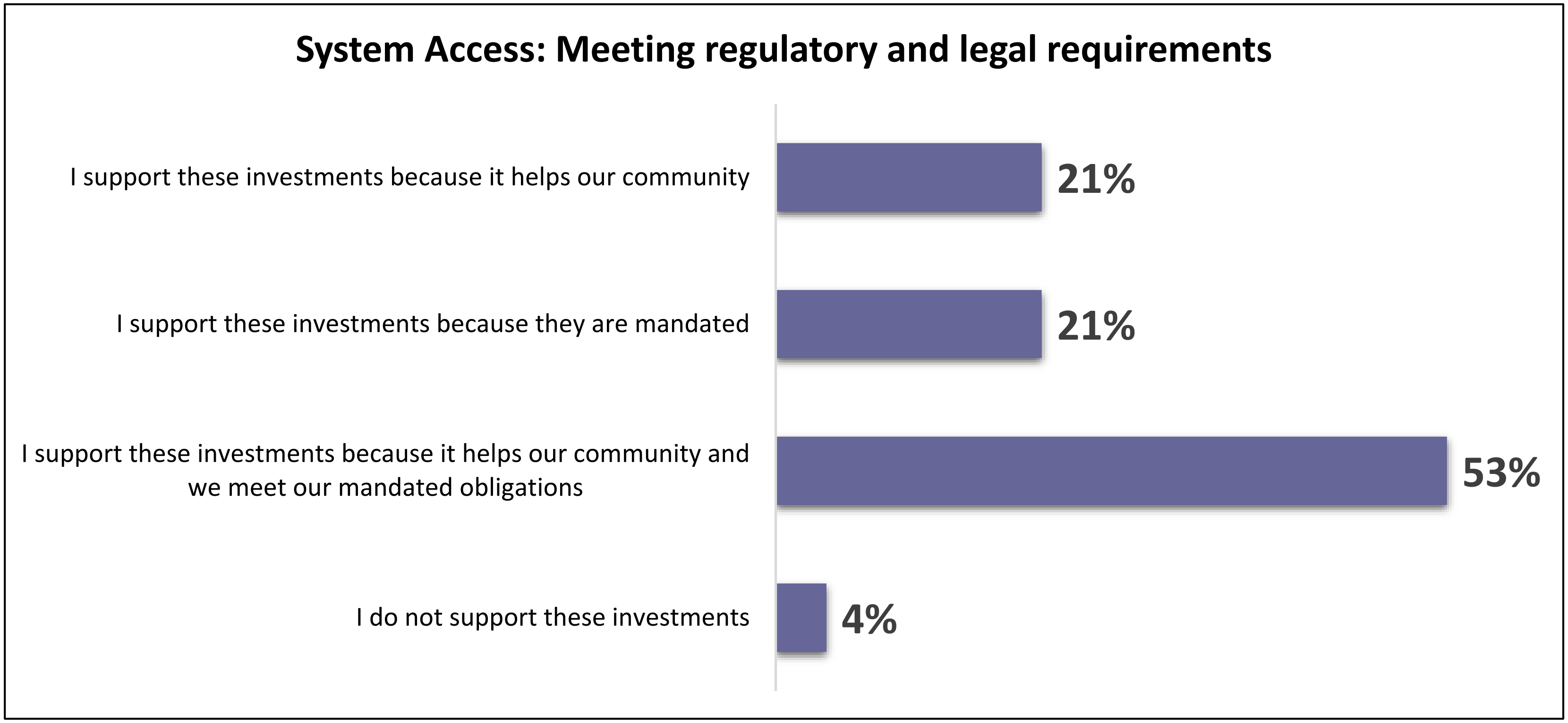
Consulting other parties when planning investments in the electricity network	
Top 2 boxes "Very + Somewhat Important'	**Algoma Power Online**
Consult with other parties regarding local and regional planning issues	69%
Coordinate infrastructure planning with customers	73%
Consult with municipal roads professionals	73%
Consult with other electricity distributors on regional planning issues	77%
Consult with local economic development officials regarding community economic outlook	62%
Consult with the Independent Electricity System Operator (IESO)	77%

Base: total respondents, 2018 online: Top 2 boxes "Very + Somewhat Important'



System access projects are mandated; Algoma Power must undertake these projects. The data shows, when “mandated” is coupled with a higher purpose, support for investment increases. The data also shows there are customer respondents who are not motivated to support these kinds of investments whether they are mandated or have a higher purpose.

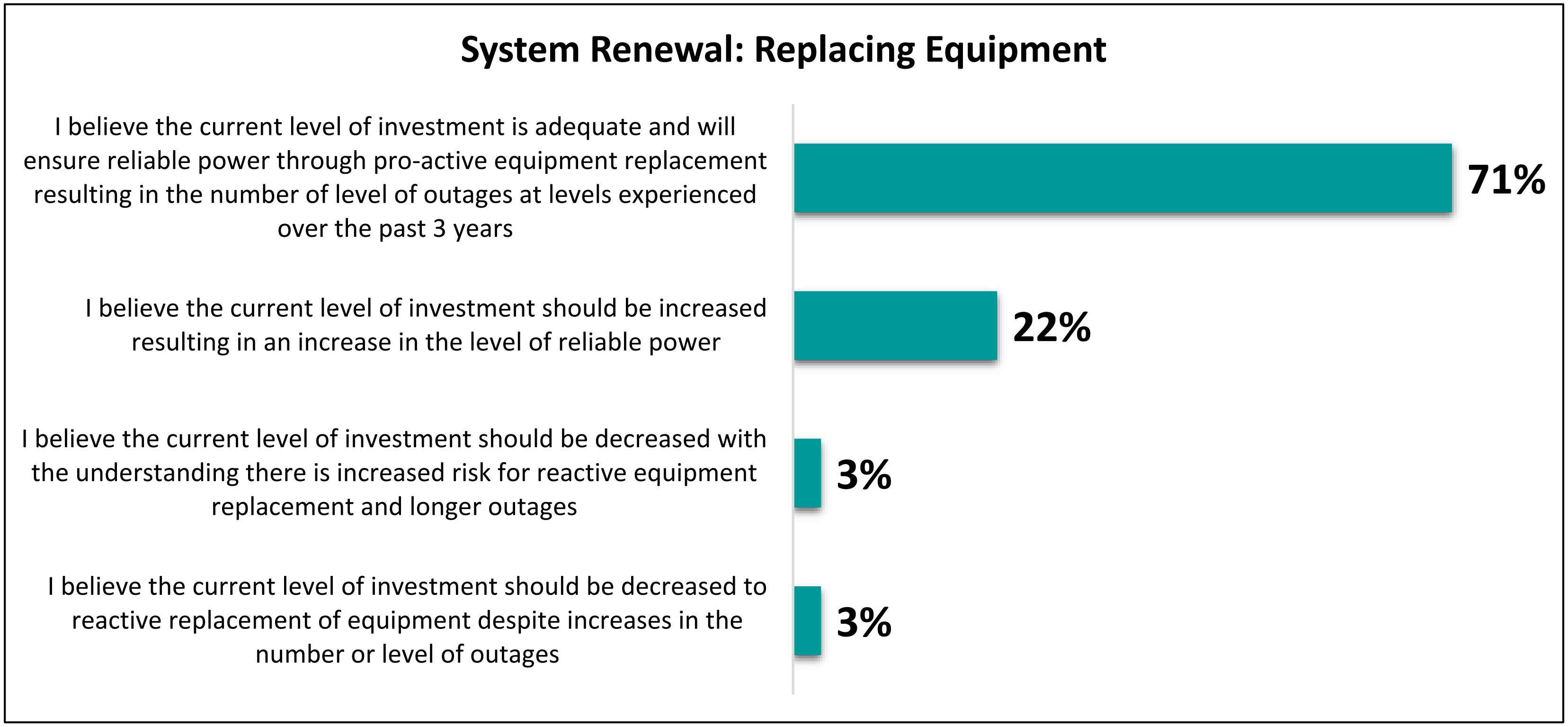
Could you tell us which of the following statements is closest to your viewpoint about System Access?



Base: total respondents, 2018 online survey

In Algoma Power's Fall 2018 telephone survey 87%, 86% of Chapter survey #3 online customer respondents, and 89% of 1,204 telephone interviews from the Fall 2018 UtilityPULSE database, indicated "Pro-actively maintaining and upgrading equipment" was a 'Very high or high priority.' These telephone findings coupled with online findings, shown below, tell us there is virtually no support for cutting back on system renewal investments.

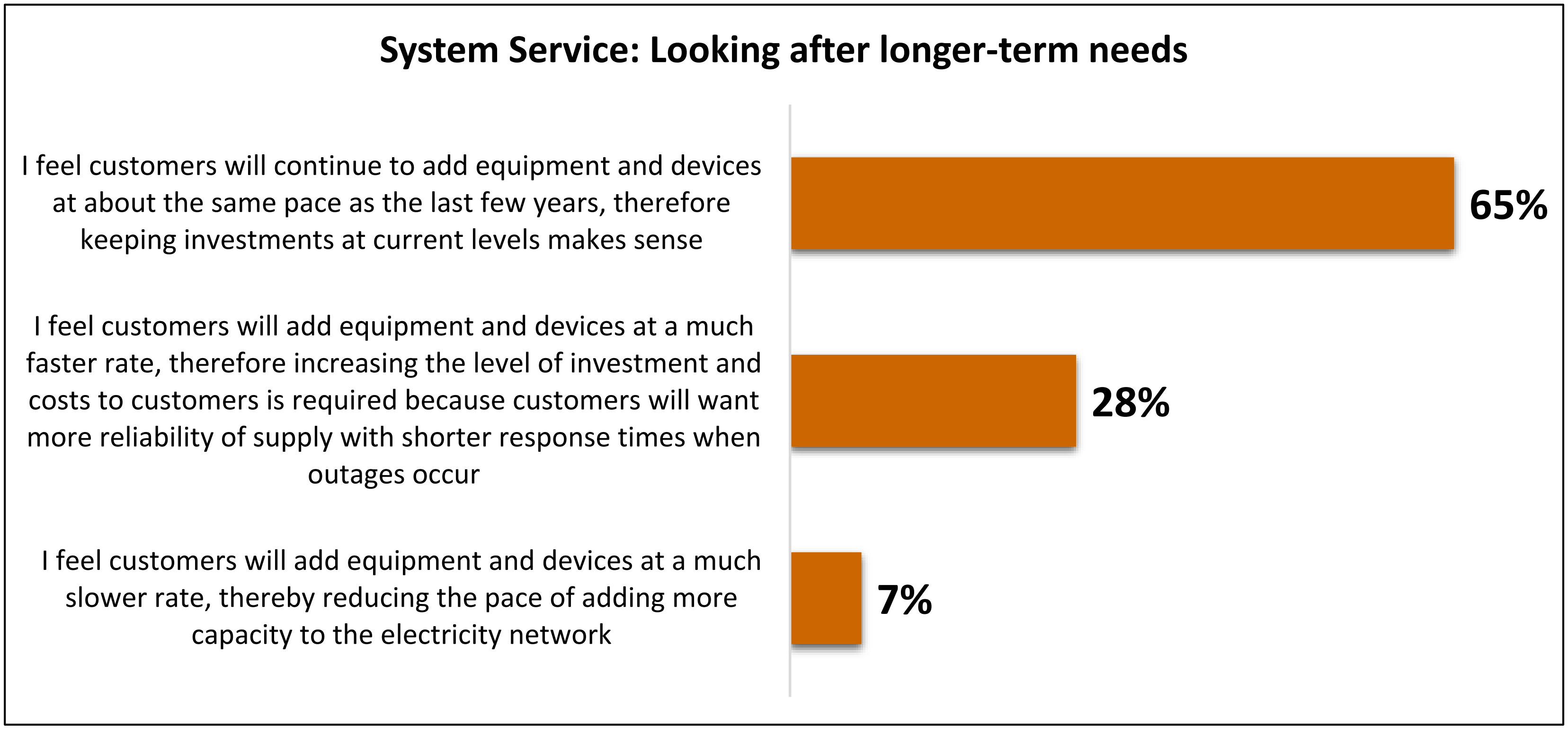
Which of the following statements is closest to your viewpoint about System Renewal Capital Investments?



Base: total respondents, 2018 online survey

Algoma Power customers are using more equipment and devices in their homes and businesses which are sensitive to power interruptions and power quality. System Service capital investments are about achieving performance objectives and meeting the future needs of all customers.

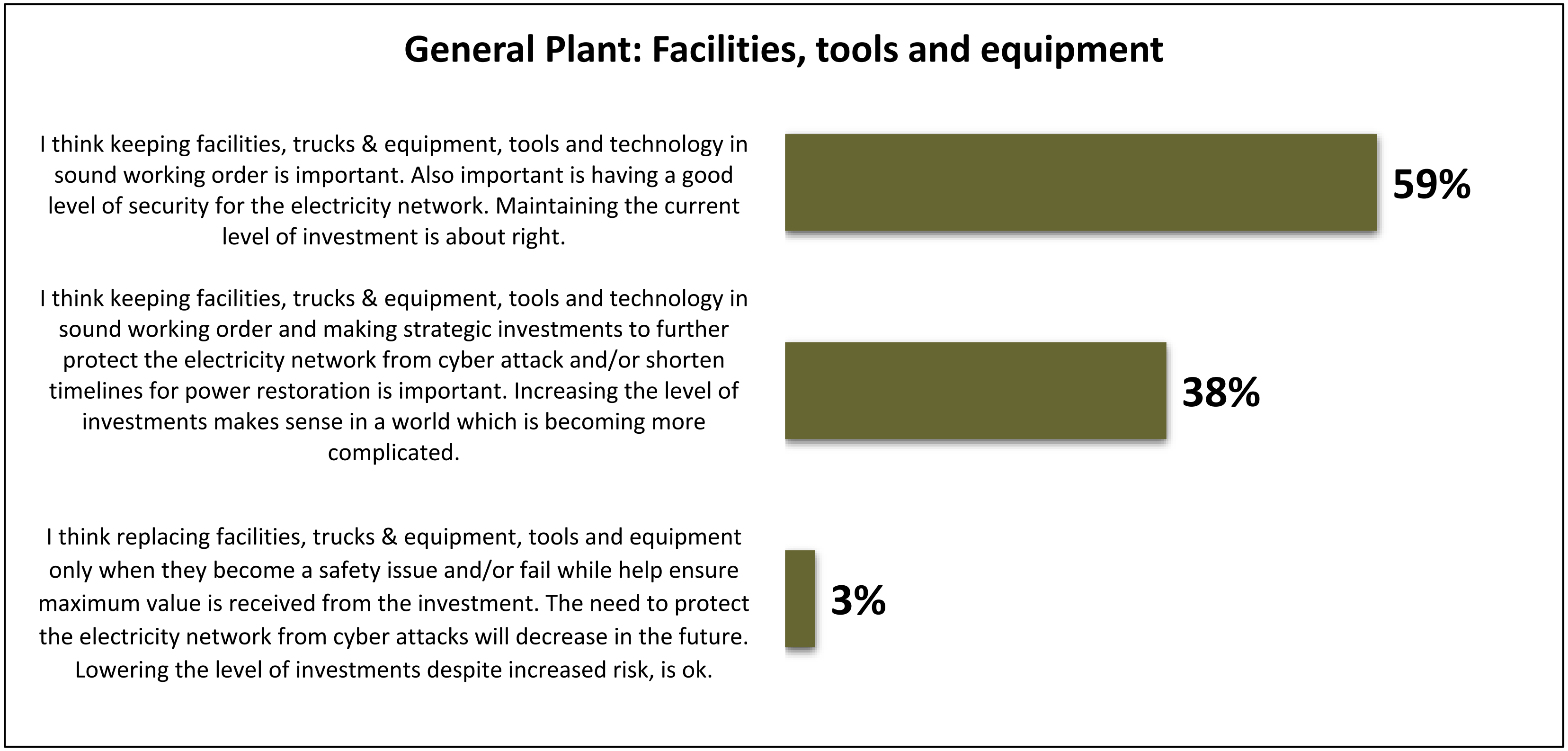
Which of the following statements is closest to describing your belief about the pace of adding equipment and devices which Algoma Power must keep in mind when developing the System Service budget and plan?



Base: total respondents, 2018 online survey

Having the right tools & equipment, efficient workplaces, good trucks, and other rolling equipment, computers and software help Algoma Power professionals support day to day business and operational needs. These items do wear-out or become out-dated. Also, modernizing security software to protect against cyber attacks and improving customer information systems is a high priority for Algoma Power and the industry.

Which of the following statements is closest to describing your level of support for the General Plant investment plan?



Base: total respondents, 2018 online survey

Chapter 6 "Gathering insights about customer care operations"

Purpose of this Chapter:

1- To gather feedback regarding customer respondent satisfaction levels with the amount of information available for various topics
2- To gain a better understanding of customer respondent willingness to pay more for various customer care operational improvements
3- To capture how important or unimportant various criteria should be considered when (potentially) addressing the need to make a long-term decision about Algoma Power's facilities
4- To provide another opportunity for customer respondents to provide ideas for keeping costs low, we call these items "Wisdom from Customers"

Topics:

- Communication
- Customer Care
- Facilities

Primary theme(s):

Insights. Findings. Feedback.

Utilities have an image even if they do not undertake any activities to try to build it. The brand of a company is its reputation. Just like a personal reputation, a brand reputation is formed based on the behaviours and actions of the company (or person), and how those behaviours and actions are perceived. Although reputation is an intangible concept, a strong corporate image makes it easier to capture the attention of more customers – more often. A company's image is both a simple and complex concept.

Algoma Power, along with all other Ontario LDCs, is known as an influential brand company because they affect the daily lives of people and businesses. The safe, reliable distribution of electricity to homes and businesses is a job which makes life better, more interesting and meaningful for consumers and customers. However, the company has to consistently demonstrate that it cares about its customers and it can be trusted.

The importance of an effective marketing communications plan cannot be overstated. The UtilityPULSE Fall 2018 database of 7,010 telephone interviews with customers shows customers who have a very low-affinity rate towards their LDC state they have almost 2X more outage problems than customers who have a high-affinity rate. Also, customers with a low-affinity rate are 8X more likely to say they have a billing problem vs. those who have a high-affinity rate.

In 2016 when Ontario LDC customers were “angry” about rates, affinity levels dropped and 25% of UtilityPULSE database respondents said they had a billing problem. In 2016, 10% of Secure respondents vs 56% of At Risk respondents said they had a billing issue. In 2018, when “anger” has been changed to “concern”, 9% total population, 2% Secure and 32% At Risk respondents indicated they had a billing problem. In 2016, call volumes, as they relate to bill issues, skyrocketed. A strong corporate image with high affinity levels with customers, has operational benefits.

To what degree do you agree or disagree with the following attributes:

Algoma Power	Online 2018	Telephone 2018	Telephone 2017	Telephone 2016	Telephone 2015
Is a trusted and trustworthy company	90%	84%	88%	81%	83%
Is a socially responsible company	86%	86%	87%	77%	83%
Is pro-active in communicating changes and issues which may affect customers	85%	83%	84%	78%	83%
Adapts well to changes in customer expectations	81%	77%	78%	70%	72%
Is a respected company in the community	86%	87%	83%	79%	83%

Base: total respondents with an opinion, 2018 online survey and 2015-2018 telephone surveys | Top 2 boxes “Strongly agree + somewhat agree’

Consumer Information and Communication

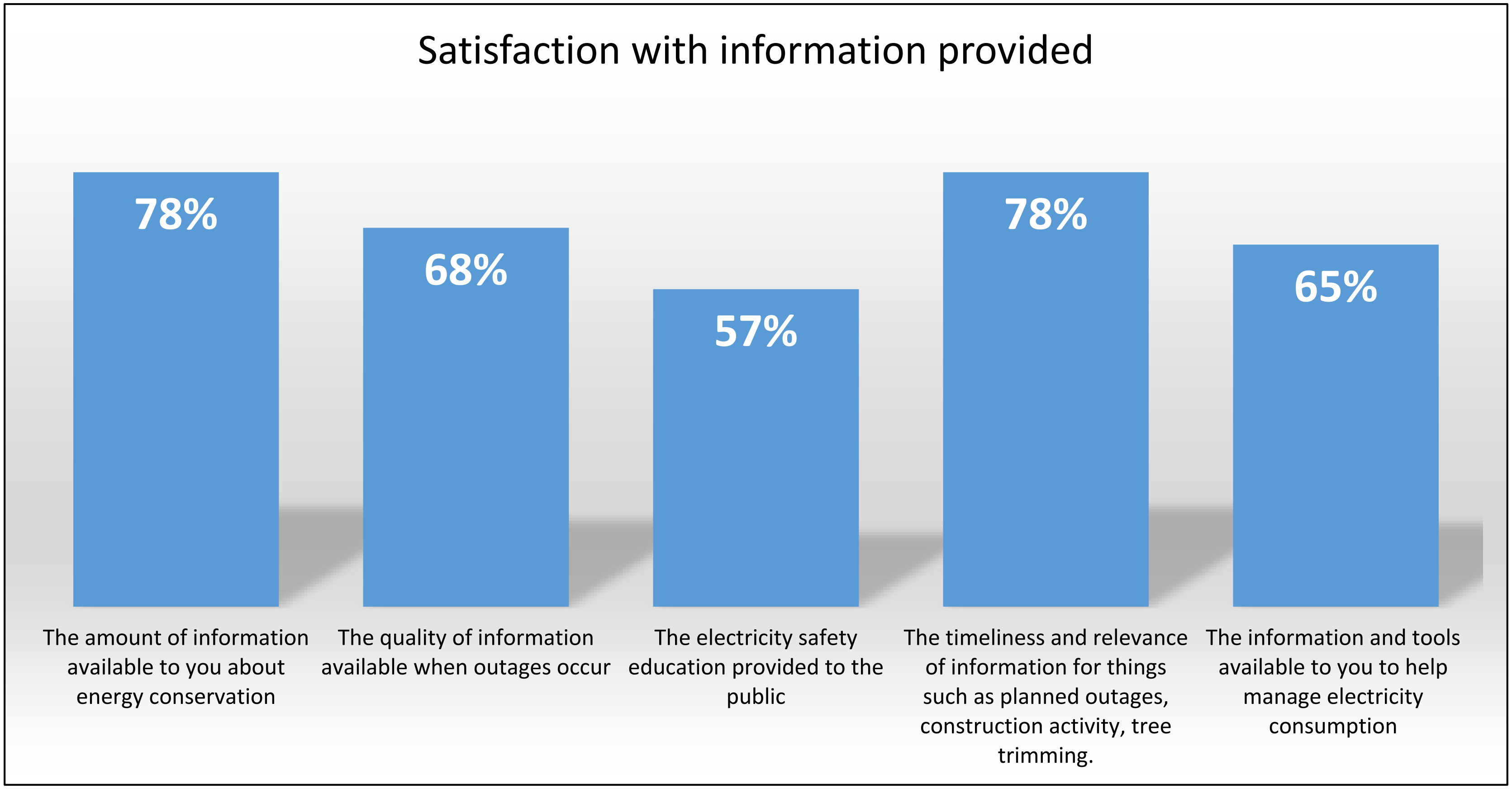
Electric utilities across Canada are increasingly seeing the need to invest in aging infrastructure, new technologies, regulatory requirements, and a skilled workforce. They are addressing these needs to uphold their public service duty, all the while keeping in mind the need to communicate with their customers. Part of communication is the requirement of providing information and/or education to customers (and in some case the public), to raise the level of understanding surrounding an issue or topic.

Consumer information is meant to attune consumers to certain problems [i.e., outage problems, etc.], create awareness and educate [i.e., electricity safety, etc.] or even guide (influence) their behaviour [i.e., energy conservation, etc.].

Customers, who are also consumers, have additional needs for information and education. Survey respondents were asked about their level of satisfaction with the information provided by Algoma Power on the following:

Satisfaction with information provided			
	Algoma Power Online	**Algoma Power Telephone**	**UtilityPULSE Database**
The amount of information available to you about energy conservation	78%	85%	82%
The quality of information available when outages occur	68%	78%	73%
The electricity safety education provided to the public	57%	79%	74%
The timeliness and relevance of information for things such as planned outages, construction activity, tree trimming.	78%	91%	78%
The information and tools available to you to help manage electricity consumption	65%	--	--

Base: total respondents, 2018 online survey and 2018 telephone survey, UtilityPULSE database 6,207 LDC customers | Top 2 boxes “Strongly satisfied + Somewhat satisfied’



Base: total respondents, 2018 online survey: Top 2 boxes “Strongly satisfied + Somewhat satisfied’

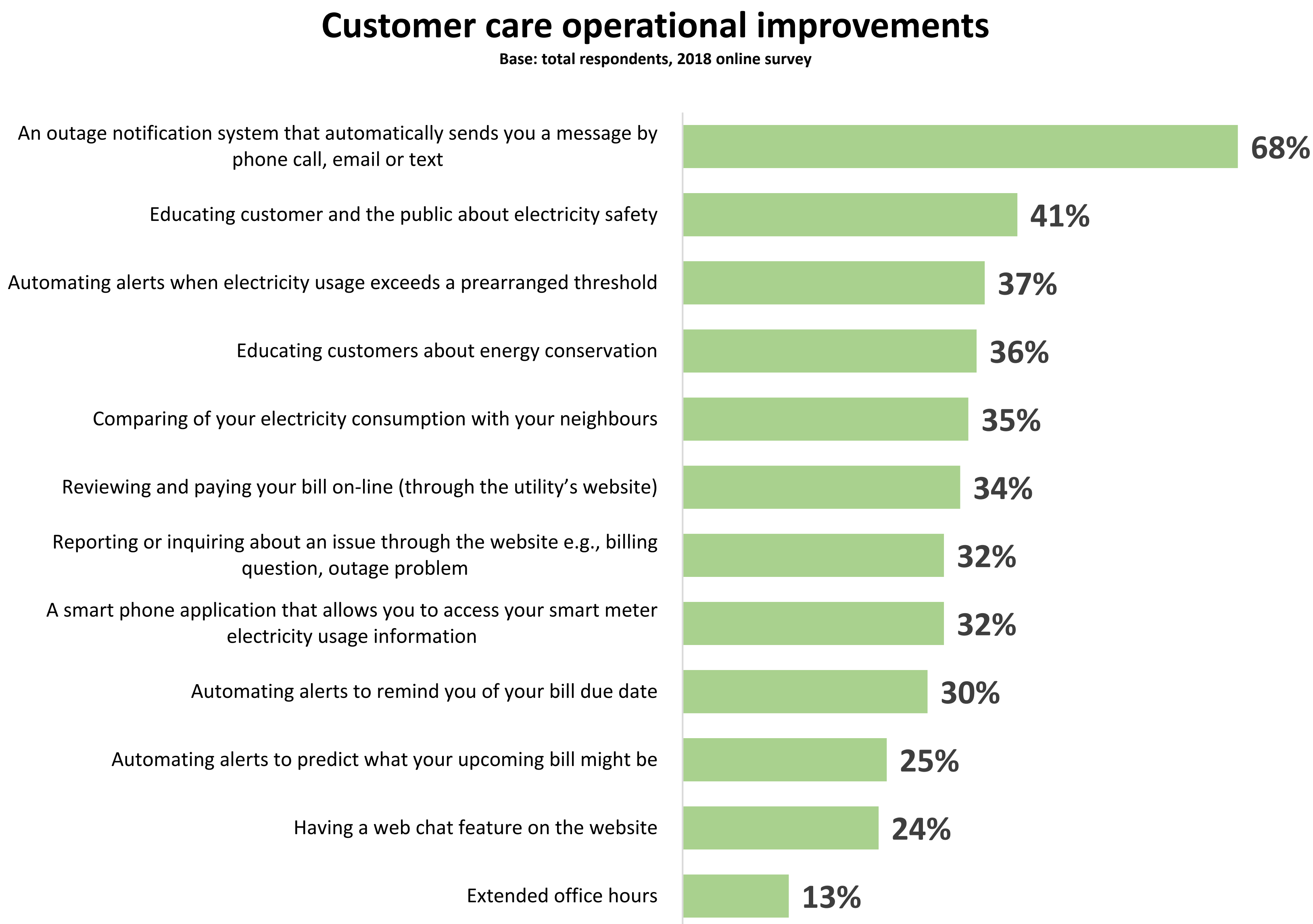
Customer Care

Customer expectations continue to rise, anticipating what those future expectations are, and when to implement them is a challenge.

As you think about the next 5 years, could you tell us to what degree you would be willing to pay more for each of the items?

Customer care operational improvements	
	Algoma Power Online
An outage notification system that automatically sends you a message by phone call, email or text	68%
Educating customer and the public about electricity safety	41%
Automating alerts when electricity usage exceeds a prearranged threshold	37%
Educating customers about energy conservation	36%
Comparing your electricity consumption with your neighbours	35%
Reviewing and paying your bill online (through the utility's website)	34%
Reporting or inquiring about an issue through the website, e.g., billing question, outage problem	32%
A smartphone application that allows you to access your smart meter electricity usage information	32%
Automating alerts to remind you of your bill due date	30%
Automating alerts to predict what your upcoming bill might be	25%
Having a web chat feature on the website	24%
Extended office hours	13%

Base: total respondents, 2018 online survey: Top 2 boxes "Strongly agree + Somewhat agree'


Customer care operational improvements
Base: total respondents, 2018 online survey
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Comparing of your electricity consumption with your neighbours
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A smart phone application that allows you to access your smart meter electricity usage information
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Automating alerts to remind you of your bill due date
30%
Automating alerts to predict what your upcoming bill might be
25%
Having a web chat feature on the website
24%
Extended office hours
13%

Facilities

Determining whether Algoma Power should retro-fit or renovate facilities or build new is a difficult decision with complex answers. Also, customers have a wide range of views regarding retro-fitting or replacing facilities. A decision about facilities is a long-term decision and can involve a tremendous amount of investment. The reality is, facilities do need to be updated.

The data shows customer respondents take a pragmatic view towards retro-fitting or replacing.

Could you tell us how important each of the following items are in helping to make a long-term decision about Algoma Power's facilities?

Facilities	
	Algoma Power Online
Facilities are safe and secure places to work	94%
Valuable inventory, parts, and equipment are protected	92%
Design of facilities encourages labour efficiency	88%
Facilities meet the needs of customers	88%
The decision to renovate or build new should be based on which option represents the best balance between keeping costs low, being efficient, and meeting customer longer term energy needs	88%
Are functional places to work, i.e., good ergonomics, lighting, temperature, encourages communication, etc.	86%
Facilities look to be in good repair and up-to-date	82%
Facilities suitability reflect the important nature of your electric utility in the community	60%
Esthetically fits in nicely with the community	55%

Base: total respondents, 2018 online survey: Top 2 boxes "Very important + Somewhat important'

Facilities

Base: total respondents, 2018 online survey

Chapter 7 "Help us determine which capital investments and operational changes you can support"

Purpose of this Chapter:

1- To gather insight into customer respondent preferences for proposed capital investments
2- To gauge customer respondent preferences when addressing the topic of facilities
3- To gather feedback regarding the level of support for various Customer Care changes, enhancements or additions
4- To provide another opportunity for customer respondents to provide ideas and insights into how the LDC could save money
5- To provide customer respondents with a mechanism to provide additional comments and be informed about any future public meetings regarding the COS application
6- To provide customer respondents with feedback regarding their support for Algoma Power's recommended choice. For example, respondents could receive a calculated web-page which would show how many of the API recommendations they had supported
7- To provide customer respondents with a summary of the Customer Care Operational changes, enhancements or additions they had supported
8- To offer customer respondents with a mechanism to have an Algoma Power professional contact them, we call these "Hot Alerts"
9- To provide customer respondents with an opportunity to complete chapter surveys 1 through 6.

Topics:

- Specific DSP topics
- Capital and other investments for Operations
- Customer care operational changes/enhancements

Primary theme(s):

Insights. Findings. Feedback.

Customer respondents were asked how satisfied they were with Algoma Power's services.

Satisfaction with Algoma Power's Services			
	Algoma Power Online	**Algoma Power Telephone**	**Ontario Benchmark**
2018	87%	93%	91%
2017	--	88%	85%
2016	--	79%	81%
2015	--	92%	86%

Base: total respondents: Top 2 Boxes: 'Very Satisfied + Somewhat Satisfied'

Algoma Power has a rural distribution system which is reflective in the delivery rates for our customers. Delivery rates are impacted by customer density, the location of customers relative to each other, terrain, and the size of the service territory. For the average customer who uses about 750 kWh per month of electricity their total bill is about $123 per month. Algoma Power is responsible for delivering electricity reliably and safely to its 11,700 customers. Algoma Power receives approximately 30% or $37 of the total amount to maintain the electricity network, build capacity to support economic growth, protect the network from cyber attack, and so much more. Algoma Power receives further funding to maintain and invest in its distribution system through subsidies related to rate protection for rural and remote customers.

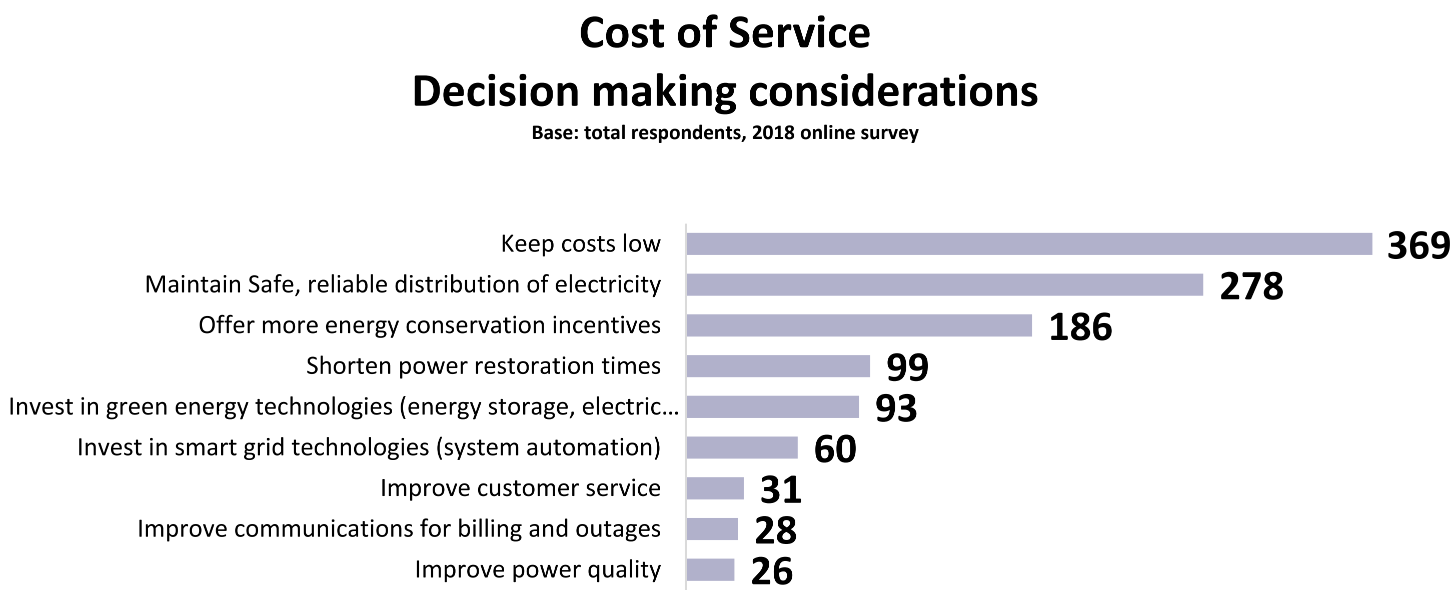
60% of Customer respondents said the amount was very or somewhat reasonable.

An important aspect of ensuring customer needs are being met is to solicit information about how decisions, which affect costs to customers, should be made. Customer respondents were asked to rank the following decision criteria. It is not surprising, keeping costs low and maintaining the safe, reliable distribution of electricity were the top two ranked items.

Could you prioritize the top 3 items we need to consider as we complete our Cost of Service (COS) application?

COS Decision-making considerations	
	Algoma Power Point Rankings
Keep costs low	369
Maintain safe, reliable distribution of electricity	278
Offer more energy conservation incentives	186
Shorten power restoration times	99
Invest in green energy technologies (energy storage, electric vehicles...)	93
Invest in smart grid technologies (system automation)	60
Improve customer service	31
Improve communications for billing and outages	28
Improve power quality	26

Base: total respondents, 2018 online survey

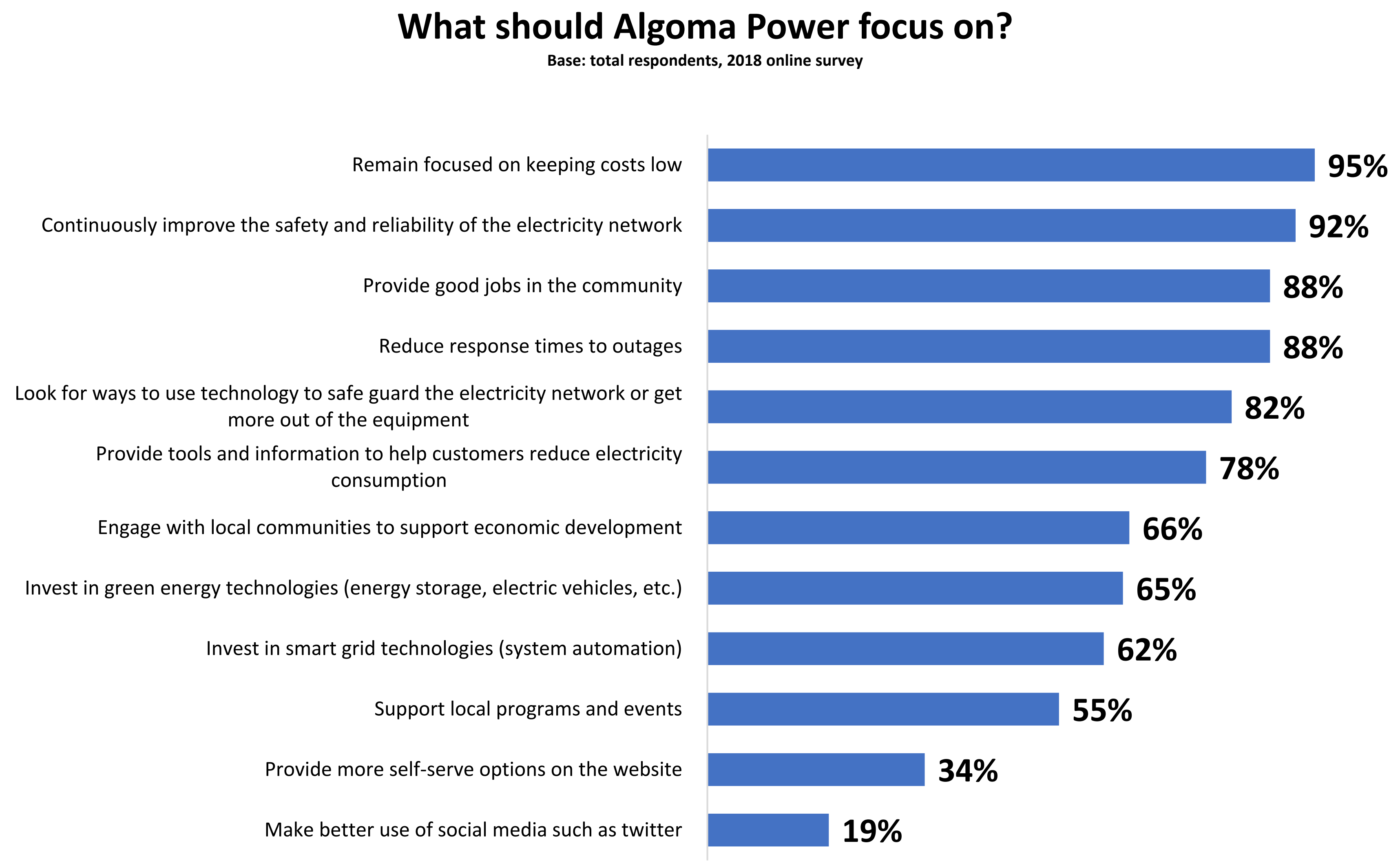


Customer respondents were asked:

Could you tell us how important each of the following items is to you?

What should Algoma Power focus on?	
	Algoma Power Online
Remain focused on keeping costs low	95%
Continuously improve the safety and reliability of the electricity network	92%
Reduce response times to outages	88%
Provide good jobs in the community	88%
Look for ways to use technology to safeguard the electricity network or get more out of the equipment	82%
Provide tools and information to help customers reduce electricity consumption	78%
Engage with local communities to support economic development	66%
Invest in green energy technologies (energy storage, electric vehicles, etc.)	65%
Invest in smart grid technologies (system automation)	62%
Support local programs and events	55%
Provide more self-serve options on the website	34%
Make better use of social media such as twitter	19%

Base: total respondents, 2018 online survey: Top 2 Boxes: 'Very important + Somewhat important'


What should Algoma Power focus on?
Base: total respondents, 2018 online survey
Remain focused on keeping costs low
95%
Continuously improve the safety and reliability of the electricity network
92%
Provide good jobs in the community
88%
Reduce response times to outages
88%
Look for ways to use technology to safe guard the electricity network or get more out of the equipment
82%
Provide tools and information to help customers reduce electricity consumption
78%
Engage with local communities to support economic development
66%
Invest in green energy technologies (energy storage, electric vehicles, etc.)
65%
Invest in smart grid technologies (system automation)
62%
Support local programs and events
55%
Provide more self-serve options on the website
34%
Make better use of social media such as twitter
19%

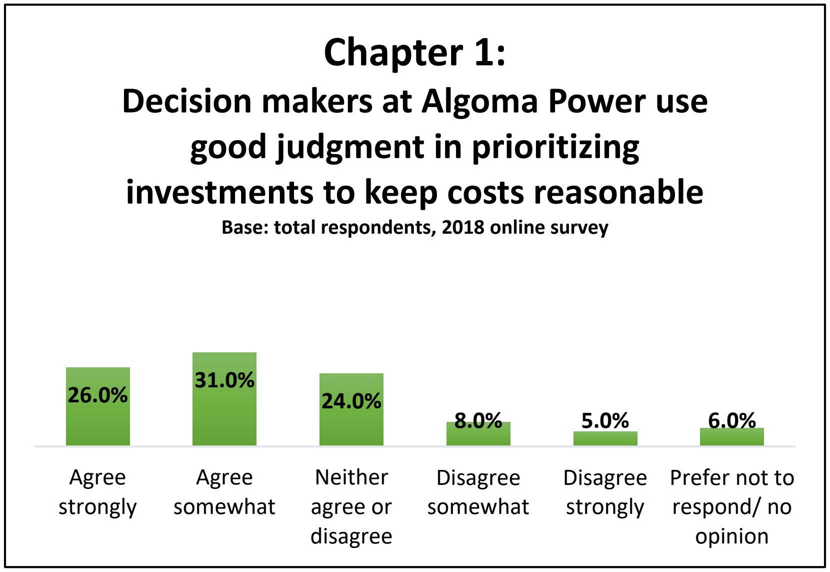
Ensuring Algoma Power has its customers' support to pursue project investments is very important. In Chapter 1, customer respondents were asked if they agreed Algoma Power uses good judgment in prioritizing investments to keep costs reasonable.

Here in Chapter 7, the topic of using good judgment for prioritizing capital investment projects is revisited by asking respondents about their level of confidence in Algoma Power's ability to do the aforementioned. The data is clear, the majority of customer respondents indicate they have confidence in Algoma Power to use good judgment when prioritizing and making capital investments

Chapter 7: Could you tell us the level of confidence you have in the people at Algoma Power to use good judgment for prioritizing capital investment projects?

Confidence in Decision Makers – Chapter 7	Algoma Power Online
Very confident	31%
Somewhat confident	43%
Neither confident or unconfident	13%
Somewhat unconfident	5%
Very unconfident	1%
Don't know	9%

Base: total respondents, 2018 online survey: Top 2 Boxes: 'Very confident + Somewhat confident'



Though these questions are "different", they do demonstrate that the majority of survey respondents recognize the professional abilities of Algoma Power decision-makers.

Rate Setting

Algoma Power has a rural distribution system which is reflective in the delivery rates to its customers. Delivery rates are impacted by customer density, the location of customers relative to each other, terrain, and the size of the service territory.

The Ontario Government and the Ontario Energy Board have established a formula for Algoma Power's customers which limit any increases in the distribution rates Algoma Power charges to residential, commercial and industrial customers. The increase to Algoma Power's distribution rates for these customer classes can be no higher than the average cost increase experienced by customers of other licensed electricity distributors in Ontario.

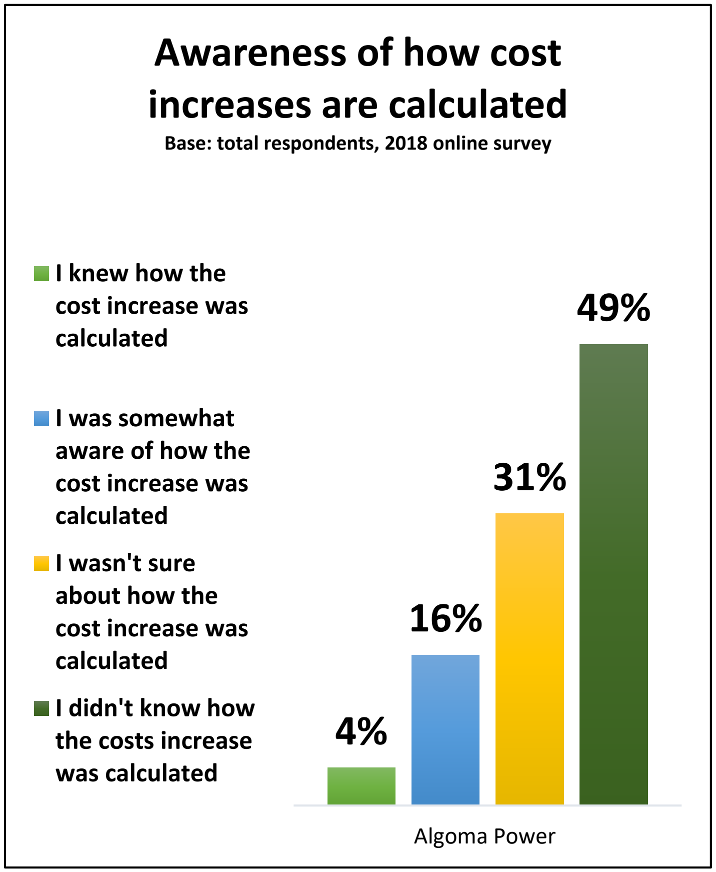
Prior to reading the above, what was your level of knowledge about how the annual cost increase is calculated for Algoma Power customers?

It is clear customer respondents do not know much about the system which is used to calculate annual cost increases.

Awareness of how cost increases are calculated

	Algoma Power Online
I knew how the cost increase was calculated	4%
I was somewhat aware of how the cost increase was calculated	16%
I wasn't sure about how the cost increase was calculated	31%
I didn't know how the costs increase was calculated	49%

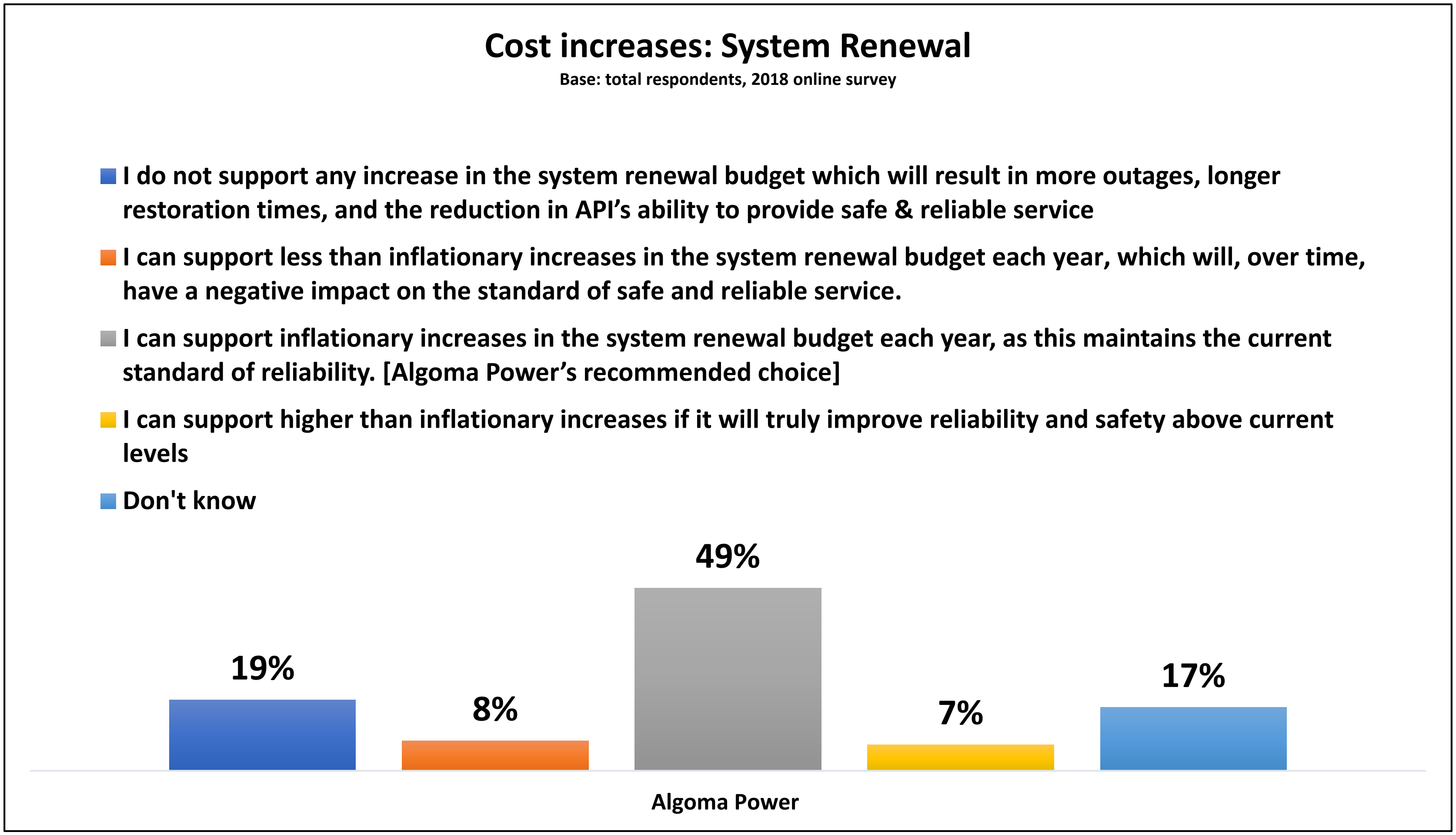
Base: total respondents, 2018 online survey



System Renewal

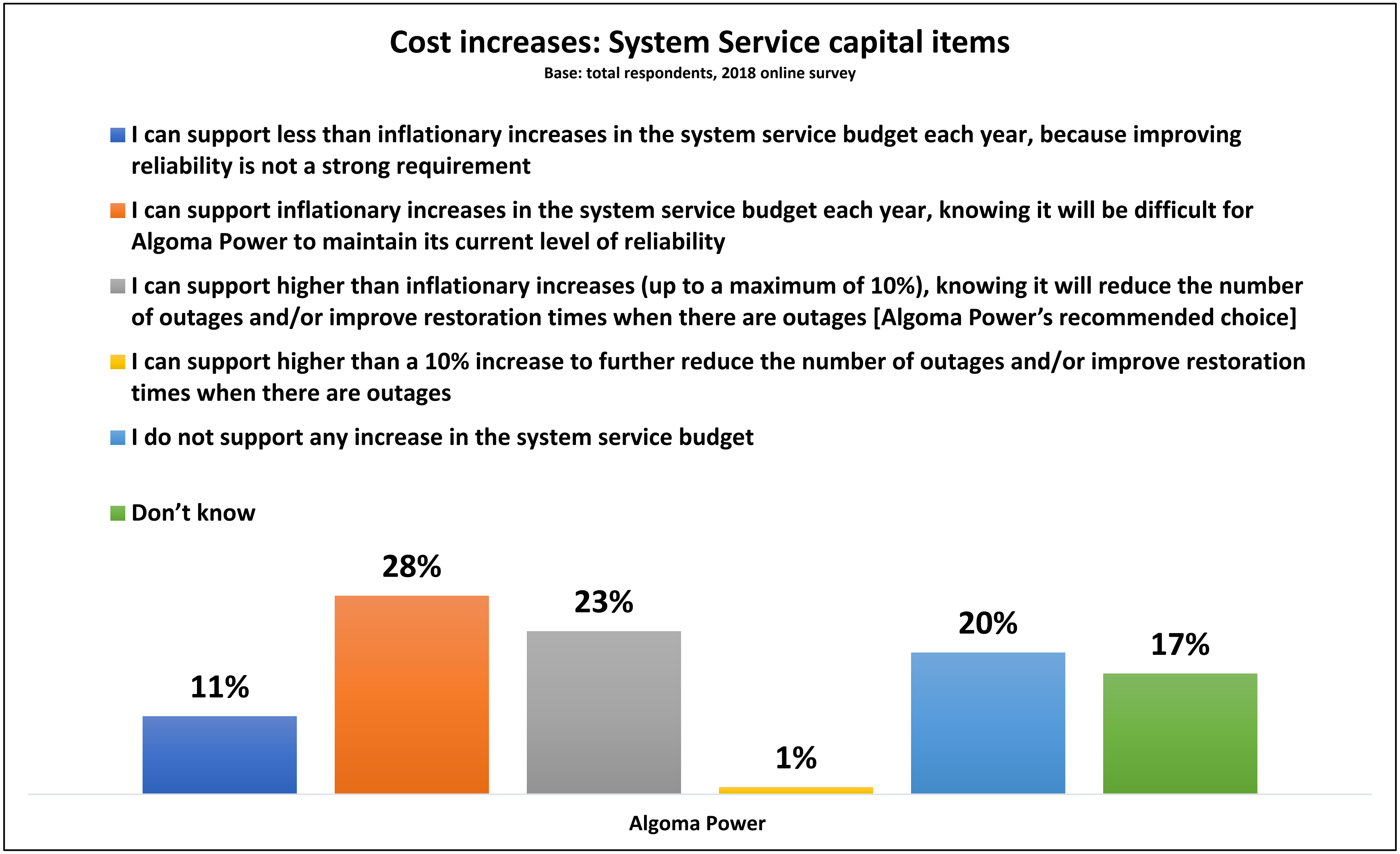
The unique nature of how Algoma Power cost increases limits are set allowed us to use descriptive statements of potential guiding principles for capital investments in System Renewal, System Service, General Plant and, Vegetation Management. It is important to note, Algoma Power's recommended approach was clearly identified in each question.

Algoma Power invests about $2,300,000 per year on System Renewal projects.
What level of monthly increase for the average customer could you support?



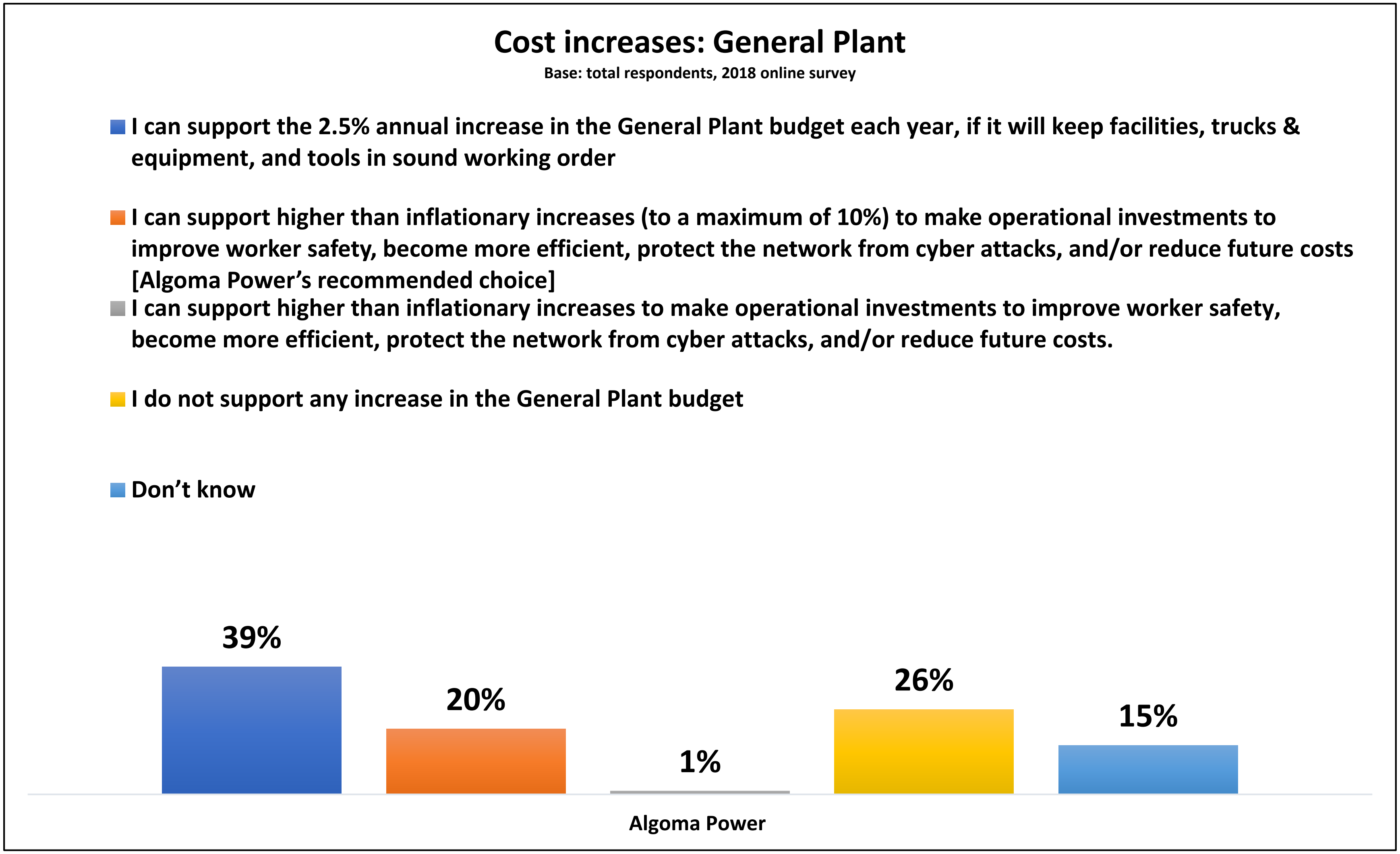
System Service

Algoma Power invests about $780,000 per year on System Service capital items. What level of monthly increase for the average customer could you support?



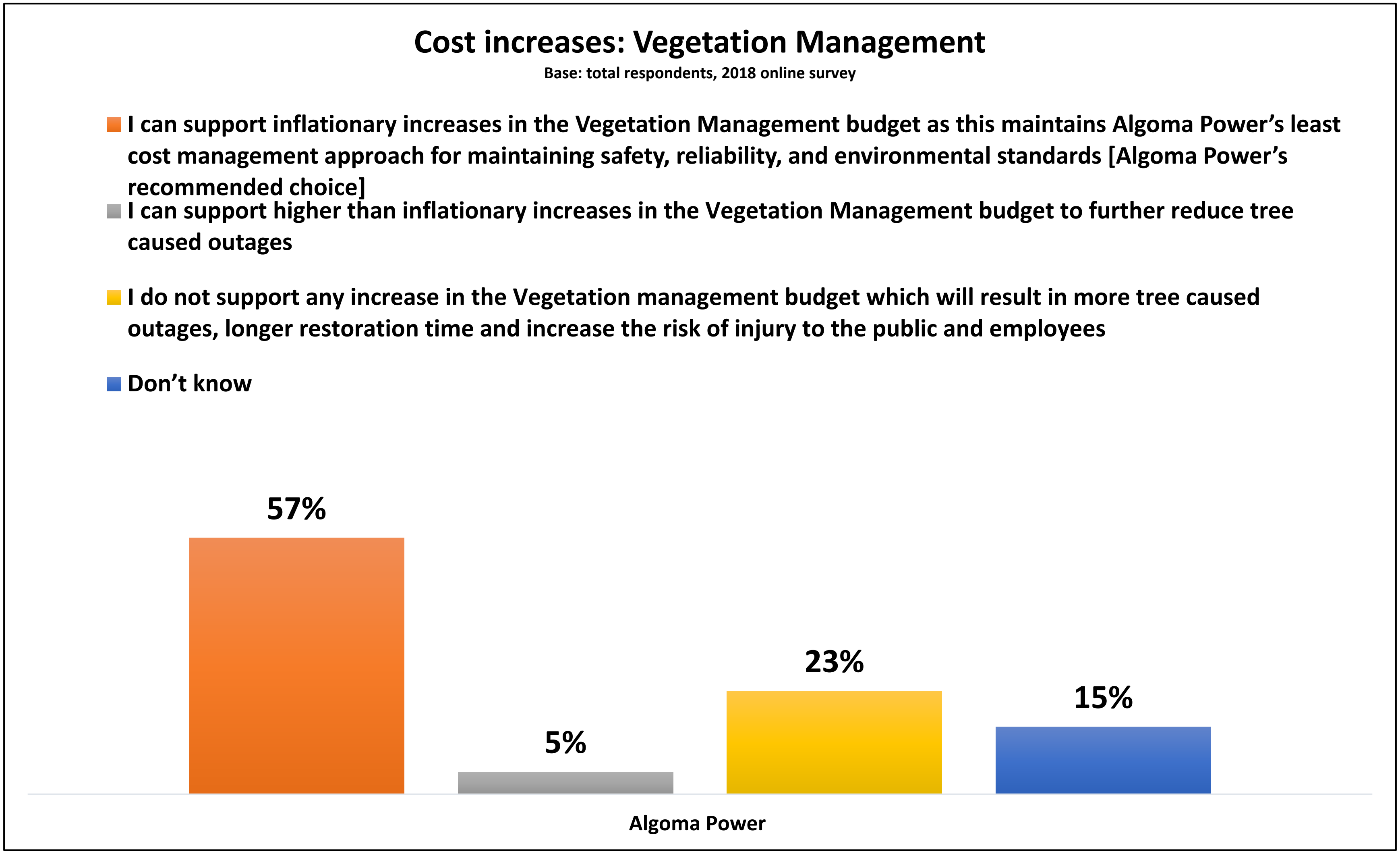
General Plant

Algoma Power invests about $925,000 per year on General Plant items.
What level of monthly increase for the average customer could you support?



Vegetation Management

Algoma Power invests about $3.4 million per year on Vegetation Management.
What level of monthly increase for the average customer could you support?



Algoma Power online survey findings show, 8% of customer respondents do not support any increase for any of the four items (system renewal, system service capital items, general plant, and vegetation management). Recognizing that costs do rise every year, customer respondents who chose not to support any increases are demonstrating, despite negative consequences, their deep concern about costs. We have heard the argument if respondents were more knowledgeable, they would support a rational decision. Unfortunately, decisions are rarely rational; they are emotional.

The reality is, customer respondents are being asked difficult questions, all of which have complicated answers. It isn't surprising there were, on average, 16% of customer respondents who selected "Don't know" as their answer.

What is important, despite the numbers of respondents who do not support any increase for any item, a majority of customer respondents supported inflationary level increases. And, there were 20%+ respondents supporting higher than inflationary increases for System Service and General Plant investments.

Customer Care Operational Improvements

Which of the following improvements would you like us to make?

Customer Care Operational improvements	
	Algoma Power Online
An outage notification system that automatically sends you a message by phone call, email or text	83%
Educating customers about energy conservation	53%
Reporting or inquiring about an issue through the website, e.g., billing question, outage problem	50%
Educating customer and the public about electricity safety	47%
Reviewing and paying your bill online (through the utility's website)	45%
Automating alerts when electricity usage exceeds a prearranged threshold	35%
Access online account info for updates, move-outs, and move-ins.	32%
Comparing your electricity consumption with others in API's service territory	30%
A smartphone application that allows you to access your smart meter electricity usage information	27%
Automating alerts to remind you of your bill due date	24%
Automating alerts to predict what your upcoming bill might be	21%
Having a web chat feature on the website	18%
Extended office hours	7%

Base: total respondents, 2018 online survey


Customer care operational improvements
Base: total respondents, 2018 online survey
An outage notification system that automatically sends you a message by phone call, email or text
83%
Educating customers about energy conservation
53%
Reporting or inquiring about an issue through the website e.g., billing question, outage problem
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Educating customer and the public about electricity safety
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Reviewing and paying your bill on-line (through the utility's website)
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Automating alerts when electricity usage exceeds a prearranged threshold
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Access on-line account info for updates, move-outs and move-ins.
32%
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30%
A smart phone application that allows you to access your smart meter electricity usage information
27%
Automating alerts to remind you of your bill due date
24%
Automating alerts to predict what your upcoming bill might be
21%
Having a web chat feature on the website
18%
Extended office hours
7%

Ensuring Algoma Power has its customers' support to pursue customer care operational improvements is essential. In Chapter survey #6, customer respondents were asked about their willingness to pay for customer care operational improvements.

Here in Chapter 7, this topic is revisited by asking respondents which improvements they would like Algoma Power to undertake. The congruency in the responses rendered in Chapter 6 and Chapter 7 emphasizes the support of the customer base in Algoma Power's to undertake the various customer care operational improvements.

Customer Care Operational improvements		
	Chapter 7: Improvements to undertake	**Chapter 6: Willingness to pay for improvements**
An outage notification system that automatically sends you a message by phone call, email or text	83%	68%
Educating customers about energy conservation	53%	36%
Reporting or inquiring about an issue through the website, e.g., billing question, outage problem	50%	32%
Educating customer and the public about electricity safety	47%	41%
Reviewing and paying your bill online (through the utility's website)	45%	34%
Automating alerts when electricity usage exceeds a prearranged threshold	35%	37%
Access online account info for updates, move-outs, and move-ins	32%	--
Comparing your electricity consumption with others in API's service territory	30%	35%
A smartphone application that allows you to access your smart meter electricity usage information	27%	32%
Automating alerts to predict what your upcoming bill might be	21%	25%
Automating alerts to remind you of your bill due date	24%	30%
Having a web chat feature on the website	18%	24%
Extended office hours	7%	13%

Base: total respondents, 2018 online survey

❋ Insights from Annual Telephone-Based Customer Surveys 2015-2018

UtilityPULSE conducts an annual telephone survey of Algoma Power customers using a consistent set of core questions and methodology. To gain more insight into customer needs, wants and expectations, the annual survey will contain supplemental questions.

The Fall 2018 telephone survey was derived from interviewing 400 residential and small commercial customers. The primary qualification for being interviewed is, the respondent is the bill payer. Timing for conducting the surveys in each of the years 2015-2018 was a 6-week period beginning the last week of September.

What follows are pertinent extractions of information derived from customer respondent telephone interviews. National benchmark numbers are derived from conducting interviews with bill-payers across Canada and with results weighted by population. The Ontario benchmark is also based on interviews with bill-payers throughout the province with results weighted by population.

Satisfaction, Bills & Blackouts

Electricity bill payers who are 'very or fairly' satisfied with…

	2018	2017	2016	2015	2014
Algoma Power	93%	88%	79%	92%	-
National	91%	90%	86%	89%	89%
Ontario	91%	85%	81%	86%	83%

Base: total respondents / (-) not a participant of the survey year

Percentage of Respondents indicating they had a Blackout or Outage problem in the last 12 months

	Algoma Power	National	Ontario
2018	57%	39%	44%
2017	61%	37%	38%
2016	45%	46%	46%
2015	50%	53%	51%

Base: total respondents / (-) not a participant of the survey year

Your LDC has a standard of reliability that meets your expectations

	Algoma Power	National	Ontario
2018	88%	88%	88%
2017	88%	88%	86%
2016	84%	86%	84%
2015	84%	87%	88%

Base: total respondents / (-) not a participant of the survey year

Percentage of Respondents indicating they had a Billing problem in the last 12 months

	Algoma Power	National	Ontario
2018	9%	9%	9%
2017	22%	12%	15%
2016	37%	15%	25%
2015	15%	9%	15%

Base: total respondents / (-) not a participant of the survey year

From the 2018 Annual Telephone-Based Customer Surveys:

Numbers at a Glance			
	Algoma Power	National	Ontario
Customer Satisfaction: Initial	93%	91%	91%
Customer Satisfaction: Post	92%	91%	89%
Communication Score	81%	--	79%
Convenience of Services Score	77%	--	79%
Customer Experience Performance Rating (CEPr)	85%	84%	83%
Customer Centric Engagement Index (CCEI)	84%	81%	80%
Credibility & Trust Index	84%	82%	81%

Base: total respondents

Supplemental Survey Questions

Algoma Power's customers' preferred or primary method for Algoma Power to contact them about billing issues are as follows:

Preferred method of communication to receive notice of a billing issue		
	Ontario LDCs	Algoma Power
Telephone	56%	75%
Voice Mail	2%	1%
Text	7%	4%
Email	34%	18%
Don't know	1%	2%

Base: An aggregate of 5,412 respondents from 2018 participating LDCs / total respondents from the local utility

Method of communication Customers prefer their LDC uses during an UNPLANNED OUTAGE		
	Ontario LDCs	**Algoma Power**
Recorded telephone message	34%	66%
Email notice	21%	11%
Posted on the utility's website	4%	2%
Social media	5%	2%
Local radio	5%	3%
Local TV	3%	1%
Text message	24%	12%
Alert on APP	3%	1%

Base: An aggregate of 5,812 respondents from 2018 participating LDCs / total respondents from the local utility

Method of communication Customers prefer their LDC uses about general news		
	Ontario LDCs	**Algoma Power**
Recorded telephone message	22%	44%
Email notice	40%	25%
Posted on the utility's website	7%	5%
Social media	6%	4%
Local radio	5%	4%
Local TV	5%	5%
Text message	9%	5%
Alert on APP	2%	0%

Base: An aggregate of 5,008 respondents from 2018 participating LDCs / total respondents from the local utility

Satisfaction with information provided		
Top 2 Boxes: 'very + fairly satisfied'	**Ontario LDCs**	**Algoma Power**
The amount of information available to you about energy conservation	82%	85%
The quality of information available when outages occur	73%	78%
The electricity safety education provided to the public	74%	79%
The timeliness and relevance of information for things such as planned outages, construction activity, tree trimming.	78%	91%

Base: An aggregate of 6,207 respondents from 2018 participating LDCs / total respondents from the local utility

Communication Score		
	Ontario LDCs	**Algoma Power**
Communication Score	79%	81%

Base: An aggregate of 6,207 respondents from 2018 participating LDCs / total respondents from the local utility

Access to services		
Top 2 Boxes: 'very + somewhat satisfied'	**Ontario LDCs**	**Algoma Power**
The availability of call-centre staff Monday to Friday	76%	81%
The 24/7 availability of system operators to respond to outages	77%	80%
The online self-serve options for managing your account	63%	52%
The online self-serve options for request services	56%	45%

Base: An aggregate of 6,207 respondents from 2018 participating LDCs / total respondents from the local utility |
Hours: Ontario LDCs 8:30 am to 4:30 pm, Algoma Power 8:00 am to 4:30 pm

Convenience of Services Score		
	Ontario LDCs	**Algoma Power**
Convenience of Services Score	79%	77%

Base: An aggregate of 6,207 respondents from 2018 participating LDCs / total respondents from the local utility

A focus on priorities can lower risk, increase efficiency and optimize resource utilization - resulting in faster deliveries of key requirements. Fall 2018 telephone survey respondents were asked to rate their priority level for each of the 12 following items:

Priority Planning within the next 5 years	
Top 2 Boxes: 'very high + high priority'	**Algoma Power**
Maintaining and upgrading equipment	87%
Reducing response times to outages	79%
Investing more in the electricity grid to reduce outages	76%
Investing more in tree trimming to help reduce the number of outages	75%
Investing in projects to reduce the environmental impact of the utility's operations	69%
Educating the public as it relates to electricity safety	68%
Educating customers about energy conservation	64%
Burying overhead wires	51%
Providing sponsorships to local community causes	49%
Developing a SMART phone application to allow you to view usage and pay your bill	36%
Providing more self-serve services on the website	22%
Making better use of social media (such as Twitter, Facebook, etc.)	20%

Base: total respondents

From the 2017 & 2016 Annual Telephone-Based Customer Surveys:

Recognizing technology plays an important role in achieving higher levels of service for customers and having the potential for making operations more efficient, in 2017 & 2016 Algoma Power included supplemental questions about the effect of technology on people's lives and about the importance of 10 potential technological enhancements to customer service.

The effect of technological changes on people's lives will lead to a future that is …					
Algoma Power	**Overall 2016**	**Overall 2017**	**Income: < $30k**	**Income: $30k < $75k**	**Income: $75k+**
Mostly better	49%	49%	43%	52%	56%
Mostly worse	7%	7%	7%	12%	8%
Neither	33%	29%	21%	25%	31%
Don't know	10%	14%	29%	10%	3%

The effect of technological changes on people's lives will lead to a future that is …					
Algoma Power	**Overall 2016**	**Overall 2017**	**Age: 18-34**	**Age: 35-54**	**Age: 55+**
Mostly better	49%	49%	67%	44%	48%
Mostly worse	7%	7%	11%	12%	7%
Neither	33%	29%	22%	35%	26%
Don't know	10%	14%	0%	6%	18%

Base: total respondents 2016, 2017

Importance of online access for the following features:			
Top 2 Boxes: 'very + somewhat important'	**Algoma Power 2016**	**Algoma Power 2017**	**UtilityPULSE Database 2017**
Reporting or inquiring about an issue	49%	69%	74%
Researching information about energy conservation	63%	74%	79%
Having a web chat feature on the website	27%	39%	51%
Automated alerts when electricity usage exceeds a prearranged threshold	52%	64%	72%
Review and pay your bill online (through utility's website)	59%	61%	69%
Power outage alerts	71%	81%	81%
Tools and calculators to help you manage your electricity consumption	50%	57%	68%
Comparison of your electricity consumption with your neighbours	38%	39%	51%
Automated alert to predict your upcoming bill	37%	47%	59%
Automated alert to remind you of your bill due date	36%	51%	61%

Base: total respondents Algoma Power 2016 & 2017 / 7,500 respondents from the 2017 UtilityPULSE Database

From the 2015 Annual Telephone-Based Customer Survey:

For 2015 the Algoma Power supplemental questions were about Outages and Outage Management. 84% of API telephone survey respondents agreed, API had a standard of reliability that meets their expectation. However, API wanted to know more:

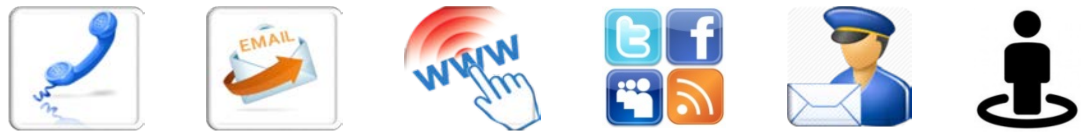
How many outages are acceptable over 12 months?		
	UtilityPULSE Database	Algoma Power
None	23%	13%
One	15%	6%
Two	26%	26%
Three	13%	18%
Four	5%	8%
Five or more	7%	13%
Don't Know	9%	17%

Base: An aggregate of 3,948 respondents from the 2015 participating LDCs / total respondents from the local utility

Reasonable amount of time for an unplanned outage?		
	UtilityPULSE Database	Algoma Power
Less than 15 minutes	14%	0%
16-30 minutes	15%	11%
31-60 minutes	13%	7%
1 to 2 hours	29%	34%
3 to 5 hours	13%	22%
6 to 12 hours	5%	8%
More than 12	3%	3%
Don't Know	8%	13%

Base: An aggregate of 3,948 respondents from the 2015 participating LDCs / total respondents from the local utility

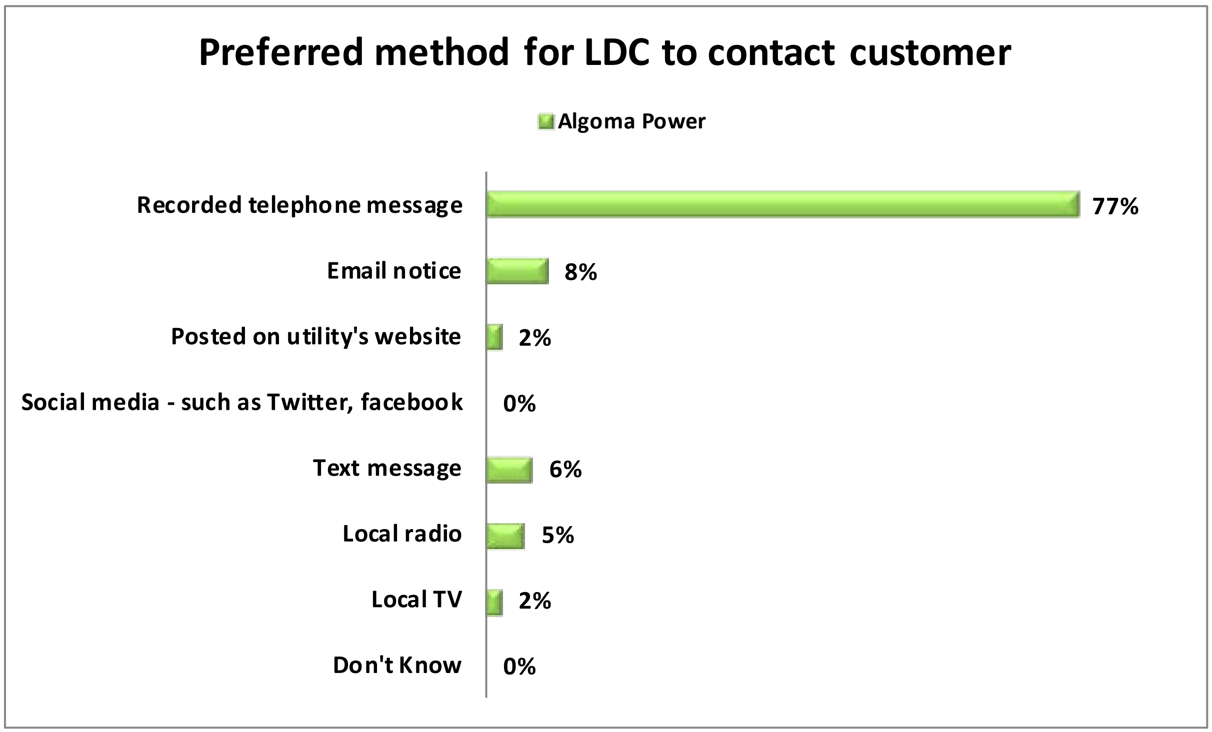
When contacting API about an outage, customer respondents overwhelmingly preferred to contact API via telephone.



	Telephone	Email	Utility Website	Social Media	Mail	In Person
Ontario LDCs	84%	5%	2%	1%	0%	0%
Algoma Power	90%	4%	1%	2%	0%	3%

Base: An aggregate of 3,948 respondents from the 2015 participating LDCs / total respondents from the local utility

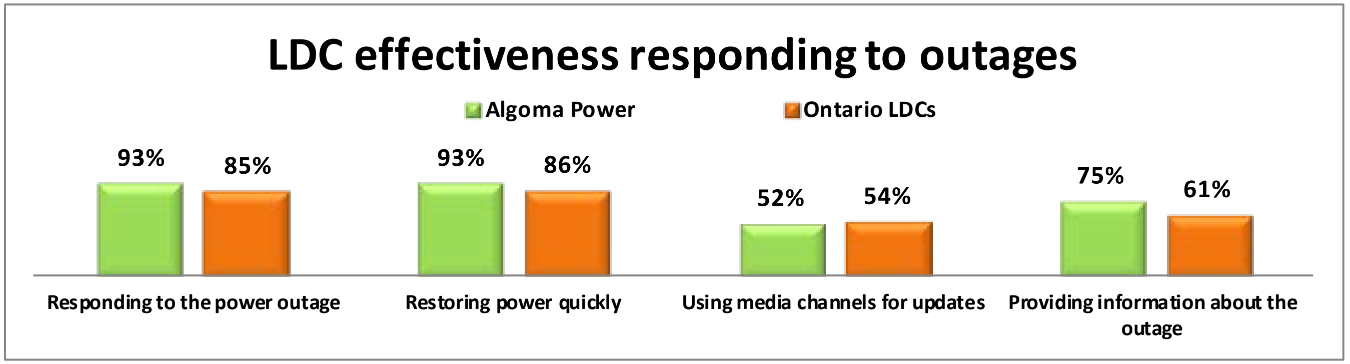
From a pro-active point-of-view what might be the preferred method for contacting customers about an unplanned outage?



Base: total respondents

LDC effectiveness responding to outages		
	Ontario LDCs	**Algoma Power**
Responding to the power outage	85%	93%
Restoring power quickly	86%	93%
Using media channels for updates	54%	52%
Providing information about the outage	61%	75%

Base: An aggregate of 3,948 respondents from the 2015 participating LDCs / total respondents from the local utility



Base: An aggregate of 3,948 respondents from the 2015 participating LDCs / total respondents from the local utility

Planned Outages

Speaking in terms of "planned" outages for things such as service maintenance or repair work, customers understand this to be a controlled event and therefore expect their LDC to be able to communicate full details about the planned outage, i.e., such as start time, duration, and service areas to be affected. The more the customer is informed, the better they control the impact of a planned outage on their day to day functions, thereby minimizing the likelihood for a situation of inconvenience to arise.

Planned Outages	
Top 2 Boxes: 'agree strongly + agree somewhat'	**Algoma Power**
Provides adequate notice of planned outages	92%
Completes the work within the stated time periods	92%
Is effective in their communications about planned outages	93%

Base: total respondents

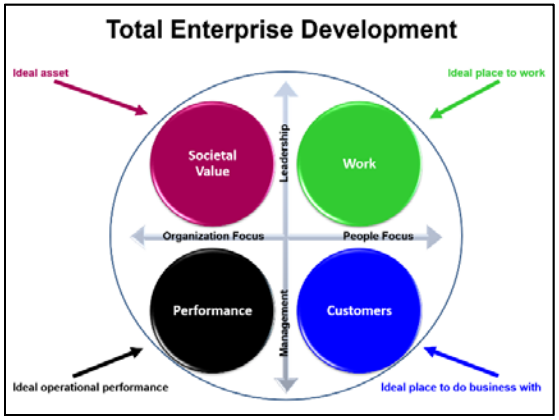
Planned outages - Advance Notice:

Algoma Power customer respondents were asked about the amount of time which would be deemed as adequate notice in advance of a planned outage:

- 38% felt 2 to 3 days advance notice would suffice
- 12% felt 4 to 7 days advance notice would be required
- 50% felt 1 week would be ample notice time in advance of a planned outage.

Base: total respondents

❋ Managing the whole enterprise from a Customer's perspective



For the 20 consecutive years, UtilityPULSE has conducted its Annual Customer Satisfaction Survey for LDC clients in Ontario, the number one suggestion made by customer respondents to improve service was "reduce the price." Any other subject is a distant second.

Customer respondents view the performance of their LDC primarily through the lens of costs. Given the emotional roller-coaster LDC customers have gone through over the past few years it is no wonder why customers see costs first and value second. In 2015, 2016 and the early part of 2017, for most residential and small commercial customers, the cost increases for the energy side of their bill could not be reconciled with what was happening in their lives, e.g., 0-2% salary increases, 2% inflation costs, etc.

Successful LDCs and other enterprises know to keep costs low the total enterprise must be performing at a high level. That is, employees need to be engaged because when they are not, increased costs and poor performance can be the result. Customers need to be engaged, in particular, feel they are valued, if not complaints go up and there is a cost increase to handle the additional volume. Operationally speaking the LDC has to perform at least to the standards in the industry. Also, the LDC has to be seen as socially responsible and as a valuable asset to its owners and the customers it serves.

The UtilityPULSE annual telephone surveys contain various attributes when grouped give some insight into how customers perceive the successfulness of the enterprise. While many attributes could be measured which would provide some insight into Algoma Power's success, the following represents how a customer respondent could look at their LDC. Customer respondents were asked to what degree they would agree or disagree with the following statements apply to Algoma Power.

Total Enterprise Development	
Ideal place to do business with	**Algoma Power**
Provides information to help customers reduce electricity costs	80%
Pro-active in communicating issues that affect customers	84%
Quickly deals with issues that affect customers	87%
Cost of electricity is reasonable when compared to other utilities	59%
Provides good value for your money	73%

Base: total respondents with an opinion, Fall 2018

Total Enterprise Development	
Ideal place to work	**Algoma Power**
Deals professionally with customers problems	88%
Customer-focused and treats customers as if they're valued	85%
Makes electricity safety a top priority for employees and contractors	90%
Adapts well to changes in customer expectations	81%

Base: total respondents with an opinion, Fall 2018

Total Enterprise Development	
Ideal operational performance	**Algoma Power**
Operates a cost-effective electricity system	68%
Efficiently manages the electricity system	85%
Delivers on its service commitments to customers	87%
Quickly handles outages and restores power	89%

Base: total respondents with an opinion, Fall 2018

Total Enterprise Development	
Ideal asset	**Algoma Power**
Is a trusted and trustworthy company	89%
Is a socially responsible company	86%
Overall the utility provides excellent quality services	88%
A leader in promoting energy conservation	77%

Base: total respondents with an opinion, Fall 2018

Statistically the results shown above are the same as the Fall 2018 LDC average which is based on interviews with 2,328 customer respondents. Algoma Power, like many LDCs in Ontario, struggle with the comparison of costs with other non-electricity utilities and the perception of value. Based on our years of research, the low perception of values is an industry wide problem.

Based on the results from customer respondents, Algoma Power is a highly rated electric utility.

❋ Wisdom from Customers:

An important feature of Algoma Power's seven online surveys, (except Chapter survey #2) was to provide every respondent with the opportunity to be contacted by an Algoma Power representative; this was featured through the "Hot Alert" questions.

- Only 17 customer respondents asked to be contacted. Follow-up subjects included: billing, low-income assistance, and general customer service.

Customers want their voice to be heard, they do have ideas, and they want to be respected. With this in mind, another feature of Algoma Power's online surveys, (except Chapter survey #2), was to provide customer respondents an open space to provide comments; this was featured through two closing questions, the first being "Wisdom from Customers." [Q: We are always looking for ways to reduce costs to safely and reliably deliver electricity. What ideas do you have which might help reduce costs without compromising performance?]

- In total 121 customer respondents provided their "wisdom."

Comments received were sorted into 5 categories: Customers, Staff, Costs, Operations, Other. Entries such as: none, no, not at this time, don't know were removed.

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Topic: Customers

- A door to door to show people things they can do in their own home
- Educational info to customer, what to report b/4 it becomes a real issue, preventive versus reactive.
- Help home owners become more efficient using power and encouraging/providing incentive/partnering with government to include more sustainable power sources such as solar power for customers who have a high demand in order to reduce costs which can make a region more attractive for people to live and could promote more business in rural areas. Overall it can improve peoples' quality of life and livelihood.
- Help to educate people and how to reduce their amount of electricity. This should include manufacturers of appliances etc. Also look at company salaries and have the highest employee only get 10 % more than the lowest employee. Reward better ideas from employees with monetary awards and/or training or scholarships to local colleges and universities.

- Letting customers know if there are any cash back that the government might offer to the customer or Algoma Power. giving out information on how to save energy
- More discounts for everyone. Have your workers call you when they are doing the tree trimmings before so solar lights can be removed before they come, so they don't get broken in the process.
- more flexible payment plans and being able to pay cash at the office.
- More incentives for upgrading appliances
- More use of social media (especially Twitter) to advise of power outages and estimated time of power resumption. Up to date maps on website to show extent of power outages
- providing programmable thermostats
- Really get into energy efficiency workshops and information. Look outside the box for future solutions. Run that lottery among college and universe students and your employees that I mentioned in an earlier survey.
- Residential customers especially seniors on a fixed budget should continue or be approached individually about your rate assistance program think many do not know about it.
- unplug-tv, computer when not in use woodstove
- Use website, FB, text messages to communicate power outages planned and unplanned when arise would save a lot of calls into that one number.

Topic: Staff

- Cut management positions.
- Cut upper management positions. These are not needed. Every business has too many management which is not cost effective.
- During a power outage I do not have access to the internet to provide or receive information about outages. I use the telephone and operators are very helpful and kind.
- Have staff on call for emergency operations.

- I am not sure you need full-time office staff on site...many companies are reducing staff and having shorten hours
- keep staff up to date regarding safe work habits and danger conditions regarding lines
- Keep the after-hours staff up to date on planned power outages. I called and the staff I spoke with was very frustrated that they didn't know about any planned outages.
- listen to your employees in the field as they are the most valuable tools in the tool box.
- more personnel less remote sensing
- Not sure what people make for wages but in general when looking at wages from most industries a lot of people on the sunshine list are in the power business. Even the common secretary should not be over a $100,000. No question they work hard but......
- Stop paying the upper management such extremely high wages
- turn vehicles off when not using them.

Topic: Costs

- Algoma Power charges the highest distribution rates. Algoma Power should find ways to minimize its costs and Seasonal customers seem to be charged very high amounts to provide electricity to their properties.
- As a seasonal customer with very low usage, I feel completely and utterly ripped off by Algoma Power. I am subsidizing my year-round neighbours - many of whom can afford to go south for the winter.
- base delivery charge more in line with use the flat rate concept makes no sense in my mind
- delivery charges are rather high
- Delivery charges are ridiculously high. At times more than 90% of my bill and only as low as 50%
- Delivery charges need to be reduced very high compared to other companies
- delivery fees seem to be very high
- Eliminate Global Adjustment Cost buried in the cost of power.

- Find new efficiencies with existing resources. As it stands right now, my delivery charges are higher than the charges for the electricity that I use. There is no other service I can think of where the delivery charges are as high, or higher than the goods/service being delivered.
- For seasonal customers the delivery charges are way to high and a not in tune with time of use. To clarify, the delivery charge and time of use rates should be in line and not standard across all time of use rates.
- get rid of delivery charge
- get rid of the delivery charge
- I am new to this, delivery charges on top of electricity charges, I along with others don't understand why the delivery charges are higher than consumption charges, think this is a money grab and a poor one at that, why not reduce the bonuses of CEO’s and upper management to reduce these costs and make your customers think that you actually care about them. We do everything we can to reduce out electric use, but we still get nailed with this high delivery cost.
- I don’t really know how you can reduce costs without compromising performance. Everything costs money. I just don’t want higher bills.
- I have no control over what you do or don't do. You tell me what I owe, and I have no choice but to pay it.
- I have no ideas but do find the delivery cost very expensive
- Increasing the cost of power in rural areas really hits the bill. My power consumption is lower than the delivery which is very difficult for a single income home.
- less expensive delivery charges
- look at service charge. User pay. match names on rates to names on bill.
- Look into reducing delivery costs.
- Lower the delivery charge. Especially on seasonal accounts.
- reduce delivery charge
- Reduce overhead costs and unnecessary expenditures
- Reduce overhead costs, eliminate unnecessary expenditures
- Reduce staff, reduce rates

- Reduce the cost of delivery to rural customers so it's not more that actual electricity use.
- Reduce the delivery charges. I pay a lot for use of my cottage in the summer and it is hardly used the rest of the year. However, the delivery charge is out of proportion to the amount of power I use.
- Reducing the rate of delivery charge
- Re-evaluate the delivery charge rate
- Remove the Delivery Charge for months where there is zero electricity used
- We are on a fixed income, so we cannot agree with an increase in our power bills.
- We pay well over 300 bucks a month...
- Why do I pay the highest rate in Ontario?

Topic: Operations

- As mentioned in my comments in Survey #7, hazard tree removal on private property between your pole and our meter.
- buy all office equipment and products in bulk and when on sale, people are only as efficient and as good as their tools
- Can't think of anything, but priority is reliable service, communication with customers, restoration of service.
- Do more brushing along your power lines to help reduce fallen trees across your lines.
- Do more powerline monitoring of trees that are too close to power lines
- Get rid of paper use.
- Hazard tree removal from private property that could interfere with the power line from your pole to our meter.
- I strongly believe that the system is too inter connected and should have more "stations" that can stand alone in case of emergencies. You are a corporation and you seem think everyone lives in an urban area.
- I think the tree cutting was a good idea, but too extreme.
- If automate more use website and FB have aps etc. It will save you staff time, so its a net savings once done.

- Install new Electricity Metres
- Make better use of time and equipment   E.g. If one trip could be used to assess and repair rather than sending a smaller vehicle with one employee first and then sending the larger truck in for repairs after, especially when it is a fairly long distance.
- More brushing along the power lines.
- More brushing on the power lines
- More care in using contract power line clearing crews, actual case - a crew of native workers when their foreman tried to get them to produce, they hollered "racism" and threatened to get the foreman fired. From thereon the foreman sat in the truck and did crossword puzzles.
- More routine line cutting would help with reliability
- more tree trimming
- need to be more proactive with maintenance of power lines and vegetation. They were here for an issue said our lines need an upgrade had the lines down, but did not upgrade them
- Offering incentive to the user who wants to produce power and sell excess to the grid.
- On new installs where possible bury the lines to prevent weather related issues
- Put lines underground
- Regular maintenance of all equipment instead of waiting for a breakdown
- Remove dead trees that are over the 15 ft.
- routine more frequent checking of lines don't wait for a customer to complain
- Should clear cut every tree for a mile in every direction from any power line.
- Start developing underground wiring to avoid damage from bad weather conditions which are becoming more frequent.
- switch to underground cable. On long-term it will be cheaper
- Take out smart meters.. not good for health.. and my bill went up a lot

- The cost Algoma Power has paid and is paying to clear trees from around the power lines must be in excess. So much of this was unnecessary and just plain dumb. Your contractors would spend days cutting down apple trees and scrub brush, that could in NO WAY ever take down a power line. So much money was money was wasted this year, just because the planners did not use their brains. Not impressed at all.
- tree removal beyond specified limit upon landowner request
- tree trimming
- tree trimming program
- Utilizing underground cables to avoid weather problems.
- Vegetation brush control give landowners the option of doing the work and getting compensation rather than paying a 3rd party contractor. Brush removal included on our road removing many heritage apple trees that in no way would reach hydro lines height and contributed fruit for decades...sad situation...landowners would of recognized these trees as apple trees and left them??
- underground lines
- Underground services where possible
- underground wiring in areas of high concern, regulatory pressure on OEB on behalf of rural customers

Topic: Other

- Would need a breakdown of where you are spending our money.
- All good
- API is doing a great job
- Charge other larger areas more than the smaller communities that don’t use things such as air conditioners and when we have all the dams on our waterways cities are paying less for more consumption we should get a break living in the north
- Don't feel I am knowledgeable enough in electricity to offer an opinion

- Encourage governments to promote energy efficiency in new construction and in renovations. Create an online program that will show residents and businesses what their costs will be based on square footage, number of openings and layout & orientation on site.
- Encourage the use of renewable resources.
- I leave it in your capable hands
- I think Algoma Power Inc is doing a great job and I support their new ideas in this avenue
- I will continue to support API's direction
- Invest in more green energy initiatives and reward those individuals who do the same
- Keep our generated power local!
- Les technology related to billing.
- Maintain building code but why build new or renovate.
- Monitor status of smart meters to determine if power on or off. Could be part of smartphone app. Do hours for "on peak" billing still apply i.e. peak limiting or is this just a way to charge more?
- My residence is in a location that when the power is out I do not have internet service and often no cell phone coverage.
- Pleased with the way it is now...noticed a big difference over the past few years.
- Shut down the wind farms.
- Think outside the box.
- time of use doesn’t reflect requirements of people in the north
- unfortunately this is not my area of knowledge I leave it in your capable hands
- way more solar power for homes
- Would need a detailed breakdown of where you spend our money to comment, right?
- You guys are doing a great job. Could not tell you how to cut costs.
- Your company seems to be doing a good job.

❋ Additional Comments from Customers:

As outlined in the previous section, customer respondents were provided an open space to provide comments; this was featured through two closing questions (the first discussed in the previous section "Wisdom from Customers") and the second being, "Make Your Voice Count." The primary purpose of this second and final open space for customer respondents was to afford them the opportunity to provide comments about Algoma Power and/or Algoma Power's COS rate application. [Q: Do you have any additional comments about Algoma Power or its Cost of Service Rate Application?]

- **General Comments from customer respondents: 82 comments**

An additional feature of Algoma Power's seven online surveys, (except Chapter Survey #2) was to provide every respondent with the opportunity to be notified of any future public meetings regarding their COS rate application.

- Only 22 customer respondents requested to be notified.

A review of the 82 general comments from customer respondents covered a broad range of topics. Comments received were sorted into 5 categories: Customers, Staff, Costs, Operations, Other. Entries such as: none, no, not at this time, don't know were removed.

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Topic: Customers

- Appreciate the help for small business on Energy reduction grant.
- give us a cold weather discount for the colder months
- looking at decreasing peek hours and/or re-evaluating these hours and letting customers know by e-mail or mail on how to save on their bill or sending out quarterly reminders about the time when it is peek hours or not.
- Maybe sending out a recording as to why the power is out & an expected timeframe for power to come back on
- Planned power outages currently are only communicated via telephone think the FB or internet/website should include a list of upcoming planned power outages.
- Should show power outages on their website. It will help everyone not to stay in line over 20 minutes to speak with someone from the customer service to figure it out when the problem is solved
- The notification of planned outages is excellent

Topic: Staff

- At least until the baby boomers are dead please keep counter staff and real people answering the phones. Also train your staff to be able to do multiple tasks so they do not become obsolete. You will gain their loyalty and in return your old customers will be happier.
- doing a great job, customer service is stellar
- Great staff
- I like Algoma Power, whenever I have had an issue customer service has always resolved it quickly and been very polite
- love that you are on Facebook etc.
- Thank you
- Thank you for your service
- Thanks
- Thanks for your service. You do good work.
- You do a fantastic job!
- Your emergency crews are remarkable. One of the few areas where I see safety training, pride in a job well done and genuine concern for each & every customer.

Topic: Costs

- Algoma Power has the highest electrical rates in Ontario and should look at more ways to keep costs at a minimum to its customers.
- Always looking to lower hydro bill
- As a seasonal customer I have difficulty understanding delivery cost when little or no power is used
- Cheaper Rates
- cold weather discount for colder months

- Delivery Charges are bullshit.
- delivery charges are higher than consumption
- Delivery charges seem for seasonal customers esp when usage is zero
- Delivery costs too high…more than my power bill.
- delivery fee is ridiculously high
- delivery fees are outrageous
- Don't agree with my seasonal residence costs are higher than a non-seasonal place next door to mine .
- Help for seasonal property owners and the high distribution charges. Having these charges lowered may increase the number of properties being built in low density areas of Northern Ontario.
- I do not think the paying customers should have to contribute to cover loss from unpaid bills or disconnections,
- I find, as do my family and friends, that the cost of delivery and other fees are VERY high in comparison to my power bill which is often below $100. I do my best to conserve power and make use of peak hours but still a large portion of my bill is going towards the company and not a reflection of how much power I use. I needs to be more reflective of the portion of power I use, I conserve and have a small bill and yet nearly half that bill is not for my power consumption.
- I would like to see a decrease in the delivery charges
- It is to high
- Its way too high I can’t afford 300 a month
- Keep the cost down!
- less delivery charges
- Lower your rates. Especially the delivery fee.
- My feeling is the rate seems on the high side, but without examining the financial statements and the operational activity and related cost structures, I am relying on the management to operate in the best interest of the consumer.
- Myself and everyone I talk to all agree that the delivery charges are too high. Example, my garage on a lot next to me used 70 cents worth of power. The "delivery charges" were $53.22. Ridiculous no??

- No fare that Seasonal residence pay way more.
- Please continue to look into ways to reduce costs for rural residential customers. Thank you.
- The delivery cost for electricity is too expensive
- The delivery rate is over priced.
- to many additional fees
- Unable to answer question regarding disconnecting power to people unable to pay their bill. I feel there are so many reasons people might be unable to pay and each situation needs to be looked at individually. Therefore, not sure if I would be willing to subsidize more.
- We should not have to pay if other people do not pay their bills.
- why do seasonal residents pay more than all season?
- Why is delivery service so high compare to the amount of electricity used?

Topic: Operations

- Brush removal that was done in our rural area was overkill way over existing fence lines into fields over split cedar fencing and heritage apple trees.....personally do not understand the reasoning behind it. Shrubs and vegetation along our road provided habitat and a windbreak for plowed fields preventing erosion in the spring and snow break in the winter for the road. We are left with a completely denuded bare shoulder. In the Sault trees grow right under and close to touching lines more consideration is given to maintaining the trees and shrubs and their value.
- Do you test smart meters for accuracy?
- How reliable are these smart meters???
- I believe our cost of electricity is high enough, I do understand that sometimes increases are necessary, but I think that expenditures and cost reductions should be made where possible before increases happen. Ex. The office doesn't need a $500 chair when a $100 chair will do (and last just as long). Save money on office supplies etc.
- I feel we are having more and more unexpected power outages. Sometimes these can be quite lengthy.

- I’ve never agreed with smart meters. Most people except for retirees can afford the time to use power at the cheaper times of use. The rest of society with families can’t afford to do this.
- re: line clearing - In our area I have seen some brutal clearing. I personally saw low growing vegetation cut and destroyed that is an important part of the ecology. Examples: a very old patch of lady slippers (that I have seen and looked at for over 20 years) and of course milkweed. Without knowing how these plants could possibly affect power lines, couldn't some method less slash and destroy be employed?
- So thankful for the guys that restore power when it goes out. They are usually out it the worst of the weather and it is appreciated.

Topic: Other

- API is doing a great job
- Compared to when I first moved here I experience less frequent and shorter power outages and interruptions.
- Continue to keep costs as low and reasonable as possible. Contrary to what Mike Harris did when he was premier and the McGuinty/Wynne premiers did, our electricity IS NOT and SHOULD NOT be a commodity like pork bellies, or wheat. Sir Adam Beck said many years ago when he brought Niagara on line...."Electricity to all Ontario at cost"!! The politicians have messed this file up big time. Electricity is an essential service! Read what Bonnie Lysyk Auditor General said about our electricity costs compared to the rest of Canada. I could go on but I'll stop now as I expect you get my drift.
- Cost of power is competitive extremely high compared to other areas. Thank you green power enthusiast
- costs of delinquent accounts should be OEB or governmental responsibility as maintaining connection is mandated by same.
- Did not know I was paying for other people to not pay their Bills. Seems like an extra knife in the back since I struggle but pay my Bills. Maybe find another way to cover the cost of delinquency rather than punishing the rest of us.
- Good, reliable service
- Hold a lottery to ask university students to come up with future solution for our aging systems for 1 million dollars.
- I am a satisfied customer
- I am pleased with service and cost of service.
- I believe electricity is well worth the cost. I would not be without it. I however continue to try to use less.

- I feel I do not have the knowledge base to answer several of the questions.
- I feel the cost for power is reasonable for the service I receive.
- I feel they are to high in cost...room for improvement
- I pay for my power and feel I should not be responsible for other people's bill or companies.
- I still don't understand it
- I think that Algoma Power should be able to provide customers with a quote on adding a service box and line. We were told they could not until after the structure was put up. But not knowing this cost does not allow us to make decisions.
- I wish we could go back to a time when Great lakes power provided power, before Mike Harris, when we didn't have to pay for the transportation of power from Southern Ontario when in fact most of the power comes from here.
- is time of usage a real thing or is it a scam?
- No comment about the Cost of Service Rate Application. I have invested in Algoma Power and the dividend helps pay my power bill. I like this feature. I have also invested in Brookfield Renewable and their dividend also helps pay my power bill.
- Perhaps all new construction should require back up generators using propane and/or natural gas???
- Personally, I feel Algoma Power is a pretty good company. I like the safety procedures and training I see among your emergency employees who should be getting paid more than any office worker. Of course, I want better service at lower costs, but I know that is not possible. I think real deep down every conservation education is our only hope with carrots as incentives not to improve efficiency not penalties.
- With the surplus of available power production, why does Ont. have such high power costs????
- You spend HOW MUCH on the vegetation program??????? YET, refuse to compensate us for our loss of property value?????? Time to fork some dough over for raping my land and destroying my life.

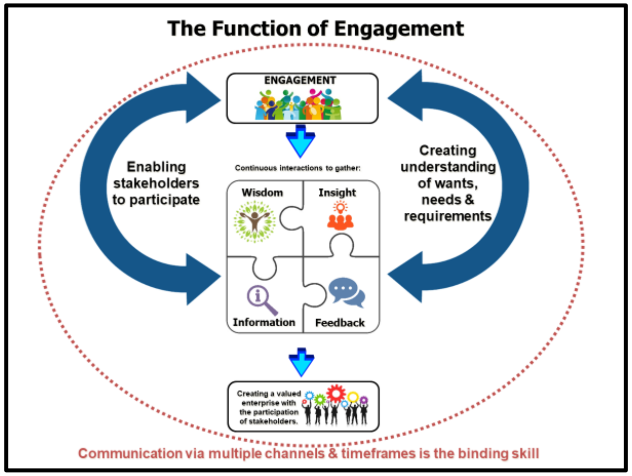
❋ What is Taking A.I.M. (Applied Insights Methodology)

The purpose of engaging customers is to gather usable findings which help the LDC meet the needs and requirements of customers and other stakeholders while accelerating movement towards becoming a more effective and efficient organization with high levels of customer affinity. The goal is to ensure there is alignment between LDC plans and customer needs and expectations. The function of customer engagement is to create an understanding of wants, needs, and requirements. The key to getting meaningful input is to ensure customer respondents are enabled via multiple opinion & views methodologies.

An output, from Taking A.I.M. for Algoma Power is the production of this report, which we like to call "Algoma Power's Book on Customer Engagement."

Unlike a single online or telephone survey, A.I.M. utilizes a multiple touch-point design to entice participation by customer-respondents who, like just about everyone in Ontario, is time-pressed. This multiple touch-point design helps to:

1- Keep the time requirements short (long surveys have a high abandon rate)
2- Identify, for the LDC, customer-respondent wants, needs and requirements
3- Clarify customer-respondent priorities
4- Identify the level of support for various capital and operational changes, including the associated costs.



The Taking A.I.M. process helps the LDC to answer the following questions:

1- What are the customer-engagement (CE) activities that we have been doing?
2- What have we learned from those CE activities?
3- When going forward with a COS application which CE activities:
    a. Are best done with internal resources?
    b. Need to be enhanced?
    c. Should be completed by a 3rd party?
4- What are customers saying about what should be priorities?
5- What are the challenges the LDC has identified for producing a successful COS application?
6- What level of community outreach can be achieved in the allocated timelines?
7- What additional value, or synergy, can be achieved through the activities of producing a successful COS application?

One way to improve the effectiveness of various customer engagement activities is to determine the type of information the LDC is trying to gather.

Embedded in the Taking A.I.M. model are five levels of engagement.

For our purposes, the first four levels are: Giving/Getting Information; Gathering Feedback; Capturing Insights; and, Gaining Wisdom from respondents.

Understanding the type of feedback which is desired by the LDC helps ensure any survey work which is done, via telephone or online, is both effective and efficient for customer respondents.

By understanding the type of feedback from customer-respondents the LDC desires, a 5-phase project plan is then developed.

Taking A.I.M. Project Phases

Phase 1: Planning and Preparation (Partially done and is well underway)

- Conduct a review of current CE activities
- Identify ways to get the best from internal resources
- Project administration requirements

Phase 2: Customer Engagement Activities - Fieldwork

- Operationalize CE activities

Phase 2: Online DSP

- Seven online survey "rounds" [we call them Chapters] soliciting feedback and comment re: CE/DSP

Phase 2: Telephone Survey

- Capitalize on the Fall 2018 telephone survey of Algoma Power customers

Phase 2: Customer & Community Outreach (this is handled by API personnel)

- Making the best use of activities

Phase 2: Support Activities

- Project administration
- Identify additional sources of data or information which can be used to help validate findings from Algoma Power surveys, e.g., UtilityPULSE database, Ontario LDC benchmark
- Embed a “Hot Alert” function in every “Chapter” survey, i.e., give respondents the opportunity to speak to someone at Algoma Power to voice their concerns or to have a problem solved
- Monitor and report on progress

Phase 3: Discussion, Analysis and Reporting for Internal Use (on a per “round” basis”)

- Review findings with internal LDC personnel to help the alignment of plans

Phase 4: Report Development for COS/DSP

- Survey data analyzed and reported in useable formats
- Provide 3rd party input into the completion of Appendix 2-AC

Phase 5: Post Project Review & Additional Recommendations

- Lessons learned
- Getting the most from the AIM

To further simplify and integrate various customer engagement online activities, four survey branding elements are used. These branding elements are used as visual cues for customer respondents as they relate to the purpose of their participation. For example, the branding element “Make Your Voice Count” was used on Algoma Power’s Home page as a link to the online surveys, and to the home screen for various surveys. Individual questions within those surveys would also use the branding elements.

Taking A.I.M. the Online Survey Strategy

UtilityPULSE has been conducting customer research for Ontario's LDC community for over 20 years. Based on this experience we have learned:

1- Long surveys (from a time perspective) have a high abandon rate. It is for this reason the "long" survey is broken down into several smaller surveys in the Taking A.I.M. methodology.

2- Respondents are interested in giving feedback in the subject areas they are interested in, which, in turn, contributes to higher levels of "Don't know" selections. Each of the Taking A.I.M. online surveys, which we call "chapters" has a different subject focus.

3- Online surveys such as COS/DSP which ask difficult questions that have complicated answers, some individual survey questions as a consequence require an extensive amount of reading. Question design and scaling are impacted.

4- The sequence, and timing of early chapter surveys provide information which feeds into later chapter surveys.

5- Question design for online should mimic question design found in other Algoma Power research, for example, telephone survey. This reduces the impact of one of the variables which can cause differences in findings.

6- Decisions are not made rationally they are made emotionally by human beings.

7- While different survey methods can produce different results, having consistency of question design, across multiple platforms, reduces one of the variables which can produce different outcomes.

Each of the surveys has a different purpose and when combined become a wider story of gathering wisdom, information, feedback and insights from customer respondents. The mission and theme for each survey:

Chapter Survey	Primary Theme
Chapter Survey 1 *"About your Algoma Power"*	Wisdom from Customers
Chapter Survey 2 *"How the electricity industry works and Algoma Power's role in it"*	Test your knowledge
Chapter Survey 3 *"Help Algoma Power understand our customer's priorities"*	Make Your Voice Count
Chapter Survey 4 *"Getting customer insights about billing and outages"*	Make Your Voice Count
Chapter Survey 5 *"Help us prioritize capital investments in the electricity network"*	Could You Help Us Decide
Chapter Survey 6 *"Gathering insights about customer care operations"*	Could You Help Us Decide
Chapter Survey 7 *"Help us determine which capital investments and operational changes you can support"*	Make Your Voice Count

Methodology

The 2018 findings in this report are based on telephone interviews conducted for Simul Corp. / UtilityPULSE by Logit Group between September 24 - October 27, 2018, with 401 respondents who pay or look after the electricity bills from a list of residential and small and medium-sized business customers supplied by Algoma Power.

The sample of phone numbers chosen was drawn randomly to ensure each business or residential phone number on the list had an equal chance of being included in the poll.

The sample was stratified so that 85% of the interviews were conducted with residential customers and 15% with commercial customers.

In sampling theory, in 19 cases out of 20 (95% of polls in other words), the results based on a random sample of 401 residential and commercial customers will differ by no more than ±4.89 percentage points where opinion is evenly split.

The margin of error for the sub-samples is larger and should be used as directional information only. However, the directional information may have more meaning if historical data and/or Ontario benchmark data shows similar results.

Online Surveys:

In order to write a "book" on customer engagement for Algoma Power, seven (7) customized "chapters," or surveys were developed. Each survey had a different theme, and each survey offered the respondent an opportunity to have someone from Algoma Power contact them, thereby adding an interactive element to the survey.

Customers were invited to participate in the online surveys via advertising efforts, social media messaging, home page website profile, and IVR calls. Participants were given the opportunity to complete as few or as many of the "chapters" they wished to provide feedback. Participation ranged from a low of 117 to a high of 195 completed surveys. In total, 264 customers respondent to 1 or more of the 7 surveys.

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UtilityPULSE

A Division of Simul Corporation

TAKING A.I.M.
(Applied Insights Methodology)

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All comments and questions should be addressed to:

Sid Ridgley, Simul Corporation
UtilityPULSE division
Tel: 1-905-895-7900
email: sridgley@simulcorp.com

Appendix 1C

Algoma Power Inc.

2020 Cost of Service

EB-2019-0019

File Number:	EB-2019-0019
Exhibit:	1
Tab:	
Schedule:	
Page:	
Date:	17-May-19

Appendix 2-A
List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts) new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified, as well being clearly documented in the appropriate sections of the application.

Additional requests may be added by copying and pasting blank input rows, as needed.

If additional requests arise, or requested approvals are removed, during the processing of the application, the distributor should update this list.

Algoma Power Inc. is seeking the following approvals in this application:

1		Approval to charge distribution rates effective January 1, 2020 to recover a base revenue requirement of $25,885,176, which includes a revenue deficiency of $2,192,853 as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8
2		Approval of the 2020 RRRP Adjustment Factor and the 2020 RRRP Funding amount payable to API, as described in Exhibit 8
3		Approval to adjust the Retail Transmission Rates – Network and Connection as calculated in Exhibit 8
4		Approval of the proposed loss factors as calculated in Exhibit 8
5		Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the Board Decision and Order in the matter of EB-2018-0294
6		Approval of the Distribution System Plan included in Exhibit 2

7		Approval of the rate riders for disposition of the Deferral and Variance Accounts, including LRAMVA, as detailed in Exhibit 9
8		Approval for Advanced Capital Module (“ACM”) treatment of the 2021 Echo River TS Project and the 2022 Sault Facility Project, as described in Exhibit 2 and the DSP
9		Approval of API’s proposed approach for ACM cost recovery in consideration of the RRRP framework, as detailed in Section 1.3.5
10		Such other approvals that API may request and that the OEB accepts
11		**(Preliminary Issue)** Approval of an amendment of API’s electricity distribution licence (EB-2009-0072) to extend the expiry date of certain Distribution System Code and Standard Service Supply Code exemptions to December 31, 2024, as detailed in Section 1.3.6
12		**(Preliminary Issue)** Approval of API’s methodology for allocating costs attributable to the Dubreuilville service area, as summarized in Section 1.3.7
13		**(Preliminary Issue)** Approval of API’s methodologies with respect to ongoing disposition of the Interim Licence Deferral account and with respect to recovery of costs recorded in the Transaction and Integration Costs Deferral Account, both in relation to the Dubreuilville service area, as summarized in Section 1.3.7
14		**(Preliminary Issue)** Approval, on an interim basis, to continue charging Seasonal rate class customers a rate rider of $0.0307/kWh related to the Disposition of Account 1574 that would otherwise expire on June 30, 2019, pending the OEB’s determination on further disposition of the residual balance in this account, as summarized in Section 1.3.8

Appendix 1D

Algoma Power Inc.

2020 Cost of Service

EB-2019-0019

STATEMENT OF CERTIFICATION

As Vice President Finance and Chief Financial Officer of Algoma Power Inc., I certify that, to the best of my knowledge, the evidence filed in this Application is accurate, complete, and consistent with the Ontario Energy Board's Filing Requirements for Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications, issued on July 12, 2018.

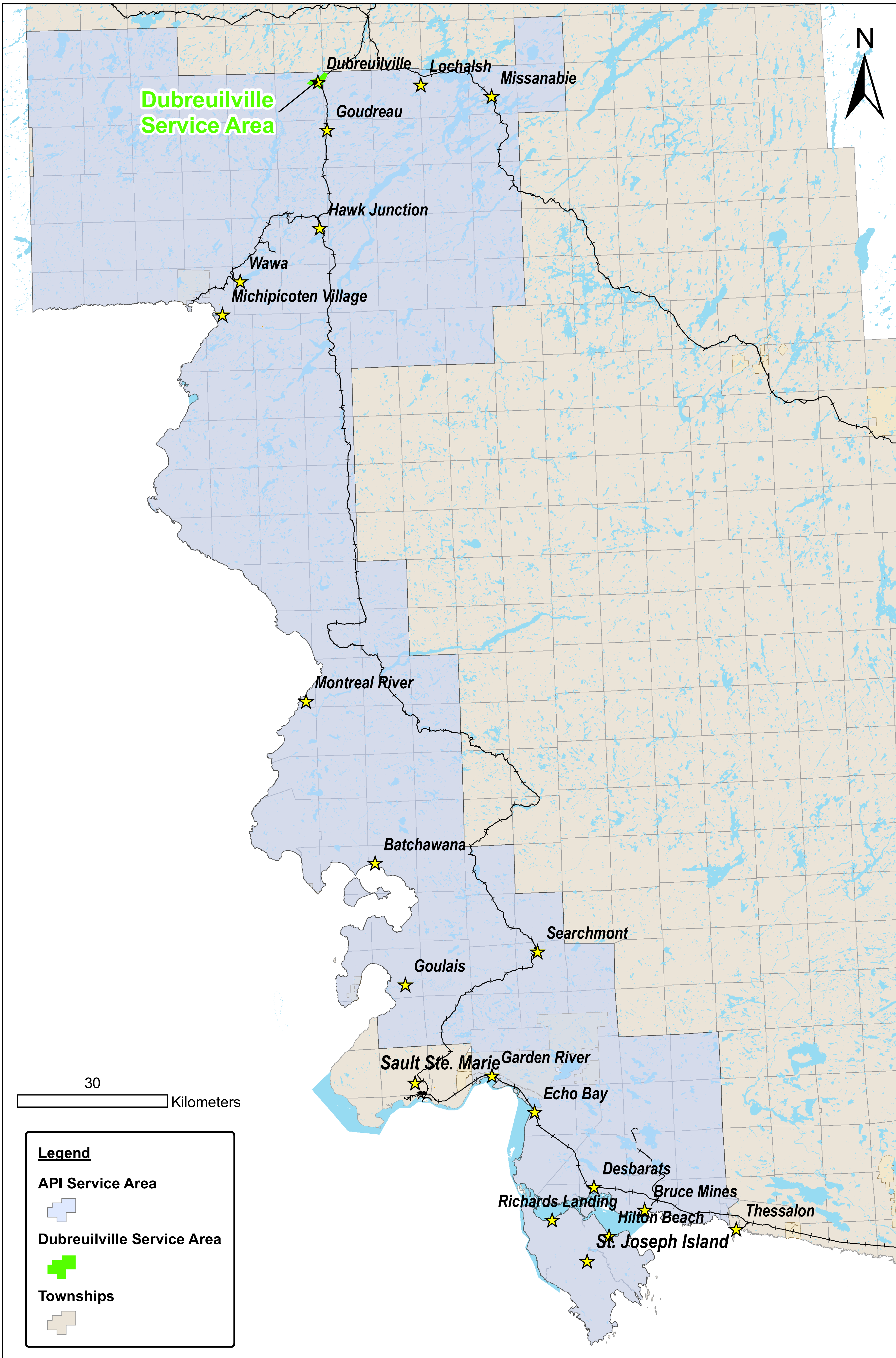
Glen King
Vice President Finance and Chief Financial Officer
Dated at Fort Erie, Ontario, this 17th day of May, 2019

Appendix 1E

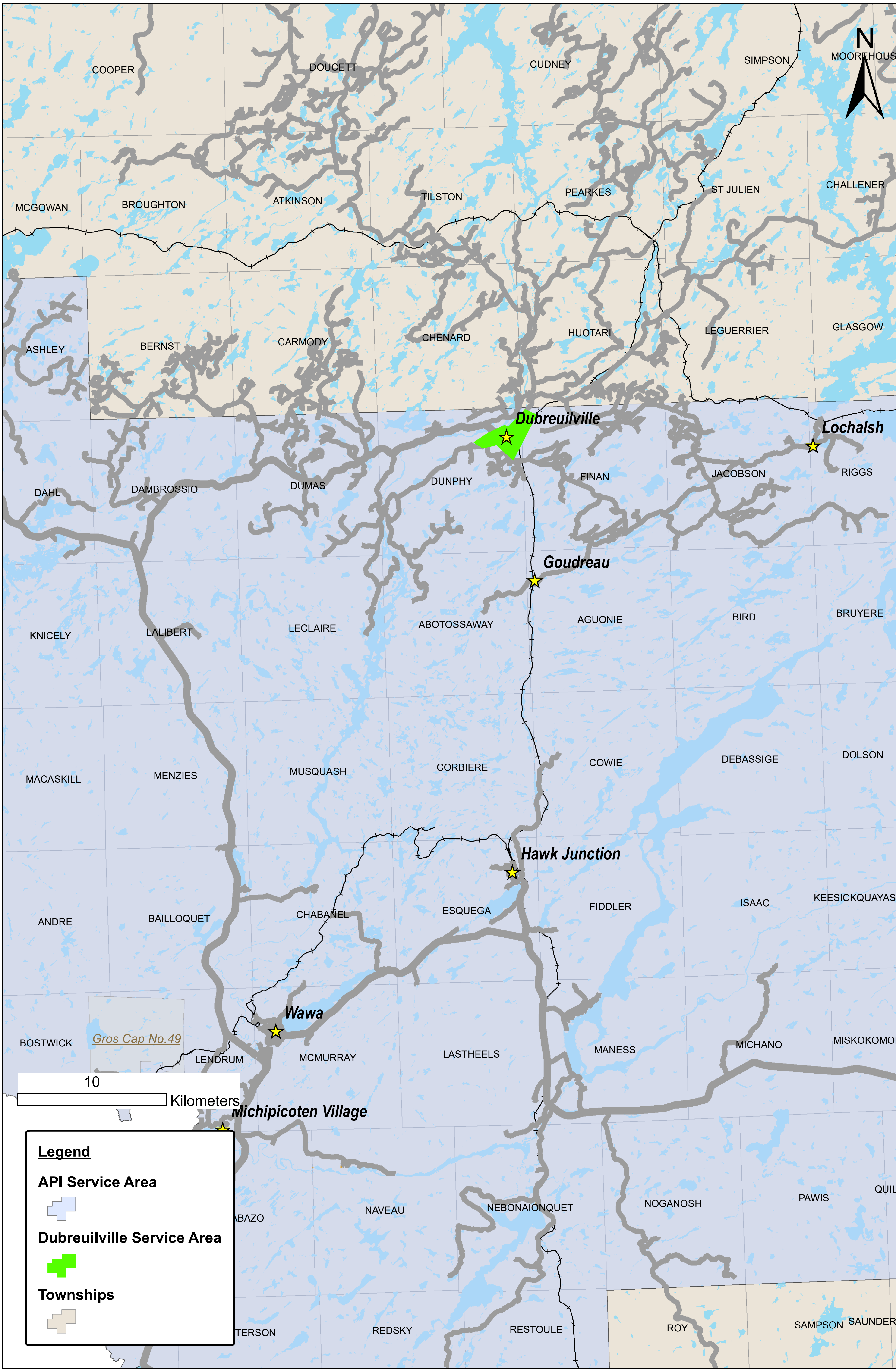
Algoma Power Inc.

2020 Cost of Service

EB-2019-0019



Algoma Power Inc. Service Area With Dubreuilville



Algoma Power Inc. Service Area
With Dubreuilville - Detail View

Appendix 1F

Algoma Power Inc.

2020 Cost of Service

EB-2019-0019

File Number:	EB-2019-0019
Exhibit:	1
Tab:	
Schedule:	
Page:	
Date:	17-May-19

Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Customer Satisfaction Surveys		
- Residential & Small Business Customer Survey 2018 (telephone)	The primary purpose of the Annual Customer Satisfaction survey is to gather information about satisfaction, customer affinity, feelings about outages and bills. Respondents are given an open-ended question to provide suggestions for improvement. For Fall 2018 additional questions around preferred method for LDC to communicate with customers when there is a billing issue or an unplanned outage. Respondents were asked about their satisfaction with their access to services and their priority rating for 12 operational issues.	Questions used in the telephone survey about communication preferences, satisfaction with access to services, and priority ratings were replicated in the Taking A.I.M. online process. Feedback and insights are used to shape the COS 5 year plan.
- Residential & Small Business Customer Survey 2017 & 2016 (telephone)	In addition to the primary purpose of the Annual Customer Satisfaction survey, feedback about the role technology plays in achieving higher levels of service for customers and making the LDC more efficient were asked. Respondents were asked to assign an importance level for 10 customer relevant technologically enabled operational items.	Algoma Power respondents are more cautious about the effect of technology on their lives than other Ontario LDC respondents. Year over year comparison, 2017 vs 2016, of the importance of online access for certain items showed growth. To make getting service easier, Algoma Power responded by putting a series of forms covering 20+ items on their website. Customers can also email customer service directly from the website. Algoma Power also added a "Make Your Voice Count" link to encourage customers to provide their opinions, views and ideas. Taking A.I.M. Chapter 6 and Chapter 7 surveys were enhanced to gather more insight into the technologically enabled operational items.
- Residential & Small Business Customer Survey 2015 (telephone)	In addition to the primary purpose of the Annual Customer Satisfaction survey, Algoma Power took the opportunity to learn more about respondent expectations as they relate to Outages and Outage Management.	Algoma Power survey respondents rate API just as favourably as found in the UtilityPULSE database for other LDCs, as it relates to having a standard of reliability that meets their expectation. However that standard is less stringent. For example 41% of UtilityPULSE database respondents indicated that 1-2 outages per year was acceptable, it was 1 in 3 (32%) for API respondents. Further follow-up on outages and outage management shaped the Taking A.I.M. Chapter 4 survey, included were questions about willingness to pay for improvements in reliability.
- Electricity Safety survey 2015	This is a standardized survey to engage consumers in Algoma Power community about electricity safety.	This was a baseline survey, Algoma results were compared with the results from 34 LDCs.
- Electricity Safety survey 2017	Second run to engage consumers about electricity safety.	Algoma Power's score of 82 was identical to the average score for 33 Ontario LDCs. In order to help educate, Algoma Power put an interactive electricity safety quiz, with supporting explainer videos, on line.
Community Outreach/Stakeholder Sessions		
Your Kilowatt Hour Sessions - provide walk-in locations for customers to have face-to-face interactions with customer service and/or CDM staff. Opportunity to edcuate customers and address any concerns. Four sessions held in primary locations.		
Your Kilowatt Hour Session - Wawa - January 11, 2018	Scheduled meetings to answer cust questions. 2 Customers made appointments but did not show due to weather conditions.	Spoke with customer about her needs over the phone (how OESP amount is determined, CDM measures, Explanation of delivery charges, Usage chart, doesn't like TOU due to being a senior with limited income and home at peak times). The other came to our office at another time wanting to understand his Equal Billing Plan.
Your Kilowatt Hour Session - Garden River-January 31, 2018	Scheduled meetings to answer cust questions. 1 Customer made appointment but did not show.	Spoke with customer about her needs over the phone.
Your Kilowatt Hour Session - Searchmont - October 10, 2018	Scheduled meetings to answer cust questions. 4 Customers made appointments.	1 cancelled as found API's website helpful to understand delivery charges and to understand her bill. Another cancelled as it worked better for her to attended our office to discuss delivery charges as a seasonal customer. Of the 2 who attended 1 wanted to understand bill (overview) and recieve energy efficiency ideas, and the other wanted to understand his bill relating to seasonal rate class.

Your Kilowatt Hour Sessions - St. Joe Island -Nov 27, 2018	Scheduled meetings to answer cust questions. 9 Customers scheduled appointments.	The topics discussed were Bill understanding, rates, delivery charges, options for electirc heat, and efficiency ideas. One microFit customer requested breakdown on how he was billed. This was provided to him three days after the event.
Annual API Contractor Night - April 25, 2018	Engage contractors to meet customer needs	Followup with contractor per individual needs
Annual Roads Superintendents Meeting	Co-ordinate work plans per municipality	Followup with Rd. Sup't per individual needs
Community Stakeholder Meeting - Nov 28, 2018	Invite all municipalities & boards with presentation covering Customer Engagement, Operations, Capital & Maintenance. Provide updates regarding: o API's Capital and Maintenance Programs 2016/17 o Stakeholdering o Capital Workflow – Road Relocations/Expansions o Vegetation Management o Forestry activities and timelines o Connection Plans o Working in Proximity, Electrical Hazards etc.	Minutes sent to all attendees after the event. A few reached out about the "Make Your Voice Count" survey.
Forestry Outreach		
- Forestry Outreach - held seven sessions to provide customers with information on API vegetation mananagement program. This forum also allowed for customers to ask questions and provide feedback.		
- Seedy Saturday SSM - March 10, 2018	Vegetation Mgmt Program display/overview: Had a table at this community event and handed out phamplets and brochures on environmental topics and cdm programs. Provided public with info on VM work program and why and how we manage vegetation	API followed up with customers to discuss vegetation management practices, property related concerns and to discuss right tree, right place providing recommendations of plant species based on site locations. API followed up with approximately 15 customers from this event.
- Sustain Algoma Expo - June 2, 2018	Vegetation Mgmt Program display/overview: Had a table at this community event and handed out phamplets and brochures on environmental topics and cdm programs. Provided public with info on VM work program and why and how we manage vegetation	API followed up with customers to discuss vegetation management practices, property related concerns and to discuss right tree, right place providing recommendations of plant species based on site locations. API followed up with approximately 15 customers from this event.
- Lower Island Lake landowner Meeting - April 5, 2018	The meeting presentations provided an overview of API's obligation and rights as an LDC to provide safe, reliable service, industry standards and best management practices and API's Vegetation Management Plan as it relates to our service territory. The meeting concluded with a question and answer period for consumers and landowners. . Handouts where provided to attendees including API's Frequently Asked Question's, Electrical Safety Authority's (ESA) brochures: ESA Tree Trimming, ESA Tree Trimming Obligations and ESA Tree Planting Guide, and Corridors for Life brochure on Right, Tree, Right Place.	Contacted individual customers who were having concerns with the VM program, 5 additional site visits resulted
- Wawa Notification Meeting Wawa – June 7, 2018	The meeting presentations provided an overview of API's obligation and rights as an LDC to provide safe, reliable service, industry standards and best management practices and API's Vegetation Management Plan as it relates to our service territory. The meeting concluded with a question and answer period for consumers and landowners. . Handouts where provided to attendees including API's Frequently Asked Question's, Electrical Safety Authority's (ESA) brochures: ESA Tree Trimming, ESA Tree Trimming Obligations and ESA Tree Planting Guide, and Corridors for Life brochure on Right, Tree, Right Place.	Contacted individual customers who were having concerns with the VM program, more site visits resulted
- Bruce Mines Community Meeting - June 25, 2018	The meeting presentations provided an overview of API's obligation and rights as an LDC to provide safe, reliable service, industry standards and best management practices and API's Vegetation Management Plan as it relates to our service territory. The meeting concluded with a question and answer period for consumers and landowners. . Handouts where provided to attendees including API's Frequently Asked Question's, Electrical Safety Authority's (ESA) brochures: ESA Tree Trimming, ESA Tree Trimming Obligations and ESA Tree Planting Guide, and Corridors for Life brochure on Right, Tree, Right Place.	Contacted individual customers who were having concerns with the VM program, 4 additional site visits resulted

- Desbarats Community Meeting - June 28, 2018	The meeting presentations provided an overview of API's obligation and rights as an LDC to provide safe, reliable service, industry standards and best management practices and API's Vegetation Management Plan as it relates to our service territory. The meeting concluded with a question and answer period for consumers and landowners. . Handouts where provided to attendees including API's Frequently Asked Question's, Electrical Safety Authority's (ESA) brochures: ESA Tree Trimming, ESA Tree Trimming Obligations and ESA Tree Planting Guide, and Corridors for Life brochure on Right, Tree, Right Place.	Contacted individual customers who were having concerns with the VM program, 4 additional site visits resulted
- Heyden, Goulais River, Batchawana Community Meeting July 16, 2018	The meeting presentations provided an overview of API's obligation and rights as an LDC to provide safe, reliable service, industry standards and best management practices and API's Vegetation Management Plan as it relates to our service territory. The meeting concluded with a question and answer period for consumers and landowners. . Handouts where provided to attendees including API's Frequently Asked Question's, Electrical Safety Authority's (ESA) brochures: ESA Tree Trimming, ESA Tree Trimming Obligations and ESA Tree Planting Guide, and Corridors for Life brochure on Right, Tree, Right Place.	Contacted individual customers who were having concerns with the VM program, 5 additional site visits resulted
CDM Outreach		
- Three sessions held to educate customers on various conservation programs while also allowing for feedback.	Through its CDM programs, API has developed a strong working relationship with a number of customers in the residential, commercial and industrial sectors.	As a result of the knowledge gained about the operations of these customers, API is able to proactively reach out to these customers as new programs become available. These customers also reach out to API to seek advice as they make their own investment decisions.
- Michipicoten High School Presentation - May 3, 2018	Wawa Energy Plan Implementation Initiative - Addresses energy efficeincy concepts and programs	Program information provided directly to attendees at the event, inclusive of application avenues and contact information.
- Wawa BIA Meeting - February 13, 2018	Presentation Re: SOE incentives for businesses, specifically the Retrofit program	Continual communication as program participation interest arises.
- Sustain Algoma Expo - June 2, 2018	Promotion of Save ON Energy suite of programs as well as the AffordAbility Fund program.	Program information provided directly to customers at the event, inclusive of application avenues and contact information.
Other Supporting Engagement Activities		
- Social Media (Outage Communication specific)	Social media consumption has been fairly low (approx 3% of total customers)	API does post outage related information via the social media channels (Twitter and Facebook) to keep following customers informed.
- Social Media (general communications)	Customer look for the latest utility, government information. Access to providing opinions and/or signing up for new programs such as e-billing	The API website is constantly responding to these requests with content updates to ensure the information is kept current with what's going on in the industry and what's important to customers
- Technology Based	Continued requests for self help portal. Information around consumption and bill payment	Myhydro Eye and e-billing information is provided to customers who subscribe to the services.
- Front Desk Support	Face to face interaction with customers has always been requested for bill payments or general inquiries	API will continue to foster this form of communication as it allows the organization to "connect" with customers.
Newsletter - sent out May and November, 2018	These Newsletters advise of Safety concerns, Engagement tools, Contests, What we are doing in our Communities, Regulatory information. November contained "Make Your Voice Count" survey information and invitation to add input. November also covered charges and rate application information in the "Legislation Corner."	There were not any inquiries API is aware of
- Social Services	Low income customers have unique needs to support payment of services.	API recognizes these needs and will make every effort to communicate special programs and/or services to support eligible customers.
Taking AIM - Customer Engagement Program		
- UtilityPULSE facilitated review of Customer Engagement activities	The purpose of this session was to: - Conduct a review of current CE activities - Leverage CE activities for gathering feedback - Identify ways to get the best from internal resources - Ensure understanding of requirements to support COS application	Clarification of roles and responsibilities between internal resources, corporate resources and third party resources as they relate to various customer engagement activities. Project time-table was also established. UtilityPULSE also lead a discussio about current industry & customer trends. Action was taken to leverage API's investment in the annual telephone customer survey to capture additional customer feedback. Topic areas for online surveys were identified.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 1	Chapter survey 1 is designed to gauge the level of respondent disposition, i.e., positive or negative, towards Algoma Power as a company. Respondents would be introduced to important concepts such as: Make Your Voice Count and Wisdom from Customers. This was a Level 1 (Informing & Information Gathering) & 2 (Gathering Feedback) engagement survey which is about raising awareness, providing education, and capturing perceptions. The primary goal of the Taking A.I.M. process is to break down a large complex topics into smaller more manageable pieces.	AP is very highly rated as a trusted and trustworthy company. This finding, along with others in Chapter 1 survey, helped shape the style and format of future chapter surveys. Respondents were given "open" space to provide feedback about the COS application, their wants & needs, and any other topic they would like to raise. Additionally, there was a second "open" space question to request contact from an AP professional.

- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 2	Chapter survey 2 is designed to gauge respondent's knowledge level about the industry. This survey is meant as an industry educational piece for respondents. Respondents were introduced to a concept called Test Your Knowledge. This was a Level 1 Engagement survey which is about raising awareness and providing education.	Knowledge level about the industry is low, the average score was 35 out of 100. However we did learn that there was no need to shy away from putting actual $$$ in costs or investments in questions. However future chapter surveys will have to take into account that the knowledge level is low.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 3	Chapter survey 3 is about gaining a better understanding of customer priorities and testing out various strategy options for dealing with issues which affects costs. This was a Level 2 (Gathering Feedback) and Level 3 (Capturing Insights by Involving Stakeholders) engagement survey. This survey also introduced respondents to a concept called Help Us Decide.	Respondents were asked to assign a priority level to 13 operational items which affect costs. Results are used to determine which items have more support by the customer base. Findings include, from respondent feedback, the majority of respondents support status quo or current standards as it relates to things such as: vegetation management. Survey results also show that current availability of call-centre staff can continue at current levels.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 4	Chapter survey 4 is about billing and outages. This is a Level 2 and Level 3 engagement survey. Bills & blackouts (outages) are known as the "Killer B's" - a very important topic for customers. Barriers to moving to e-bills were ranked by respondents. Questions about current reliability standards, expectations about the acceptable number and length of outages, and willingness to pay for an improvement in the standard of reliability was asked.	Survey results do not support a need to raise current standards are they relate to: accurately billing customers, standard of reliability, or quickly handling outages. API learned that the 2 major barriers for moving customers to e-bills was "some customers do not have access to the internet" and "some customers are not comfortable with technology". API also learned that customers much prefer telephone notification for push type of communications over other means. These findings, coupled with other findings in the Taking A.I.M. process indicates that the adoption for technology based operational improvements will be slower than LDCs in large urban areas.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 5	Chapter survey 5 is about prioritizing capital investments in the electricity network. This is a Level 2 and Level 3 engagement survey. Topics covered include: Consulting other electricity entities when planning capital expenses for the electricity network, Meeting regulatory and legal requirements, Replacing equipment, Planning for the longer term, Keeping facilities, tools, and equipment in good working order.	API's COS application is influenced by findings from consultation and interaction with other parties regarding local and regional planning issues. Findings include: System access investments should be about meeting mandated obligations and helping the community. Going forward System Renewal should be at a level that doesn't increase outages any higher than those experienced over the past 3 years. The COS application should maitain the current level of investment in facilities, tools and equipment.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 6	Chapter survey 6 is about identifying priorities and testing concepts as they relate to subjects such as: communication, customer care operations, satisfaction with information provided on things such as electricity safety, and facilities. This is a Level 3 and Level 4 (Gaining Wisdom by Participating with People) engagement survey.	Findings include a desire for more communication. API put an electricity safety quiz with explainer videos on their website. Respondents were asked about their willingness to pay for 12 Customer Care operational items, Chapter 7 questions on the same 12 items were adjusted in order to gain further insight. Findings also show that respondents would support a pragmatic approach to retro-fitting or replacing facilities.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 7	Chapter survey 7 is about specific DSP topics, capital and other investments in Operations and Customer Care operational changes/enhancements. This survey is a Level 3 and Level 4 engagement survey.	Decision making for API's COS application will be influenced by respondents' ranking of 9 decision-making criteria. The top three: Keep costs low. Maintain safe, reliable distribution of electricity and reduce response times to outages. Data shows there were 8% of respondents unwilling to pay any additional costs for any items such as system renewal, system service, general plant and vegetation management. Regardless of the rationale used to support COS increases, there will be a small but important respondent group who will oppose the increase. However, a clear majority support inflationary type increases.

Appendix 1G

Algoma Power Inc.

2020 Cost of Service

EB-2019-0019

CONNECTING YOU TO **ENERGY INFORMATION YOU CAN USE**

BILLING | **SAFETY**

Electronic Customer Engagement Tools

E-BILLING

Snowbirds and Travelers – Signing up for e-billing is an easy way to receive your bills no matter where you are in the world.

CALL BLASTS

Your Utility often communicates with customers by automated telephone messages to advise of community meetings, contests, initiatives, planned outages, and account status. You may opt out of these messages. If this option is chosen, you will not receive further calls related to the message you are opting out of. If you have opted out of a message in error, please contact your utility.

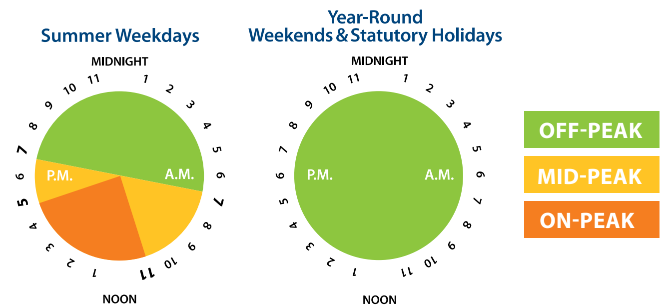
NEVER MISS A PAYMENT DUE DATE

Sign up for Pre-Approved Debit by contacting your local utility.

Spring planting? Remember to ensure you are not planting trees that will grow into power lines. Contact your utility for more information.

Time-of-Use

PROVINCIAL TIME-OF-USE SUMMER RATE PERIOD IN EFFECT MAY 1 - OCTOBER 31, 2019.



Electronic Communication

Your utility will use your email address on file to send electronic information from time-to-time. If you wish to opt out of this option, please contact your local utility.

To report a street light that is non-operational, please call your local Municipal office.

EQUAL PAYMENT PLAN (EPP) – Your Utility will notify you by letter if your EPP payment needs aligning (historical usage and current payments are not equal to annual consumption). Annually, at settlement, the monthly payment is adjusted to reflect past 12 months consumption for the new EPP year.

Your Safety Minute

Stray Voltage is the varying amounts of low-level voltage that exists between the earth and electrically-grounded farm equipment. At high levels, the voltages cause a threat to the health and behaviour of livestock. If you think Farm Stray Voltage is harming your livestock, please call your local utility for an inspection.

Make the area safe, it is the law. Safety standards are a requirement when work is being completed around live power lines. Death or severe injury can occur when contact is made with live wires. It is the constructor's responsibility to ensure everyone on the work site adheres to the safe limits of approach for live lines. FortisOntario's "Third Party in Proximity" program provides the mechanism to notify your local utility of work to be completed in the proximity of our electrical lines. Contact your local utility to complete notification documents prior to commencing work.

REGULATORY **CORNER**

SECURITY DEPOSITS

If you are a low-income customer your utility will waive your security deposit. Please contact your local utility for more information.

LATE PAYMENT CHARGES

Interest charged on overdue amounts is applicable the day after the due date and is calculated at 1.5% monthly. Interest on overdue amounts compounds daily.

PROPOSED CHANGES TO CUSTOMER SERVICE RULES

The Ontario Energy Board (OEB) is proposing a suite of changes to strengthen customer service rules that protect electricity consumers in the province. Please see **www.oeb.ca/newsroom/2018/customer-service-rules-review** for more information.

CALL BEFORE YOU DIG! CONTACT ON1CALL TO REQUEST YOUR FREE LOCATE. ON1CALL.COM • 1-800-400-2255

Canadian Niagara Power Inc. A FORTIS Ontario Company | Eastern Ontario Power A FORTIS Ontario Company | Algoma Power Inc. A FORTIS Ontario Company

SPRING | SUMMER 2019

making connections

CONNECTING YOU TO ENERGY INFORMATION YOU CAN USE

IN YOUR COMMUNITY

SUPPORTING OUR COMMUNITIES

UNITED WAY DONATION
FortisOntario Companies and its employees proudly supported the United Way by donating a total of $51,921.00 in 2018. The United Way programs cover essential services, reducing poverty, workforce entry, and food security to support healthy and vibrant communities.

FORT ERIE SPCA
November 2018 was dedicated to giving back to our four-legged friends at the Fort Erie SPCA. Through various fundraising activities, our Canadian Niagara Power family raised $916.74 in donations. This donation sponsored a kennel for one year as well as a mound of food for the facility!

API POWER OF GIVING FOOD DRIVE
In December 2019 Algoma Power collected several boxes of non-perishable food items collected during API's Power of Giving Food Drive along with a combined monetary donation by employees and company of $477.80.

CONGRATULATIONS TO OUR $500.00 WINNERS:

We thank all of our customers who signed up for e-Billing during our recent contest. Congratulations to our $500.00 winners: Township of St. Joseph, Jeanne & Ed Arthurs, Kaveh Mirsaedi, Donna Korytko, Nikki & Tyler Thibodeau, Kris Anderson, Antoinette Mendes de Franca, Majbah Ahmed, Sean Cooke, and the Regional Municipality of Niagara.

Grand Prize Winner, Lawrence Renaud

MAKING YOUR VOICE COUNT

Algoma Power Inc.'s "Make Your Voice Count" survey contest ended January 31, 2019. A $10.00 credit for each survey completed has been applied to customer accounts. The input from API customers provided insight into customer viewpoints which aids the prioritizing of future initiatives. Congratulations to our Grand Prize Contest Winner, Lawrence Renaud, who received $1500.00 towards a new EnergyStar® refrigerator.

TO REPORT A POWER OUTAGE OR A FALLEN LINE CALL OUR 24 HOUR EMERGENCY SERVICE:

Canadian Niagara Power:
Fort Erie & Port Colborne 1.844.501.9473 (WIRE)
Eastern Ontario Power 1.844.601.9473 (WIRE)
Algoma Power 1.844.901.9473 (WIRE)

LIKE YOUR UTILITY'S FACEBOOK PAGE and stay informed about what is happening in the electric industry, programs, funding, and contests.

THE BEST WAY FOR YOU TO ACCESS INFORMATION when larger unplanned outages occur — follow your local utility: **@APIpower, @CNPpower, @EOPpower**

fortisontario.com cnpower.com | easternontariopower.com | algomapower.com

SPRING CLEANING

LEADS TO **SPRING SAVINGS**

AIR IT OUT

Install a clothesline or drying rack in your back yard and get that fresh spring breeze to dry your laundry. Hardware stores have a great selection that are easy to install. No outdoor space? Try an indoor drying rack.

MAKE YOUR WINDOWS WORK

Insulated drapes come with thermal fabric and are available in many fashionable colours and patterns. Using them can keep your home cool.

LET THE SUN SHINE IN

Clean your windows to help fill up your house with more sunlight and less power. Also, Daylight Savings Time starts in March, so you can keep the lights off well into the evening.

FILTER OUT WINTER

Spring is the ideal time to change or clean your furnace and air conditioner filters, which have been collecting dust all winter. Cleaning the filters will help them run more efficiently.

DON'T DUCK OUT OF CLEANING YOUR DUCTS

If you haven't done it for a few years, getting your ducts cleaned can improve air quality and help your heating, air conditioning and ventilation systems operate efficiently.

TIME TO CHANGE THE AIR CONDITIONER?

Don't wait until the hottest day of the summer. Stay cool with a new air conditioner with a high energy efficiency rating.

KEEP THE REFRIGERATOR COOL

If your fridge is coughing and wheezing, it's probably wasting energy and on its last legs. Getting a new ENERGYSTAR®-rated fridge or freezer may save you up to $125 a year in electricity costs.

FAN OUT

Air conditioners will kick in and out when thermostat settings give them the signal that the temperature is too high or low. Fans are designed to circulate air to maintain room temperature at a consistent level at the hottest times of the day. You'll save energy, money and wear-and tear on your air conditioner by using a fan more often.

Avoid over-filling your fridge, which decreases air circulation and makes it work harder and less efficiently.

Afford Ability Fund™ Ontario

YES! We can help ease what you spend on electricity. For good!

If energy-saving upgrades are out of reach, we're here to help.

Your local electric utility and community services are working together to help you improve your home's energy efficiency with free energy-saving upgrades.

You may qualify for free energy-saving products, including:

- **ENERGY STAR® certified LEDs**
- **ENERGY STAR® certified appliances**
- **Insulation and weatherstripping**

Spend less, save more!

All you need to do is let us know you need to reduce your electricity bill. Whether you rent or own, live in a house or an apartment, you are eligible.

Three ways we may be able to help:

1. Receive a Home Energy Kit with products which may include ENERGY STAR® certified light bulbs, a power bar and/or faucet aerators, along with energy-saving tips.
2. Receive a visit from a Home Energy Advisor. They'll create an Energy Plan for you and can arrange for ENERGY STAR® certified products and appliances.
3. If your home is heated electrically, you'll receive all the benefits listed above, plus you may qualify for home insulation and/or an ENERGY STAR® certified heat pump.

Visit AffordAbilityFund.org Or call: 1-855-494-FUND

Affordability Fund™ is a trade-mark of Affordability Fund Trust. Used under license.

Appendix 1H

Algoma Power Inc.

2020 Cost of Service

EB-2019-0019

Financial statements of
Algoma Power Inc.

December 31, 2017

Deloitte.

Deloitte LLP
25 Corporate Park Drive
3rd Floor
St. Catharines ON L2S 3W2
Canada

Tel: 905-323-6000
Fax: 905-323-6001
www.deloitte.ca

Independent Auditors' Report

To the Shareholder of
Algoma Power Inc.

We have audited the accompanying financial statements of Algoma Power Inc., which comprise the balance sheet as at December 31, 2017, and the statements of earnings and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Algoma Power Inc. as at December 31, 2017 and the results of its operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Other Matters

The financial statements of Algoma Power Inc. for the year ended December 31, 2016, were audited by another auditor who expressed an unmodified opinion on those statements on February 17, 2017

Deloitte LLP

Chartered Professional Accountants
Licensed Public Accountants
March 20, 2018

Algoma Power Inc.
Balance sheet
As at December 31, 2017
(In thousands of dollars)

	Notes	2017	2016
		$	$
Assets			
Current assets			
Cash		**685**	908
Restricted cash	10	**100**	100
Accounts receivable	12	**4,485**	5,356
Income taxes receivable		**—**	85
Materials and supplies		**126**	69
Regulatory assets	14	**654**	239
Prepaid expenses		**216**	259
		6,266	7,016
Utility capital assets, net	2	**90,727**	86,601
Intangible assets, net	3	**16,764**	17,436
Accrued pension benefit asset	4	**2,427**	850
Regulatory assets	14	**7,796**	8,601
Other assets		**33**	38
		124,013	120,542
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	12	**4,559**	3,800
Income taxes payable		**42**	—
Regulatory liabilities	14	**385**	388
Due to related parties	6	**10,419**	2,389
		15,405	6,577
Long-term debt	7, 12	**51,601**	51,584
Future tax liabilities	5	**3,556**	2,592
Accrued other retirement benefit liability	4	**7,425**	7,011
Regulatory liabilities	14	**865**	1,358
Contributions in aid of construction		**782**	671
		79,634	69,793
Commitments and contingencies	11		
Shareholder's equity			
Capital stock	8	**44,008**	44,008
Retained earnings		**371**	6,741
		44,379	50,749
		124,013	120,542

The accompanying notes are an integral part of the financial statements.

Approved by the Board

_______________________________, Director

_______________________________, Director

Algoma Power Inc.

Statement of earnings and retained earnings

Year ended December 31, 2017
(In thousands of dollars)

	Notes	2017	2016
		$	$
Revenue			
Sale of energy		**22,305**	24,749
Distribution		**23,056**	22,745
Other		**195**	499
		45,556	47,993
Expenses			
Cost of power purchased		**22,305**	24,749
Operating		**12,837**	12,530
Amortization	9	**3,438**	3,326
		38,580	40,605
Operating earnings before the following		**6,976**	7,388
Other regulatory adjustments	14	**(93)**	(93)
Interest expense	7	**(2,778)**	(2,732)
Earnings before income taxes		**4,105**	4,563
Provision for income taxes	5	**475**	441
Net earnings for the year		**3,630**	4,122
Retained earnings, beginning of year		**6,741**	2,619
Dividends paid	6	**(10,000)**	—
Retained earnings, end of year		**371**	6,741

The accompanying notes are an integral part of the financial statements.

Algoma Power Inc.
Statement of cash flows
Year ended December 31, 2017
(In thousands of dollars)

	Notes	2017	2016
		$	$
Operating activities			
Net earnings for the year		**3,630**	4,122
Add (deduct) items not involving cash			
Amortization	9	**3,786**	3,646
Amortization of debt issuance costs		**17**	16
Loss (gain) on disposal of utility capital assets		**200**	(60)
Future income taxes		**963**	1,184
Accrued pension benefit asset		**(1,577)**	2
Accrued other retirement benefit liability		**414**	401
Long-term regulatory assets and liabilities		**312**	(799)
		7,745	8,512
Net change in non-cash working capital balances related to operations	10	**9,356**	656
		17,101	9,168
Investing activities			
Proceeds on sale of utility capital assets		**7**	66
Additions to utility capital assets		**(7,406)**	(8,307)
Additions to intangible assets		**(66)**	(272)
Change in other assets		**4**	(30)
		(7,461)	(8,543)
Financing activities			
Increase (decrease) in contributions in aid of construction		**137**	(27)
Dividends paid		**(10,000)**	—
		(9,863)	(27)
Net (decrease) increase in cash during the year		**(223)**	598
Cash, beginning of year		**908**	310
Cash, end of year		**685**	908

The accompanying notes are an integral part of the financial statements.

1. Basis of accounting and summary of significant accounting policies

Incorporation

Algoma Power Inc. ("API" or the "Company") is engaged in the distribution of electricity to the area adjacent to Sault Ste. Marie, Ontario and is subject to the regulations of the Ontario Energy Board ("OEB").

API operated as a division of Great Lakes Power Limited ("GLPL") from January 1, 2009 to June 30, 2009. In order to comply with Section 71 of OEB regulatory requirements, GLPL split out its distribution division by creating a separate legal entity called Great Lakes Power Distribution Inc. ("GLPDI"). This entity began operating as a separate legal entity effective July 1, 2009. On October 8, 2009, there was a change of control as Fortis Ontario Inc. (the "Parent") acquired 100% of the shares of GLPDI and changed the name to Algoma Power Inc.

(a) Basis of accounting

These financial statements have been prepared in accordance with the accounting standards for private enterprises ("ASPE"), as per Part II of the *CPA Handbook* - Accounting, which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada.

(b) Significant accounting policies

Regulation

The distribution rates of API are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs of API.

API is subject to Ontario Regulation 335/07, which is the Rural and Remote Rate Protection subsidy program ("RRRP"). The RRRP is calculated as the deficiency between the approved revenue requirement from the OEB and current customer distribution rates adjusted for the average rate increase across the Province of Ontario. API qualifies for this subsidy because it has less than seven customers per kilometre and a service area that extends beyond 10,000 kilometres. All general service and large customer classes have been reclassified as residential class under Ontario Regulation 445/07.

On August 14, 2015, API filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2016, based on 4GIRM. The OEB calculated the value of the inflation factor for incentive rate setting, for rate changes effective in 2016, to be 2.1%. The OEB assigned a stretch factor of 0.6% based on the updated benchmarking study for use for rates effective in 2016. The resulting net price cap index adjustment for API was 1.5% (i.e. 2.1% - (0% + 0.6%)). The 1.5% adjustment applies to distribution rates [fixed and variable charges] uniformly for the Seasonal and Street Lighting customer classes. The OEB approved the application of the 1.8% RRRP adjustment factor to the distribution rates for the Residential R-1 and Residential R-2 classes. The OEB found that the amount of RRRP of $13,678 for the year commencing January 1, 2016 accurately reflected the OEB's findings pursuant to the applicable regulations and approved a monthly payment of $1,140 effective January 1, 2016.

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Regulation (continued)

Beginning with electricity distribution rates effective in 2016, decoupling of electricity distribution rates for the Residential customer class was being introduced; complete decoupling is expected to take eight consecutive years for residential customers and ten years for seasonal customers to fully implement.

On August 12, 2016, API filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2017, based on 4GIRM. On October 27, 2016, the OEB updated its inflation factor for 2017 Price Cap IR applications, and subsequently provided API with a calculation of the RRRP rate adjustment applicable to API's Residential customer classes. The net price cap index adjustments for API was updated to be 1.3% (i.e. 1.9% - (0% + 0.6%)). This was based on a province-wide inflation factor of 1.9%, less productivity factor of 0% and stretch factor of 0.6%. The assignment of the stretch factors was determined by the OEB as a result of updates to its benchmarking analysis research. The rate increase applicable to Residential classes, based on the OEB's RRRP calculation is 2.96%. The OEB found that the amount of RRRP of $13,499 for the year commencing January 1, 2017 accurately reflects the OEB's findings pursuant to the applicable regulations and approved a monthly payment of $1,125 effective January 1, 2017.

On August 14, 2017, API filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2018, based on 4GIRM. The application includes Residential decoupling calculations in accordance with the Board's Policy for transition to fully fixed rates. For the application, a stretch factor of 0.60% was approved based on the updated benchmarking study for rates effective in 2018. As a result, the net price cap index adjustment for API was 0.6% (i.e. 1.2% - (0% + 0.6%)). The 0.6% adjustment will be applied to distribution rates for the Seasonal and Street Lighting customer classes, following other adjustments to reflect changes in cost allocation between classes resulting from the settlement agreement in API's 2015 Cost of Service application. A Rural and RRRP adjustment factor of 2.52% will be applied to the distribution rates for the Residential R-1 and Residential R-2 classes.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expense in 2017 were $43 ($27 in 2016).

Utility capital assets and capitalization policy

Distribution assets are those used to distribute electricity at lower voltages (generally below 50 kilovolts). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

(In thousands of dollars)

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Utility capital assets and capitalization policy (continued)

The service life range and average remaining service life of the utility capital assets are as follows:

	Service life range (years)	Average remaining service life (years)
Distribution	10 to 50	37.3
Other	5 to 20	6.1

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the utility capital assets using the straight-line method at a composite rate 2.10% (2.08% in 2016)

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the assets involved.

Capitalization policy

The Company's capitalization policy is in accordance with the OEB's requirements to use a "modified IFRS" accounting basis. API, as permitted by the OEB, has recognized the financial differences arising as a result of the 2013 accounting changes to amortization expense and capitalization policies (Note 14).

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the intangible assets using the straight-line method.

The service life range and average remaining service life of the intangible assets are as follows:

	Service life range (years)	Average remaining service life (years)
Software costs	5 to 10	4.8
Land rights and other	40 to 50	29.7

Asset retirement obligations

ASPE requires the recognition of an asset retirement obligation in the period during which a legal obligation associated with the retirement of a tangible long-lived asset is incurred and when a reasonable estimate of this amount can be made.

The Company has determined that there are asset retirement obligations associated with some parts of its distribution systems; however, none of these are material requiring recognition under Section 3110 of the CPA Handbook.

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Revenue recognition

Revenue from the distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year, a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue in the current year.

Unbilled revenue included in accounts receivable as at December 31, 2017 is $2,857 ($3,337 in 2016).

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing on the balance sheet date. Gains and losses on translation are included in the statement of earnings. Revenue and expenses denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing on the transaction date.

Employee benefit plans

Effective January 1, 2014, the Company has adopted new CPA Handbook Section 3462, Employee Future Benefits, for its accounting of pension benefits and other retirement benefits. As allowed under new Section 3462, the Company has made an accounting policy choice to measure its defined benefit plan obligations using the funding valuation approach. This approach uses the most recent completed actuarial valuations prepared for funding purposes as the basis of measuring defined benefit plan obligations. Even though other retirement benefits are not funded, Section 3462 requires that such liabilities can be measured on a basis consistent with funded plans. As well, the Company is using a roll-forward technique in the years between valuations to estimate the defined benefit obligations. Pension plan assets are valued at fair value as of the balance sheet date.

The Company made an application to the OEB to continue to account for pension and other retirement benefits under the former Section 3461. In December 2013, the OEB issued a Decision and Order approving the establishment of specific variance accounts as of January 1, 2013 to recognize the difference in expense between Sections 3461 and 3462 as long-term regulatory assets or liabilities for 2013 and future years, which will be disposed of in future cost of service proceedings, subject to the OEB's prudence review at that time

Income taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured using the enacted and the substantively enacted tax rates expected to apply to taxable income in the period in which temporary differences are expected to be recovered or settled. The Company recognizes regulatory assets and liabilities related to future income tax liabilities and assets for the amount of future income taxes expected to be recovered from customers in future electricity rates.

(In thousands of dollars)

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Use of estimates

The preparation of financial statements in conformity with ASPE requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

2. Utility capital assets

Utility capital assets consist of the following:

			2017
	Cost	**Accumulated amortization**	**Net book value**
	$	**$**	**$**
Distribution	**141,863**	**55,326**	**86,537**
Other	**11,104**	**6,914**	**4,190**
	152,967	**62,240**	**90,727**

			2016
	Cost	Accumulated amortization	Net book value
	$	$	$
Distribution	136,070	53,392	82,678
Other	10,375	6,452	3,923
	146,445	59,844	86,601

The amounts above include assets under construction, which are not subject to amortization, of $2,011 ($1,751 in 2016).

3. Intangible assets

Intangible assets consist of the following:

			2017
	Cost	**Accumulated amortization**	**Net book value**
	$	**$**	**$**
Land rights and right of ways	**20,914**	**5,133**	**15,781**
Software costs	**2,800**	**1,817**	**983**
	23,714	**6,950**	**16,764**

(In thousands of dollars)

3. Intangible assets (continued)

			2016
	Cost	Accumulated amortization	Net book value
	$	$	$
Land rights and right of ways	20,847	4,602	16,245
Software costs	2,801	1,610	1,191
	23,648	6,212	17,436

4. Employee future benefits

The Company maintains a defined benefit pension plan and a defined contribution pension plan providing pension benefits, and defined benefit plans providing other retirement benefits.

Information about API's benefit plans is as follows:

	Pension benefit plans		Other retirement plans	
	2017	2016	**2017**	2016
	$	$	**$**	$
Accrued benefit obligation				
Balance, beginning of year	**26,362**	25,450	**7,011**	6,610
Current service costs	**577**	533	**258**	248
Finance costs	**1,252**	1,209	**333**	314
Employee contributions	**190**	234	**—**	—
Benefits paid	**(1,136)**	(1,029)	**(173)**	(164)
Actuarial (gains) losses	**(11)**	(35)	**(4)**	3
Balance, end of year	**27,234**	26,362	**7,425**	7,011
Plan assets				
Fair value, beginning of year	**27,212**	26,302	**—**	—
Interest income	**1,289**	1,245	**—**	—
Return on plan assets	**1,563**	(36)	**—**	—
Contributions	**733**	730	**173**	164
Benefits paid	**(1,136)**	(1,029)	**(173)**	(164)
Fair value, end of year	**29,661**	27,212	**—**	—
Funded status - plan surplus (deficit)	**2,427**	850	**(7,425)**	(7,011)

The measurement date for the plan assets and the accrued benefit obligation was as at December 31, 2017. The effective date of the most recent actuarial valuation was as at December 31, 2014 and the date of the next required valuation for funding purposes is as at December 31, 2017, and will be completed by September 2018.

(In thousands of dollars)

4. Employee future benefits (continued)

The plan assets held at the measurement date are represented by the following categories:

	%
Canadian equity funds	**10**
Foreign equity funds	**41**
Canadian fixed income funds	**49**

As at December 31, 2017, one of the defined benefit pension plans had a net accrued benefit liability of $321 ($350 in 2016). This plan had no plan assets in 2017 or 2016.

	Pension benefit plans		Other retirement plans	
	2017	2016	**2017**	2016
	$	$	**$**	$
Significant assumptions used				
Discount rate, beginning of year	**4.75%**	4.75%	**4.75%**	4.75%
Discount rate, end of year	**4.75%**	4.75%	**4.75%**	4.75%
Rate of compensation increase	**3.50%**	3.50%	**—**	—
Initial health care trend rate	**—**	—	**5.71%**	5.76%
Average remaining service of active employees (years)	**16**	16	**16**	16
Net benefit expense for the year				
Current service costs	**577**	533	**258**	248
Finance costs	**(37)**	(36)	**333**	314
Remeasurement costs	**(1,574)**	1	**(4)**	3
Regulatory adjustments	**1,459**	(254)	**74**	53
Net benefit expense	**425**	244	**661**	618

The total expense for the Company's defined contribution pension plan for the year amounted to $113 ($122 in 2016).

5. Income taxes

The provision for income taxes consists of the following:

	2017	2016
	$	$
Current income taxes	**355**	312
Future income taxes	**963**	1,184
Future income taxes transferred to regulatory assets	**(843)**	(1,055)
	475	441

During the year, the Company recorded $843 in regulatory assets and a corresponding decrease to future income tax expense, for the amount of future income taxes expected to be collected from customers in future electricity rates.

(In thousands of dollars)

5. Income taxes (continued)

Future tax assets (liabilities) are comprised of the following:

	2017	2016
	$	$
Future tax assets (liabilities)		
Utility capital assets	**(4,789)**	(4,066)
Employee future benefits	**1,095**	997
Rate mitigation accrual	**1,598**	1,718
Regulatory assets	**(1,355)**	(1,131)
Other assets	**(105)**	(110)
Net future tax liabilities	**(3,556)**	(2,592)

6. Related party transactions

During the year, the Company entered into transactions with related parties summarized as follows:

	2017	2016
	$	$
Dividends paid to FortisOntario Inc.	**10,000**	—
Interest paid to FortisOntario Inc.	**44**	13
Management fees paid to FortisOntario Inc.	**493**	469
Reimbursement for expenses paid on behalf of and services provided to FortisOntario Inc.	**(287)**	—
Administrative service fees from Canadian Niagara Power Inc.	**2,164**	2,055
Reimbursement for expenses paid on behalf of and services provided by Canadian Niagara Power Inc.	**886**	718
Reimbursement for expenses paid on behalf of and services provided by FortisOntario Inc.	**636**	554
Reimbursement for expenses paid on behalf of and services provided by Cornwall Street Railway, Light and Power Company Limited.	**207**	221

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

As at December 31, the amounts due from related parties are summarized as follows:

	2017	2016
	$	$
FortisOntario Inc.	**10,419**	2,389

(In thousands of dollars)

6. Related party transactions (continued)

Details of relationships with related parties are as follows:

- FortisOntario Inc. owns a 100% interest in the capital stock of the Company
- Cornwall Street Railway, Light and Power Company Limited is a wholly owned subsidiary of FortisOntario Inc.
- Canadian Niagara Power Inc. is a wholly owned subsidiary of FortisOntario Inc.

7. Long-term debt

Long-term debt consists of the following:

	2017	2016
	$	$
5.118% senior unsecured notes due on December 16, 2041	**52,000**	52,000
Unamortized debt issue costs	**(399)**	(416)
	51,601	51,584

The senior unsecured notes bear interest at 5.118% and are repayable at maturity on December 16, 2041. The senior unsecured notes were issued on December 16, 2011 and interest is payable semi-annually. Interest expense for the year amounted to $2,661 ($2,661 in 2016).

8. Capital stock

The authorized and issued shares consist of 90,831,810 common shares without par value.

9. Amortization

Amortization consists of the following:

	2017	2016
	$	$
Amortization of utility capital assets	**3,074**	2,905
Amortization of intangible assets	**738**	764
Amortization of contributions in aid of construction	**(26)**	(23)
	3,786	3,646
Vehicle amortization allocated	**(348)**	(320)
	3,438	3,326

(In thousands of dollars)

10. Statement of cash flows

The net change in non-cash working capital balances related to operations consists of the following:

	2017	2016
	$	$
Accounts receivable	**871**	994
Income taxes receivable	**127**	97
Materials and supplies	**(57)**	(13)
Regulatory assets/ liabilities	**(418)**	(126)
Prepaid expenses	**43**	(7)
Due to/from related parties	**8,031**	1,474
Accounts payable and accrued liabilities	**759**	(1,763)
	9,356	656

Supplemental cash flow information:

	2017	2016
	$	$
Interest paid	**2,717**	2,715
Income taxes paid	**312**	396

The restricted cash is a deposit held by the Ministry of Environment for a Certificate of Approval.

11. Commitments and contingencies

API has a building lease agreement with Hydro One Sault Ste Marie LLP until December 31, 2019 with annual rent, operating costs and municipal taxes of $600.

12. Financial risk management

The Company is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk - Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk - Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk - Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

Credit risk

For cash and accounts receivable due from customers, API's credit risk is limited to the carrying value on the balance sheet.

API is exposed to credit risk from its distribution customers but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third-party collection agencies for overdue accounts. API has a large and diversified distribution customer base which minimizes the concentration of credit risk.

(In thousands of dollars)

12. Financial risk management (continued)

The aging of the Company's trade and other receivables due from customers is as follows:

	$
Not past due	**4,182**
Past due 0–30 days	**56**
Past due 31–60 days	**46**
Past due 61 days and over	**240**
	4,524
Less allowance for doubtful accounts	**39**
	4,485

Liquidity risk

Liquidity risk to API is minimized since the financing of regulated capital and other expenditures is done through internally generated funds. These funds are a result of allowable rate regulated returns and recoveries under the OEB rate regulations mechanism.

API is a subsidiary of the Parent, which is a wholly owned 100% by Fortis Inc., a large investor owned utility, which has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go-forward basis is subject to numerous factors, including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate any liquidity risk, the Company is a party to a committed revolving credit facility and letters of credit facilities totaling $40,000, of which $18,700 is unused. This credit agreement is shared among the subsidiaries of the Parent and is renewed on an annual basis.

The facility is guaranteed by the Parent company and bear interest at the bankers' acceptance rate plus 1.20% in the case of bankers' acceptances and at the bank's prime lending rate plus 0.20% in the case of bank loans.

The following is an analysis of the contractual maturities of the Company's financial liabilities as at December 31, 2017:

	< 1 year	**1–3 years**	**4–5 years**	**> 5 years**	**Total**
	$	**$**	**$**	**$**	**$**
Accounts payable and accrued liabilities	**4,172**	**—**	**—**	**—**	**4,172**
Government remittances payable	**131**	**—**	**—**	**—**	**131**
Customer deposits	**78**	**31**	**143**	**4**	**256**
Long-term debt	**—**	**—**	**—**	**52,000**	**52,000**
	4,381	**31**	**143**	**52,004**	**56,559**

Interest rate risk

Long-term debt is at fixed interest rates thereby minimizing cash flow and interest rate fluctuation exposure. The Company is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. Short-term borrowings for 2017 and 2016 are nil.

(In thousands of dollars)

13. Capital management

API manages its capital to approximate the deemed capital structure reflected in the utility's customer rates or anticipated future rates. API's distribution rates effective on January 1, 2015 are based on a deemed capital structure of 60% debt and 40% equity. API's capital structure consists of third-party debt and common equity, but excludes unamortized debt issue costs.

The managed capital is as follows:

	2017 actual		2016 actual	
	$	**%**	$	%
Debt	**52,000**	**54**	52,000	51
Equity	**44,379**	**46**	50,749	49
	96,379	**100**	102,749	100

14. Regulatory assets and liabilities

Regulatory liabilities net of regulatory assets arise as a result of regulatory requirements.

The Company pays the cost of power on behalf of its customers and recovers these costs through retail billings to its customers. The cost of power includes charges for transmission, wholesale market operations and the power itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represents the costs that have not been recovered from, or settled through, customers as of the balance sheet date. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments as discussed in note 1. In the absence of rate regulation, these costs would be expensed in the period they are incurred.

The OEB has the general power to include or exclude costs, revenues, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in the Company's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Company continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future rates as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

As of December 31, 2015, as discussed in note 1 under "Utility capital assets and capitalization policy", API had a regulatory liability in OEB account 1576 of $1,128. These were transitional adjustments related to accounting changes to amortization and capitalization policy. As a result of the 2015 OEB Decision and Order, API recorded an additional regulatory liability of $93 in 2017, relating to the regulatory return calculated on the approved cumulative regulatory liability of $1,379. A reduction of the regulatory liability of $376 occurred during 2017 due to a repayment to API's customers in the form of a rate rider, which is set to expire in December 2019. The cumulative regulatory liability balance as at December 31, 2017 was $560, of which $385 has been reported as current.

(In thousands of dollars)

14. Regulatory assets and liabilities (continued)

API recorded the following regulatory assets and liabilities as at December 31:

	2017	2016	Remaining rebate period
	$	$	
Current regulatory assets			
Amounts approved in current rates	**654**	239	1 year
Long-term regulatory assets			
Amounts approved in current rates	**738**	1,626	2 years
Retail settlement and other variance accounts	**1,081**	308	2 years
Future taxes to be recovered from customers	**5,113**	4,269	Life of assets
Pension and other retirement benefits	**864**	2,398	EARSL
	7,796	8,601	
Current regulatory liabilities			
Transitional accounting adjustments	**385**	388	1 year
	385	388	
Long-term regulatory liabilities			
Retail settlement and other variance accounts	**690**	903	2 years
Transitional accounting adjustments	**175**	455	2 years
	865	1,358	

Appendix 1I

Algoma Power Inc.

2020 Cost of Service

EB-2019-0019

Financial statements of
Algoma Power Inc.

December 31, 2018

Deloitte.

Deloitte LLP
25 Corporate Park Drive
3rd Floor
St. Catharines ON L2S 3W2
Canada

Tel: 905-323-6000
Fax: 905-323-6001
www.deloitte.ca

Independent Auditors' Report

To the Shareholder of
Algoma Power Inc.

Opinion

We have audited the financial statements of Algoma Power Inc. (the "Company"), which comprise the balance sheet as at December 31, 2018, and the statements of earnings and retained earnings and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2018, and the results of its operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises ("ASPE").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with ASPE, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

Deloitte LLP.

Chartered Professional Accountants
Licensed Public Accountants
February 20, 2019

Algoma Power Inc.

Balance sheet

As at December 31, 2018

(In thousands of dollars)

	Notes	2018	2017
		$	$
Assets			
Current assets			
Cash		**614**	685
Restricted cash	10	**100**	100
Accounts receivable	12	**4,610**	4,518
Materials and supplies		**134**	126
Regulatory assets	14	**185**	654
Prepaid expenses		**192**	216
		5,835	6,299
Utility capital assets, net	2	**96,535**	90,727
Intangible assets, net	3	**16,435**	16,764
Accrued pension benefit asset	4	**3,457**	2,427
Regulatory assets	14	**7,224**	7,796
		129,486	124,013
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	12	**4,698**	4,303
Customer deposits	12	**75**	78
Income taxes payable		**93**	42
Regulatory liabilities	14	**246**	385
Due to related parties	6	**411**	10,419
		5,523	15,227
Long-term customer deposits	12	**240**	178
Promissory note due to parent company	6, 12 and 13	**12,750**	—
Long-term debt	7, 12 and 13	**51,617**	51,601
Future tax liabilities	5	**4,495**	3,556
Accrued other retirement benefit liability	4	**4,773**	7,425
Regulatory liabilities	14	**3,553**	865
Contributions in aid of construction		**835**	782
		83,786	79,634
Commitments and contingencies	11		
Shareholder's equity			
Capital stock	8	**44,008**	44,008
Retained earnings		**1,692**	371
		45,700	44,379
		129,486	124,013

The accompanying notes are an integral part of the financial statements.

Approved by the Board

______________________________, Director

______________________________, Director

Algoma Power Inc.

Statement of earnings and retained earnings

Year ended December 31, 2018
(In thousands of dollars)

	Notes	2018	2017
		$	$
Revenue			
Sale of energy		**21,907**	22,305
Distribution		**23,441**	23,056
Other		**466**	195
		45,814	45,556
Expenses			
Cost of power purchased		**21,907**	22,305
Operating		**12,857**	12,837
Amortization	9	**3,600**	3,438
		38,364	38,580
Operating earnings before the following		**7,450**	6,976
Other regulatory adjustments	14	**(93)**	(93)
Interest expense	6, 7 and 12	**(2,976)**	(2,778)
Earnings before income taxes		**4,381**	4,105
Provision for income taxes	5	**560**	475
Net earnings for the year		**3,821**	3,630
Retained earnings, beginning of year		**371**	6,741
Dividends paid	6	**(2,500)**	(10,000)
Retained earnings, end of year		**1,692**	371

The accompanying notes are an integral part of the financial statements.

(In thousands of dollars)

	Notes	2018	2017
		$	$
Operating activities			
Net earnings for the year		**3,821**	3,630
Add (deduct) items not involving cash			
Amortization	9	**3,987**	3,786
Amortization of debt issuance costs		**16**	17
Loss on disposal of utility capital assets		**22**	200
Future income taxes		**940**	963
Accrued pension benefit asset		**(1,030)**	(1,577)
Accrued other retirement benefit liability		**(2,652)**	414
Long-term customer deposits		**62**	53
Long-term regulatory assets and liabilities		**3,260**	312
		8,426	7,798
Net change in non-cash working capital balances related to operations	10	**(9,311)**	9,307
		(885)	17,105
Investing activities			
Proceeds on sale of utility capital assets		**5**	7
Additions to utility capital assets		**(9,102)**	(7,406)
Additions to intangible assets		**(408)**	(66)
		(9,505)	(7,465)
Financing activities			
Increase in contributions in aid of construction		**69**	137
Promissory note due to parent company		**12,750**	—
Dividends paid		**(2,500)**	(10,000)
		10,319	(9,863)
Net decrease in cash during the year		**(71)**	(223)
Cash, beginning of year		**685**	908
Cash, end of year		**614**	685

The accompanying notes are an integral part of the financial statements.

1. Basis of accounting and summary of significant accounting policies

Incorporation

Algoma Power Inc. ("API" or the "Company") is engaged in the distribution of electricity to the area adjacent to Sault Ste. Marie, Ontario and is subject to the regulations of the Ontario Energy Board ("OEB").

API operated as a division of Great Lakes Power Limited ("GLPL") from January 1, 2009 to June 30, 2009. In order to comply with Section 71 of OEB regulatory requirements, GLPL split out its distribution division by creating a separate legal entity called Great Lakes Power Distribution Inc. ("GLPDI"). This entity began operating as a separate legal entity effective July 1, 2009. On October 8, 2009, there was a change of control as Fortis Ontario Inc. (the "Parent") acquired 100% of the shares of GLPDI and changed the name to Algoma Power Inc.

(a) Basis of accounting

These financial statements have been prepared in accordance with the accounting standards for private enterprises ("ASPE"), as per Part II of the *CPA Handbook* - Accounting, which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada.

(b) Significant accounting policies

Regulation

The distribution rates of API are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs of API.

API is subject to Ontario Regulation 335/07, which is the Rural and Remote Rate Protection subsidy program ("RRRP"). The RRRP is calculated as the deficiency between the approved revenue requirement from the OEB and current customer distribution rates adjusted for the average rate increase across the Province of Ontario. API qualifies for this subsidy because it has less than seven customers per kilometre and a service area that extends beyond 10,000 kilometres. All general service and large customer classes have been reclassified as residential class under Ontario Regulation 445/07.

Beginning with electricity distribution rates effective in 2016, decoupling of electricity distribution rates for the Residential customer class was being introduced; complete decoupling is expected to take eight consecutive years for residential customers and ten years for seasonal customers to fully implement.

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Regulation (continued)

On August 12, 2016, API filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2017, based on 4GIRM. On October 27, 2016, the OEB updated its inflation factor for 2017 Price Cap IR applications, and subsequently provided API with a calculation of the RRRP rate adjustment applicable to API's Residential customer classes. The net price cap index adjustments for API was updated to be 1.3% (i.e. 1.9% - (0% + 0.6%)). This was based on a province-wide inflation factor of 1.9%, less productivity factor of 0% and stretch factor of 0.6%. The assignment of the stretch factors was determined by the OEB as a result of updates to its benchmarking analysis research. The rate increase applicable to Residential classes, based on the OEB's RRRP calculation is 2.96%. The OEB found that the amount of RRRP of $13,499 for the year commencing January 1, 2017 accurately reflects the OEB's findings pursuant to the applicable regulations and approved a monthly payment of $1,125 effective January 1, 2017.

On August 14, 2017, API filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2018, based on 4GIRM. The application includes Residential decoupling calculations in accordance with the Board's Policy for transition to fully fixed rates. For the application, a stretch factor of 0.60% was approved based on the updated benchmarking study for rates effective in 2018. As a result, the net price cap index adjustment for API was 0.6% (i.e. 1.2% - (0% + 0.6%)). The 0.6% adjustment will be applied to distribution rates for the Seasonal and Street Lighting customer classes, following other adjustments to reflect changes in cost allocation between classes resulting from the settlement agreement in API's 2015 Cost of Service application. A Rural and RRRP adjustment factor of 2.52% will be applied to the distribution rates for the Residential R-1 and Residential R-2 classes.

On August 13, 2018, API filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2019, based on 4GIRM. The application included Residential decoupling calculations in accordance with the Board's Policy for transition to fully fixed rates. For the application, a stretch factor of 0.60% was applied as a placeholder based on the updated benchmarking study. As a result, the net price cap index adjustment for API was 0.6% (i.e. 1.2% - (0% + 0.6%)). This was based on a province-wide inflation factor of 1.2%, less productivity factor of 0% and stretch factor of 0.6%. The 0.6% adjustment was applied to distribution rates for the Seasonal and Street Lighting customer classes, following other adjustments to reflect changes in cost allocation between classes resulting from the settlement agreement in API's 2015 CoS application. A RRRP adjustment factor of 2.52% was applied as a placeholder to the distribution rates for the Residential R-1 and Residential R-2 classes. On November 23, 2018, the OEB calculated the inflation factor to be used for 2019 incentive rate setting applications to be 1.5%, up from the 2018 inflation factor of 1.2%. As a result, the net price cap index adjustment for API was 0.9% (i.e. 1.5% - (0% + 0.6%)). A Rural and RRRP adjustment factor of 2.22% will be applied to the distribution rates for the Residential R-1 and Residential R-2 classes.

(In thousands of dollars)

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expense in 2018 were $39 (2017 - $43).

Utility capital assets and capitalization policy

Distribution assets are those used to distribute electricity at lower voltages (generally below 50 kilovolts). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

The service life range and average remaining service life of the utility capital assets are as follows:

	Service life range (years)	Average remaining service life (years)
Distribution	10 to 50	37.0
Other	5 to 20	5.8

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the utility capital assets using the straight-line method at a composite rate 2.14% (2017 - 2.10%).

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the assets involved.

Capitalization policy

The Company's capitalization policy is in accordance with the OEB's requirements to use a "modified IFRS" accounting basis. API, as permitted by the OEB, has recognized the financial differences arising as a result of the 2013 accounting changes to amortization expense and capitalization policies (Note 14).

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the intangible assets using the straight-line method.

The service life range and average remaining service life of the intangible assets are as follows:

	Service life range (years)	Average remaining service life (years)
Software costs	5 to 10	5.1
Land rights and other	40 to 50	28.9

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Asset retirement obligations

ASPE requires the recognition of an asset retirement obligation in the period during which a legal obligation associated with the retirement of a tangible long-lived asset is incurred and when a reasonable estimate of this amount can be made.

The Company has determined that there are asset retirement obligations associated with some parts of its distribution systems; however, none of these are material requiring recognition under Section 3110 of the CPA Handbook.

Revenue recognition

Revenue from the distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year, a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue in the current year.

Unbilled revenue included in accounts receivable as at December 31, 2018 is $2,745 (2017 - $2,857).

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing on the balance sheet date. Gains and losses on translation are included in the statement of earnings. Revenue and expenses denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing on the transaction date.

Employee benefit plans

Effective January 1, 2014, the Company has adopted new CPA Handbook Section 3462, Employee Future Benefits, for its accounting of pension benefits and other retirement benefits. As allowed under new Section 3462, the Company has made an accounting policy choice to measure its defined benefit plan obligations using the funding valuation approach. This approach uses the most recent completed actuarial valuations prepared for funding purposes as the basis of measuring defined benefit plan obligations. Even though other retirement benefits are not funded, Section 3462 requires that such liabilities can be measured on a basis consistent with funded plans. As well, the Company is using a roll-forward technique in the years between valuations to estimate the defined benefit obligations. Pension plan assets are valued at fair value as of the balance sheet date.

The Company made an application to the OEB to continue to account for pension and other retirement benefits under the former Section 3461. In December 2013, the OEB issued a Decision and Order approving the establishment of specific variance accounts as of January 1, 2013 to recognize the difference in expense between Sections 3461 and 3462 as long-term regulatory assets or liabilities for 2013 and future years, which will be disposed of in future cost of service proceedings, subject to the OEB's prudence review at that time

(In thousands of dollars)

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Income taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured using the enacted and the substantively enacted tax rates expected to apply to taxable income in the period in which temporary differences are expected to be recovered or settled. The Company recognizes regulatory assets and liabilities related to future income tax liabilities and assets for the amount of future income taxes expected to be recovered from customers in future electricity rates.

Use of estimates

The preparation of financial statements in conformity with ASPE requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

2. Utility capital assets

Utility capital assets consist of the following:

			2018
	Cost	**Accumulated amortization**	**Net book value**
	$	**$**	**$**
Distribution	**149,568**	**57,769**	**91,799**
Other	**12,127**	**7,391**	**4,736**
	161,695	**65,160**	**96,535**

			2017
	Cost	Accumulated amortization	Net book value
	$	$	$
Distribution	142,479	55,326	87,153
Other	10,488	6,914	3,574
	152,967	62,240	90,727

The amounts above include assets under construction, which are not subject to amortization, of $4,830 (2017 - $2,627).

(In thousands of dollars)

3. Intangible assets

Intangible assets consist of the following:

			2018
	Cost	**Accumulated amortization**	**Net book value**
	$	**$**	**$**
Land rights and right of ways	**21,081**	**5,667**	**15,414**
Software costs	**3,040**	**2,019**	**1,021**
	24,121	**7,686**	**16,435**

			2017
	Cost	Accumulated amortization	Net book value
	$	$	$
Land rights and right of ways	20,914	5,133	15,781
Software costs	2,800	1,817	983
	23,714	6,950	16,764

4. Employee future benefits

The Company maintains a defined benefit pension plan and a defined contribution pension plan providing pension benefits, and defined benefit plans providing other retirement benefits.

Information about API's benefit plans is as follows:

(In thousands of dollars)

4. Employee future benefits (continued)

	Pension benefit plans		Other retirement plans	
	2018	2017	**2018**	2017
	$	$	**$**	$
Accrued benefit obligation				
Balance, beginning of year	**27,234**	26,362	**7,425**	7,011
Current service costs	**580**	577	**270**	258
Finance costs	**1,294**	1,252	**353**	333
Employee contributions	**214**	190	**—**	—
Benefits paid	**(1,294)**	(1,136)	**(190)**	(173)
Actuarial (gains) losses	**(2,711)**	(11)	**(3,085)**	(4)
Balance, end of year	**25,317**	27,234	**4,773**	7,425
Plan assets				
Fair value, beginning of year	**29,661**	27,212	**—**	—
Interest income	**1,406**	1,289	**—**	—
Return on plan assets	**(1,691)**	1,563	**—**	—
Contributions	**692**	733	**190**	173
Benefits paid	**(1,294)**	(1,136)	**(190)**	(173)
Fair value, end of year	**28,774**	29,661	**—**	—
Funded status - plan surplus (deficit)	**3,457**	2,427	**(4,773)**	(7,425)

The measurement date for the plan assets and the accrued benefit obligation was as at December 31, 2018. The effective date of the most recent actuarial valuation was as at December 31, 2017 and the date of the next required valuation for funding purposes is as at December 31, 2020, and will be completed by September 2021.

The plan assets held at the measurement date are represented by the following categories:

	%
Canadian equity funds	**9**
Foreign equity funds	**39**
Canadian fixed income funds	**51**
Cash and short trem investments	**1**

As at December 31, 2018, one of the defined benefit pension plans had a net accrued benefit liability of $284 (2017 - $321). This plan had no plan assets in 2018 or 2017.

(In thousands of dollars)

4. Employee future benefits (continued)

	Pension benefit plans		Other retirement plans	
	2018	2017	**2018**	2017
	$	$	**$**	$
Significant assumptions used				
Discount rate, beginning of year	**4.75%**	4.75%	**4.75%**	4.75%
Discount rate, end of year	**5.40%**	4.75%	**5.40%**	4.75%
Rate of compensation increase	**3.50%**	3.50%	**—**	—
Initial health care trend rate	**—**	—	**5.44%**	5.71%
Average remaining service of active employees (years)	**19**	16	**18**	16
Net benefit expense for the year				
Current service costs	**580**	577	**270**	258
Finance costs	**(113)**	(37)	**353**	333
Remeasurement costs	**(1,020)**	(1,574)	**(3,085)**	(4)
Regulatory adjustments	**963**	1,459	**3,221**	74
Net benefit expense	**410**	425	**759**	661

The total expense for the Company's defined contribution pension plan for the year amounted to $135 ($113 in 2017).

5. Income taxes

The provision for income taxes consists of the following:

	2018	2017
	$	$
Current income taxes	**448**	355
Future income taxes	**940**	963
Future income taxes transferred to regulatory assets	**(828)**	(843)
	560	475

During the year, the Company recorded $828 (2017 - $843) in regulatory assets and a corresponding decrease to future income tax expense, for the amount of future income taxes expected to be collected from customers in future electricity rates.

(In thousands of dollars)

5. Income taxes (continued)

Future tax assets (liabilities) are comprised of the following:

	2018	2017
	$	$
Future tax assets (liabilities)		
Utility capital assets	**(5,535)**	(4,789)
Employee future benefits	**1,229**	1,095
Rate mitigation accrual	**1,486**	1,598
Regulatory assets	**(1,574)**	(1,355)
Other assets	**(101)**	(105)
Net future tax liabilities	**(4,495)**	(3,556)

6. Related party transactions

During the year, the Company entered into transactions with related parties summarized as follows:

	2018	2017
	$	$
Dividends paid to FortisOntario Inc.	**2,500**	10,000
Interest paid to FortisOntario Inc.	**211**	44
Management fees paid to FortisOntario Inc.	**479**	493
Reimbursement for expenses paid on behalf of and services provided to FortisOntario Inc.	**(145)**	(287)
Administrative service fees from Canadian Niagara Power Inc.	**1,952**	2,164
Reimbursement for expenses paid on behalf of and services provided by Canadian Niagara Power Inc.	**1,132**	886
Reimbursement for expenses paid on behalf of and services provided by FortisOntario Inc.	**689**	636
Reimbursement for expenses paid on behalf of and services provided by Cornwall Street Railway, Light and Power Company Limited.	**218**	207

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

As at December 31, the amounts due to related parties are summarized as follows:

	2018	2017
	$	$
FortisOntario Inc.	**411**	10,419
Promissory note due to parent company	**12,750**	-

(In thousands of dollars)

6. Related party transactions (continued)

A promissory note of $12,750 due to the parent company bears interest at 4.13% and is payable on demand. There are no specific terms of repayment for this note.

Details of relationships with related parties are as follows:

- FortisOntario Inc. owns a 100% interest in the capital stock of the Company
- Cornwall Street Railway, Light and Power Company Limited is a wholly owned subsidiary of FortisOntario Inc.
- Canadian Niagara Power Inc. is a wholly owned subsidiary of FortisOntario Inc.

7. Long-term debt

Long-term debt consists of the following:

	2018	2017
	$	$
5.118% senior unsecured notes due on December 16, 2041	**52,000**	52,000
Unamortized debt issue costs	**(383)**	(399)
	51,617	51,601

The senior unsecured notes bear interest at 5.118% and are repayable at maturity on December 16, 2041. The senior unsecured notes were issued on December 16, 2011 and interest is payable semi-annually. Interest expense for the year amounted to $2,661 (2017 - $2,661).

8. Capital stock

The authorized and issued shares consist of 90,831,810 common shares without par value.

9. Amortization

Amortization consists of the following:

	2018	2017
	$	$
Amortization of utility capital assets	**3,268**	3,074
Amortization of intangible assets	**736**	738
Amortization of contributions in aid of construction	**(17)**	(26)
	3,987	3,786
Vehicle amortization allocated	**(387)**	(348)
	3,600	3,438

Vehicle amortization is allocated to utility capital assets and operating expenses on a vehicle time per-use basis.

(In thousands of dollars)

10. Statement of cash flows

The net change in non-cash working capital balances related to operations consists of the following:

	2018	2017
	$	$
Accounts receivable	**(92)**	875
Income taxes payable	**51**	127
Materials and supplies	**(8)**	(57)
Regulatory assets/liabilities	**330**	(418)
Prepaid expenses	**24**	43
Due to/from related parties	**(10,008)**	8,031
Customer deposits	**(3)**	7
Accounts payable and accrued liabilities	**395**	699
	(9,311)	9,307

Supplemental cash flow information:

	2018	2017
	$	$
Interest paid	**2,959**	2,717
Income taxes paid	**355**	312

The restricted cash is a deposit held by the Ministry of Environment for a Certificate of Approval.

11. Commitments and contingencies

API has a building lease agreement with Hydro One Sault Ste Marie LLP until December 31, 2019 with annual rent, operating costs and municipal taxes of $600.

12. Financial risk management

The Company is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk - Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk - Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk - Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

Credit risk

For cash and accounts receivable due from customers, API's credit risk is limited to the carrying value on the balance sheet.

API is exposed to credit risk from its distribution customers but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third-party collection agencies for overdue accounts. API has a large and diversified distribution customer base which minimizes the concentration of credit risk.

(In thousands of dollars)

12. Financial risk management (continued)

The aging of the Company's trade and other receivables due from customers is as follows:

	2018	2017
	$	$
Not past due	**4,224**	4,215
Past due 0–30 days	**169**	56
Past due 31–60 days	**49**	46
Past due 61 days and over	**211**	240
	4,653	4,557
Less allowance for doubtful accounts	**43**	39
	4,610	4,518

Liquidity risk

Liquidity risk to API is minimized since the financing of regulated capital and other expenditures is done through internally generated funds. These funds are a result of allowable rate regulated returns and recoveries under the OEB rate regulations mechanism.

API is a subsidiary of the Parent, which is a wholly owned 100% by Fortis Inc., a large investor owned utility, which has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go-forward basis is subject to numerous factors, including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate any liquidity risk, the Company is a party to a committed revolving credit facility and letters of credit facilities totaling $40,000, of which $25,700 (2017 - $18,700) is unused. This credit agreement is shared among the subsidiaries of the Parent and is renewed on an annual basis.

The facility is guaranteed by the Parent company and bear interest at the bankers' acceptance rate plus 1.20% in the case of bankers' acceptances and at the bank's prime lending rate plus 0.20% in the case of bank loans.

The following is an analysis of the contractual maturities of the Company's financial liabilities as at December 31, 2018:

	< 1 year	**1 - 3 years**	**4 - 5 years**	**> 5 years**	**Total**
	$	**$**	**$**	**$**	**$**
Accounts payable and accrued liabilites	**4,569**	**—**	**—**	**—**	**4,569**
Government remittances payable	**129**	**—**	**—**	**—**	**129**
Customer deposits	**75**	**69**	**171**	**—**	**315**
Long-term debt	**—**	**—**	**—**	**52,000**	**52,000**
	4,773	**69**	**171**	**52,000**	**57,013**

(In thousands of dollars)

12. Financial risk management (continued)

The following is an analysis of the contractual maturities of the Company's financial liabilities as at December 31, 2017:

	< 1 year	1 - 3 years	4 - 5 years	> 5 years	Total
	$	$	$	$	$
Accounts payable and accrued liabilites	4,172	—	—	—	4,172
Government remittances payable	131	—	—	—	131
Customer deposits	78	31	143	4	256
Long-term debt	—	—	—	52,000	52,000
	4,381	31	143	52,004	56,559

Interest rate risk

Long-term debt is at fixed interest rates thereby minimizing cash flow and interest rate fluctuation exposure. The Company is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. Short-term borrowings for 2018 and 2017 are nil.

13. Capital management

API manages its capital to approximate the deemed capital structure reflected in the utility's customer rates or anticipated future rates. API's distribution rates effective on January 1, 2015 are based on a deemed capital structure of 60% debt and 40% equity. API's capital structure consists of third-party debt, affiliate debt and common equity, but excludes unamortized debt issue costs.

The managed capital is as follows:

	2018 actual		2017 actual	
	$	**%**	$	%
Debt	**64,750**	**59**	52,000	54
Equity	**45,700**	**41**	44,379	46
	110,450	**100**	96,379	100

14. Regulatory assets and liabilities

Regulatory liabilities net of regulatory assets arise as a result of regulatory requirements.

The Company pays the cost of power on behalf of its customers and recovers these costs through retail billings to its customers. The cost of power includes charges for transmission, wholesale market operations and the power itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represents the costs that have not been recovered from, or settled through, customers as of the balance sheet date. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments as discussed in note 1. In the absence of rate regulation, these costs would be expensed in the period they are incurred.

The OEB has the general power to include or exclude costs, revenues, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in the Company's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Company continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future rates as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

As of December 31, 2015, as discussed in note 1 under "Utility capital assets and capitalization policy", API had a regulatory liability in OEB account 1576 of $1,128. These were transitional adjustments related to accounting changes to amortization and capitalization policy. As a result of the 2015 OEB Decision and Order, API recorded an additional regulatory liability of $93 in 2018 (2017 - $93), relating to the regulatory return calculated on the approved cumulative regulatory liability of $1,379. A reduction of the regulatory liability of $408 occurred during 2018 (2017 - $376) due to a repayment to API's customers in the form of a rate rider, which is set to expire in December 2019. The cumulative regulatory liability balance as at December 31, 2018 was $246 (2017 - $560), all of which has been reported as current (2017 - $385).

(In thousands of dollars)

14. Regulatory assets and liabilities (continued)

API recorded the following regulatory assets and liabilities as at December 31:

	2018	2017	Remaining rebate period
	$	$	
Current regulatory assets			
Amounts approved in current rates	**185**	654	1 year
Long-term regulatory assets			
Amounts approved in current rates	**616**	738	2 years
Retail settlement and other variance accounts	**668**	1,081	2 years
Future taxes to be recovered from customers	**5,940**	5,113	Life of assets
Pension and other retirement benefits	**—**	864	EARSL
	7,224	7,796	
Current regulatory liabilities			
Transitional accounting adjustments	**246**	385	1 year
	246	385	
Long-term regulatory liabilities			
Retail settlement and other variance accounts	**233**	690	2 years
Pension and other retirement benefits	**3,320**	—	EARSL
Transitional accounting adjustments	**—**	175	2 years
	3,553	865	

15. Comparative figures

Certain figures for 2017 have been reclassified to conform to the presentation adopted in 2018.

Appendix 1J

Algoma Power Inc.

2020 Cost of Service

EB-2019-0019

ALGOMA POWER INC. ($000's)					
BALANCE SHEET VARIANCES	**2016 AUDITED FINANCIAL STATEMENTS("AFS")**	**2016 2.1.7 RRR**	**VARIANCE**	**2.1.7 RRR OEB Accts Mapped**	**EXPLANATION**
Capital Assets	146,445	146,445	-	**1805 to 1875, 1905 to 1990, 2055**	
Net Intangibles	17,436	17,436	-	**1606 to 1612, 2120**	
Contributions and Grants	(671)	(671)	-	**1995**	
Accumulated Amortization of Assets	(59,844)	(59,844)	-	**2105**	
Net Balance Sheet Variance			-		
INCOME STATEMENT VARIANCES					
Sales of Electricity		24,749		**4006 to 4076**	
Distribution Services Revenue		22,750		**4080 to 4090**	
Other Operating Revenue		445		**4205 to 4245**	
Other Revenue		(630)		**4305 to 4415**	
Revenue	47,993	47,314	679		Other income/deductions and investment income grouped with operating expenses in AFS, and regulatory debits grouped with regulatory adjustments on AFS
Power Supply Expenses (Working Capital)		24,749		**4705 to 4751**	
Operation and Maintenance (Working Capital)		6,361		**5005 to 5195**	
Billing and Collection (Working Capital)		908		**5305 to 5425**	
Administrative and General Expenses (Working Capital)		4,502		**5605 to 5695**	
Operating Expenses	37,279	36,520	759		Other income/deductions,investment income, donations and property taxes grouped with expenses in AFS
Amortization of Assets	3,326	3,326	-	**5705 to 5740**	
Regulatory Adjustments	(93)		(93)		Accounting policy changes
Donations		61	(61)	**6205**	Donations grouped with operating expenses in AFS
Interest Expense	2,732	2,732	-	**6005 to 6045**	
Income Tax Expense	441	553	(112)	**6105 to 6115**	Property taxes grouped with operating expenses in AFS
Profit (Loss)	4,122	4,122	-		
Net Income Statement Variance			-		

ALGOMA POWER INC. ($000's)					
BALANCE SHEET VARIANCES	**2017 AUDITED FINANCIAL STATEMENTS("AFS")**	**2017 2.1.7 RRR**	**VARIANCE**	**2.1.7 RRR OEB Accts Mapped**	**EXPLANATION**
Capital Assets	152,967	152,967	(0)	**1805 to 1875, 1905 to 1990, 2055**	
Net Intangibles	16,764	16,764	0	**1606 to 1612, 2120**	
Contributions and Grants	(782)	(782)	-	**1995**	
Accumulated Amortization of Assets	(62,240)	(62,240)	0	**2105**	
Net Balance Sheet Variance			0		
INCOME STATEMENT VARIANCES					
Sales of Electricity		22,305		**4006 to 4076**	
Distribution Services Revenue		23,062		**4080 to 4090**	
Other Operating Revenue		375		**4205 to 4245**	
Other Revenue		(849)		**4305 to 4415**	
Revenue	45,556	44,892	664		Other income/deductions and investment income grouped with operating expenses in AFS, and regulatory debits grouped with regulatory adjustments on AFS
Power Supply Expenses (Working Capital)		22,305		**4705 to 4751**	
Operation and Maintenance (Working Capital)		6,715		**5005 to 5195**	
Billing and Collection (Working Capital)		922		**5305 to 5425**	
Administrative and General Expenses (Working Capital)		4,466		**5605 to 5695**	
Operating Expenses	35,142	34,408	734		Other income/deductions,investment income, donations and property taxes grouped with expenses in AFS
Amortization of Assets	3,438	3,438	(0)	**5705 to 5740**	
Regulatory Adjustments	(93)	-	(93)		Accounting policy changes
Donations	-	48	(48)	**6205**	Donations grouped with operating expenses in AFS
Interest Expense	2,778	2,778	0	**6005 to 6045**	
Income Tax Expense	475	589	(114)	**6105 to 6115**	Property taxes grouped with operating expenses in AFS
Profit (Loss)	3,630	3,630	0		
Net Income Statement Variance			0		

ALGOMA POWER INC.
($000's)

BALANCE SHEET VARIANCES	2018 AUDITED FINANCIAL STATEMENTS("AFS")	2018 2.1.7 RRR	VARIANCE	2.1.7 RRR OEB Accts Mapped	EXPLANATION
Capital Assets	161,695	185,817	(24,122)	**1805 to 1875, 1905 to 1990, 2055**	
Intangibles	24,121	-	24,121	**1606 to 1612**	
Net Contributions	(835)	(835)	-	**1995**	
Accumulated Amortization of Assets	(72,846)	(72,847)	1	**2105, 2120**	
Net Capital Assets	112,135	112,136	(0)		
INCOME STATEMENT VARIANCES					
Sales of Electricity		21,907		**4006 to 4076**	
Distribution Services Revenue		23,445		**4080 to 4090**	
Other Operating Revenue		423		**4205 to 4245**	
Other Revenue		(627)		**4305 to 4415**	
Revenue	45,814	45,148	666		Other income/deductions and investment income grouped with operating expenses in AFS, and regulatory debits grouped with regulatory adjustments on AFS
Power Supply Expenses (Working Capital)		21,907		**4705 to 4751**	
Operation and Maintenance (Working Capital)		6,712		**5005 to 5195**	
Billing and Collection (Working Capital)		1,062		**5305 to 5425**	
Administrative and General Expenses (Working Capital)		4,333		**5605 to 5695**	
Operating Expenses	34,764	34,013	751		Other income/deductions, investment income, donations and property taxes grouped with expenses in AFS
Amortization of Assets	3,600	3,600	(0)	**5705 to 5740**	
Regulatory Adjustments	(93)	-	(93)		Accounting policy changes
Donations	-	62	(62)	**6205**	Donations grouped with operating expenses in AFS
Interest Expense	2,976	2,976	0	**6005 to 6045**	
Income Tax Expense	560	676	(116)	**6105 to 6115**	Property taxes grouped with operating expenses in AFS
Profit (Loss)	3,821	3,821	(0)		
Net Income Statement Variance			(0)		

Appendix 1K

Algoma Power Inc.

2020 Cost of Service

EB-2019-0019

Electricity Distribution Licence

ED-2009-0072

Algoma Power Inc.

Valid Until

May 4, 2029

Original signed by

Brian Hewson
Vice President, Consumer Protection and Industry Performance
Ontario Energy Board

Date of Issuance: May 5, 2009
Effective Date: July 1, 2009
Date of Last Amendment: February 8, 2018

Ontario Energy Board	Commission de l’énergie de l’Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th. Floor	27e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

LIST OF AMENDMENTS

Board File No.	Date of Amendment
EB-2009-0403	January 11, 2010
EB-2010-0215	November 12, 2010
EB-2010-0307	March 29, 2011
EB-2011-0402	April 25, 2012
EB-2012-0339	November 8, 2012
EB-2013-0056	June 20, 2013
EB-2014-0324	December 18, 2014
EB-2015-0199	October 8, 2015
EB-2016-0015	January 28, 2016
EB-2017-0101	March 31, 2017
EB-2017-0318	February 8, 2018

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1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**Conservation and Demand Management**" and "**CDM**" means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

"**Conservation and Demand Management Code for Electricity Distributors**" means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

"**distribution services**" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**IESO**" means the Independent Electricity System Operator;

"**Licensee**" means Algoma Power Inc.;

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Net Annual Peak Demand Energy Savings Target**" means the reduction in a distributor's peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

"**Net Cumulative Energy Savings Target**" means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014.

"**OPA**" means the Ontario Power Authority;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Provincial Brand**" means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on May 5, 2009 and expire on May 4, 2029. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender=s transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

21 Conservation and Demand Management

21.1 2011-2014 Conservation and Demand Management Framework

21.1.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 1.280 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 7.370 GWh (collectively the “CDM Targets”), over a four-year period beginning January 1, 2011.

21.1.2 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee’s service area (“Board-Approved CDM Programs”);

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee’s service area under contract with the OPA (“OPA-Contracted Province-Wide CDM Programs”); or

c) a combination of a) and b).

21.1.3 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee’s service area.

21.1.4 The Licensee shall comply with the rules mandated by the Board’s Conservation and Demand Management Code for Electricity Distributors.

21.1.5 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee’s own brand or marks.

21.2 2015-2020 Conservation and Demand Management Framework

21.2.1 The Licensee shall, between January 1, 2015 and December 31, 2020, make CDM programs, available to customers in its licensed service area and shall, as far as is appropriate and reasonable having regard to the composition of its customer base, do so in relation to each customer segment in its service area ("CDM Requirement").

21.2.2 The CDM programs referred to in item 21.2.1 above shall be designed to achieve reductions in electricity consumption.

21.2.3 The Licensee shall meet its CDM Requirement by:

a) making Province-Wide Distributor CDM Programs, funded by the Ontario Power Authority (the "OPA"), available to customers in its licensed service area;

b) making Local Distributor CDM Programs, funded by the OPA, available to customers in its licensed service area; or

c) a combination of a) and b).

21.2.4 The Licensee shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to other licensed electricity distributors upon request.

21.2.5 The Licensee shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to any other person upon request.

21.2.6 The Licensee shall report to the OPA the results of the CDM programs in accordance with the requirements of the licensee's "CDM-related" contract with the OPA.

22 Pole Attachments

22.1 The Licensee shall provide access to its distribution poles to all Canadian carriers, as defined by the Telecommunications Act, and to all cable companies that operate in the Province of Ontario. For each attachment, with the exception of wireless attachments, the Licensee shall charge the rate approved by the Board and included in the Licensee's tariff.

22.2 The Licensee shall:

a) annually report the net revenue, and the calculations used to determine that net revenue, earned from allowing wireless attachments to its poles. Net revenues will be accumulated in a deferral account approved by the Board;

b) credit that net revenue against its revenue requirement subject to Board approval in rate proceedings; and

c) provide access for wireless attachments to its poles on commercial terms normally found in a competitive market.

23 Winter Disconnection, Reconnection and Load Control Devices

23.1 Subject to paragraph 23.4, the Licensee shall not, during a Disconnection Ban Period:

a) disconnect an occupied residential property solely on the grounds of non-payment;

b) issue a disconnection notice in respect of an occupied residential property solely on the grounds of non-payment; or

c) install a load control device in respect of an occupied residential property solely on the grounds of non-payment.

Nothing in this paragraph shall preclude the Licensee from (i) disconnecting an occupied residential property during a Disconnection Ban Period in accordance with all applicable regulatory requirements, including the required disconnection notice, or (ii) installing a load control device in respect of an occupied residential property during a Disconnection Ban Period, in each case if at the unsolicited request of the customer given in writing for that Disconnection Ban Period.

23.2 Subject to paragraph 23.4,

(a) for the 2017/2018 Disconnection Ban Period, if the Licensee had disconnected a residential property on or before November 2, 2017 solely on the grounds of non-payment, the Licensee shall reconnect that property, if an occupied residential property, as soon as possible, and shall do the same in respect of any such property that may be disconnected by Licensee between that date and the commencement of the Disconnection Ban Period. The Licensee shall waive any reconnection charge that might otherwise apply in respect of that reconnection; and

(b) for each subsequent Disconnection Ban Period, the Licensee shall ensure that any residential property that had been disconnected solely on the grounds of non-payment is, if an occupied residential property, reconnected as at the commencement of the Disconnection Ban Period. The Licensee shall waive any reconnection charge that might otherwise apply in respect of that reconnection.

Nothing in this paragraph shall require the Licensee to reconnect an occupied residential property in respect of a Disconnection Ban Period if the customer gives unsolicited notice to the Licensee not to do so in writing for that Disconnection Ban Period and has not rescinded that notice.

23.3 Subject to paragraph 23.4,

(a) for the 2017/2018 Disconnection Ban Period, if the Licensee had installed a load control device in respect of an occupied residential property on or before November 2, 2017 either for non-payment or at the customer's request, the Licensee shall remove that device and restore full service to the property as soon as possible, and shall do the same in respect of any load control device installed in respect of any such property between that date and the commencement of the Disconnection Ban Period. The Licensee shall waive any charge that might otherwise apply in respect of such removal; and

(b) for each subsequent Disconnection Ban Period, the Licensee shall ensure that any load control device installed in respect of an occupied residential property either for non-payment or at the customer's request is removed and full service is restored to the property as at the commencement of the Disconnection Ban Period. The Licensee shall waive any charge that might otherwise apply in respect of such removal.

Nothing in this paragraph shall (i) require the Licensee to remove a load control device in respect of a Disconnection Ban Period if the customer gives unsolicited notice to the Licensee not to do so in writing for that Disconnection Ban Period and has not rescinded that notice; or (ii) prevent the Licensee from installing or maintaining a load control device if the customer makes an unsolicited request in writing for the Licensee to do so for that Disconnection Ban Period and has not rescinded that request.

23.4 Nothing in paragraphs 23.1 to 23.3 shall:

a) prevent the Licensee from taking such action in respect of an occupied residential property as may be required to comply with any applicable and generally acceptable safety requirements or standards; or

b) require the Licensee to act in a manner contrary to any applicable and generally accepted safety requirements or standards.

23.5 The Licensee shall waive any collection of account charge that could otherwise be charged in relation to an occupied residential property during a Disconnection Ban Period.

23.6 For the purposes of paragraphs 23.1 to 23.5:

"Disconnection Ban Period" means the period commencing at 12:00 am on November 15th in one year and ending at 11:59 pm on April 30th in the following year;

“load control device” has the meaning given to it in the Distribution System Code; and

“occupied residential property” means an account with the Licensee:

a) that falls within the residential rate classification as specified in the Licensee’s Rate Order; and
b) that is:

  i. inhabited; or
  ii. in an uninhabited condition as a result of the property having been disconnected by the Licensee or of a load control device having been installed in respect of the property outside of a Disconnection Ban Period.

23.7 Paragraphs 23.1 to 23.5 apply despite any provision of the Distribution System Code to the contrary.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. The Licensee is licensed in respect to the geographic area comprised of the following list of townships:

Memaskwosh	Wishart	Miskokomon
Alanen	Herrick	Dulhut
Charbonneau	Tilley	Nebon
Dahl	Marne	Laronde
Dumas	Havilland	Redsky
Finan	Shields	Allouez
Riggs	Kars	Stone
Rennie	Vankoughnet	Alaire
Keating	Hodgins	Barager
Knicely		Bray
Leclaire	Aweres	Broome
Aguonie	Anderson	Goodwillie
Bruyere		Grootenboer
Legarde Add'l	Garden River Reserve IR14	Labonte
Levesque	Chesley Add'l	Peever
Menzies	Aberdeen	Raaflaub
Corbiere		Smilsky
Debassige	Tarbutt & Tarbutt Add'l	Tronsen
Echum	Plummer Add'l	Nicolet
Warpula	Rose	Olsen
Michipicoten	St. Joseph	Palmer
Fiddler	Jocelyn	Brule
Keesickquayash	Ashley	Fisher
Groseilliers	Chapais	Archibald
Bostwick	Dambrossio	Ley
Lastheels		Tupper
Michano	Jacobson	Gaudette
Nadjiwon	West	Fenwick
Rabazo	Stover	Deroche
Nebonaionquet	Killins	Whitman

Peterson	Lalibert	Pennefather
Restoule	Abotossaway	Jarvis
Tiernan	Bird	Chesley
Stoney	Copenace	Noganosh
Asselin	Legarde	Pawlis
Barnes	Macaskill	Quill
Brimacombe	Musquash	Giles
Bullock	Cowie	Rix
Greenwood	Dolson	Duncan
Labelle	St. Germain	Kehoe
Larson	Andre	MacDonald, Meredith & Aberdeen Add'l
Home	Esquega	Galbraith
Slater	Isaac	Laird
Tolmonen	Laforme	Johnson
Kincaid	Franchere	
Norberg	Michipicoten	Hilton
Ryan	Maness	Morin

2. Concessions 3, 4 and 5 of the Township of Dennis;

3. Approximately forty (40) square kilometres at the western limit of the former Township of Thessalon;

4. 5 rural customers in Kirkwood Township supplied off two short line taps into the Township;

5. Plus the following locations within the City of Sault Ste. Marie:

   (a) 45 Third Line West as at March 14, 2003, excluding those areas of land within 45 Third Line West that are serviced by PUC Distribution Inc. (PUC) as identified in PUC's distribution licence, those being:

   - the areas of land on which the facilities on the northeast corner of 45 Third Line West are located, namely the “gatehouse” and “office”;

   (b) 77 Third Line West as at July 9, 2004;

   (c) 3 Sackville Road;

   (d) 150 Conmee Avenue;

   (e) 429 Hudson Street, excluding those areas within 429 Hudson Street that are serviced by PUC as identified in PUC's distribution licence, those being:

(i) the area of land on which the facility near the northwest corner of Hudson Street and Wellington Street West is located, namely the "yard office";

(ii) the area of land on which the facility near the junction of Hudson Street and St. George Avenue West is located, namely the "skimmer shack"; and

(iii) the area of land on which the railroad crossing signals are located, near the junction of Hudson Street and St. Andrew Terrace; and

(f) 2 Sackville Road.

6. The service area excludes the following locations west of Thessalon on the north side of Hwy.17 which are supplied by Hydro One Networks Inc.:

(a) 12564 Highway 17 West

(b) 12600 Highway 17 West

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

1. The Licensee is exempt from the provisions of the Standard Supply Service Code for Electricity Distributors requiring time-of-use pricing for Regulated Price Plan consumers with eligible time-of-use meters, as of the mandatory date. This exemption applies only for service for the identified 350 hard to reach customers, who as of June 11, 2015 and as per Decision and Order EB-2015-0199 are outside the reach of the Licensee’s smart meter telecommunications infrastructure. This exemption expires December 31, 2019.

2. The Licensee is exempt from the requirements of the following sections of the Affiliate Relationships Code for Electricity Distributors and Transmitters under the conditions specified in section 2 of this Schedule:

   Section 2.2.2

   Where a utility shares information services with an affiliate, all confidential information must be protected from access by the affiliate. Access to a utility’s information services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. A utility shall, if required to do so by the Board, conduct a review of the adequacy, implementation or operating effectiveness of the access protocols and associated contractual provisions which complies with the provision of section 5970 of the CICA Handbook. A utility shall also conduct such a review when the utility considers that there may have been a breach of the access protocols or associated contractual provisions and that such review is required to identify any corrective action that may be required to address the matter. The utility shall comply with such directions as may be given by the Board in relations to the terms of section 5970 review. The results of any such review shall be made available to the Board.

   Section 2.2.3

   A utility shall not share with an affiliate that is an energy service provider employees that are directly involved in collecting, or have access to, confidential information.

3. The Exemptions from the requirements of the Affiliate Relationship Code for Electricity Distributors and Transmitters referred to section 2 of this Schedule (the “Exemptions”) are subject to the following conditions:

   a) The exemptions only apply in respect of the relationship between the Licensee and the following affiliates and not with respect to any other affiliates of the Licensee:

      - FortisOntario Inc.;
      - Fortis Properties Corporation; and
      - Cornwall Street Railway Light and Power Company Limited.
      - Canadian Niagara Power Inc.

b) The Licensee shall not share facilities, confidential information or employees with any affiliate identified in paragraph a) for any purpose other than the provision of services to, or the receipt of services from, the affiliate under the Services Agreements dated September 15, 2010 (the “Services Agreements”) as filed with the Board as part of the materials filed in support of the application for the Exemptions, as such Services Agreements may be amended from time to time.

c) The activities of the Licensee relative to the affiliates identified in paragraph a) shall be governed by, and the Licensee shall be bound by and comply with, the Services Agreements, as amended from time to time.

d) The Licensee shall notify the Board of any material change relative to the materials filed in support of the application for the Exemptions as soon as possible upon becoming aware of such change and in no event later than fifteen days following the date on which the change occurs. Without limiting the generality of the foregoing, this obligation includes notifying the Board in the event of a change in the market activities of either FortisOntario Inc. or Fortis Properties Corporation.

e) The Board may, on its own initiative or upon receipt of notice from the Licensee under paragraph d), by order revoke one or more of the Exemptions, vary one or more of the conditions set out above or impose additional conditions upon becoming aware of any material change relative to the materials filed in support of the application for Exemptions, or for such other reason as the Board considers appropriate.

4. The Licensee is exempt from the provisions of Section 2.10.1 and Sections 7.11.1 to 7.11.7 of the Distribution System Code limiting the use of estimated billing and requiring billing accuracy. This exemption applies only for service to approximately 191 of the identified hard to reach customers who as of June 11, 2015 and as per Decision and Order EB-2015-0199 would fail to meet the Distribution System Code requirements for accurate bills. The identified customers include customers outside the smart meter telecommunications infrastructure reach of Algoma Power Inc. and new hard to reach customers who are expected to be connected to Algoma Power Inc.’s service area during the requested exemption period. This exemption shall be effective as of April 15, 2015 until December 31, 2019.

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

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"ONTARIO POWER GENERATION INC. rebate"

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Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

Appendix 1L

Algoma Power Inc.

2020 Cost of Service

EB-2019-0019

Interim Electricity Distribution Licence

ED-2017-0153

Algoma Power Inc.

Under sections 59 (1) and (2) of the *Ontario Energy Board Act, 1998* for possession and control of the electricity distribution business serving the Town of Dubreuilville

Valid Until

October 2, 2019

Original Signed By

____

Brian Hewson
Vice President, Consumer Protection & Industry Performance
Ontario Energy Board
Date of Issuance: April 4, 2017
Date of Amendment: October 3, 2017
Date of Amendment: April 3, 2018
Date of Amendment: October 3, 2018
Date of Amendment: April 2, 2019

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto, ON M4P 1E4

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

Interim Electricity Distribution Licence

1. Definitions

In this Licence:

“**Accounting Procedures Handbook**” means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

“**Act”** means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

“**Affiliate Relationships Code for Electricity Distributors and Transmitters**” means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

“**distribution services**” means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

“**Distribution System Code**” means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

“**Electricity Act”** means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

“good utility practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

“**Licensee**” means Algoma Power Inc.;

“**Market Rules**” means the rules made under section 32 of the Electricity Act;

“**Performance Standards**” means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**regulation**" means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2. Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3. Authorization

The Board, in the exercise of its powers conferred by Part V and particularly sections 59 (1) and (2) of the Act, licenses the Licensee, subject to the terms and conditions set out in this Licence, to possess and control the business of Dubreuil Lumber Inc. including its distribution assets which are listed in Schedule 1 of electricity distribution licence No. ED-2012-0074, first issued to Dubreuil Lumber Inc. on March 5, 2012.

4. Term of Licence

4.1 This Licence will expire on October 2, 2019 unless the term of this Licence is extended by the Board.

5. Obligations under this Licence

5.1 The Licensee shall operate the electricity distribution assets referred to in section 3 in accordance with good utility practice.

5.2 The Licensee shall comply with all applicable Market Rules.

5.3 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act, regulations made under these statutes and all applicable orders or directives of the Board.

5.4 The Licensee shall provide, in the manner and form determined by the Board such information as the Board may require from time to time to monitor the Licensee's compliance with the conditions of this Licence.

5.5 Subject to the conditions of this Licence, the Licensee shall carry on, manage and conduct the operations of the distribution business in the name of the owner of the distribution assets, Dubreuil Lumber Inc. including:

(a) preserving, maintaining and adding to the property of the business;

(b) receiving the income and revenue of the business;

(c) issuing cheques from, withdrawing money from and otherwise dealing with the accounts of the business;

(d) retaining or dismissing employees, consultants, counsel and other assistance for the business;

(e) directing the employees of the business; and

(f) conducting, settling and commencing litigation relating to the business.

5.6 The Licensee may dispose of the distribution assets owned by Dubreuil Lumber Inc. as are ordinarily disposed of in the normal course of carrying on the business of a distributor.

6. Obligation to Comply with Codes

6.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the Licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

(a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

(b) the Distribution System Code;

(c) the Retail Settlement Code; and

(d) the Standard Supply Service Code.

6.2 The Licensee shall:

(a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

(b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

7. Obligation to Sell Electricity

7.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and as otherwise ordered by the Board.

8. Obligation to Maintain System Integrity

8.1 The Licensee shall maintain the electricity distribution assets referred to in section 3 in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

9. Liability of the Licensee

The Licensee is not liable for anything that results from taking possession and control of the distribution assets owned by Dubreuil Lumber Inc. or otherwise exercising or performing the Licensee’s powers and duties under the Act in relation to those businesses, this Licence or any order of the Board, unless liability arises from the Licensee’s negligence or wilful misconduct.

10. Provision of Information to the Board

10.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

10.2 Without limiting the generality of paragraph 10.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets referred to in section 3, as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

11. Customer Complaint and Dispute Resolution

11.1 The Licensee shall:

(a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

(b) publish information which will make its customers aware of and help them to use its dispute resolution process;

(c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee’s premises during normal business hours;

(d) give or send free of charge a copy of the process to any person who reasonably requests it; and

(e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

12. Market Power Mitigation Rebates

12.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

13. Communication

13.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

13.2 All communication relating to this Licence shall be in writing.

13.3 All communication is to be regarded as having been given by the sender and received by the addressee

(a) when delivered in person to the addressee by hand or by courier;

(b) ten (10) business days after the date of posting if the communication is sent by registered mail; and,

(c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

14. Copies of the Licence

14.1 The Licensee shall:

(a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours, as well as at the offices of the Township of Dubreuilville; and

(b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

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c embedded distributors to whom the distributor distributes electricity.

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Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

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i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

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The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

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