1-Staff-1

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

a) If so, please confirm whether a reply was sent by API in response to such comments and if so, please file copies of such responses with the OEB.
b) If not, please explain why a response was not sent and advise whether API intends to respond and file a copy of the response if and when such response is given.

RESPONSE:

API has not received any letters of comment as of the filing date of these interrogatory responses.

API intends to reply in writing to any such comments if and when received and will file copies with the OEB.

1-Staff-2

Updated RRWF

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), 12 (Residential Rate Design) and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

RESPONSE:

An updated RRWF has been filed as “API_IRR_RRWF_20190814.xlsm”. All changes impacting revenue requirement are documented on Sheet 14.

Sheets 10 and 11 have been updated to reflect the results of the updated Load Forecast and Cost Allocation models, which have been filed with these interrogatory responses as:

- API_IRR_TESI Load Forecasting Model_20190814.xls; and,
- API_IRR_Cost_Allocation_Model_20190814.xlsm

The values and calculations in Sheet 13 of the updated RRWF are consistent with Sheet 3 of API’s updated Rate Design Model, filed as “API_IRR_Rate Design Model_20190814.xlsx”. Sheet 12 of the RRWF is populated, however based on the response to 8-Staff-66, Sheets 6 and 6A of API’s Rate Design Model should be referenced instead. Further, the RRWF does not accommodate the rate design transition for API’s Seasonal rate class, and Sheet 7 of API’s Rate Design Model should be referred to for this adjustment.

1-Staff-3

Updated Bill Impacts

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated Tariff Schedule and Bill Impact model for all classes at the typical consumption / demand levels (e.g. 750 kWh for residential, 2,000 kWh for GS<50, etc.).

RESPONSE:

API has filed the following updated models:

- API_IRR_2020 Proposed Tariff_20190814.xlsx; and,
- API_IRR_Bill Impacts non-OEB Model_20190814.xlsx.

The updated Bill Impact model includes revisions to distribution rates resulting from the updated models filed in response to 1-Staff-2, as well as updates to RTSR rates and various rate riders, consistent with the updated RTSR Workform, LRAMVA model, and DVA Continuity Schedule filed in response to other interrogatories.

1-Staff-4

Ref: Exhibit 1 / s. 1.3.5 / pp. 14 – 17

Preamble:

API is requesting an alternative rate treatment for two ACM projects, 2021 Echo River TS project ($7.5M) and 2022 Sault Ste. Marie Facility ($14.1M), under the RRRP framework. API noted in the absence of this alternative approach, the rate rider for R1 customer for both projects would be $11/customer/month.

Questions:

a) Please calculate individual rate rider impacts for each of the two projects.
b) Through its customer engagement activities, did API communicate the need and impacts of these projects to its customers?
    a. If so, provide any feedback that was received as a result.
    b. If not, explain why?

RESPONSE:

a) Based on populating the OEB's ACM/ICM model consistent with information contained in the original application, and assuming recovery through a fixed rate rider, the rate rider impact by project is as follows:

Rate Class	Rate Rider (per customer, per month)	
	Echo River TS	SSM Facility
Residential – R1	$4.00	$7.15
Residential – R2	$223.70	$399.52
Seasonal	$2.01	$3.58
Street Lighting	$0.38	$0.67

ACM models aligned with the above rate riders have been filed as:

- API_IRR_ACM_Echo River_20190814.xlsm; and
- API_IRR_ACM_SSM Facility_20190814.xlsm

These models do not include adjustments for changes resulting from responses to other interrogatories, but would be updated as required when filed in a future proceeding. API also expects that any changes resulting from consideration of accelerated CCA, or any updates to align with the appropriate rate year would in incorporated in these future filings.

b) For the Sault Ste. Marie facility project, the Taking AIM surveys included a section designed to gauge customer feedback that would help inform API's long-term decision on facility renovation vs. replacement. See pages 51-52 of the Taking AIM report, which is included as Appendix B to the Business Plan in Exhibit 1. In Section 1.7.2 of Exhibit 1, API summarizes the customer feedback related to facilities investment in Table 18.

The benefits resulting from the Echo River TS project are only relevant to approximately half of API's customer base. Further, at the time of the surveys, API remained in discussion with Hydro One regarding analysis of options to address the supply point reliability risk. The taking AIM survey therefore did not mention the Echo River TS project by name, but did engage broadly on customer experiences and expectations with respect to reliability, as well as customer feedback on spending in the System Service investment category. In Section 1.7.2 of Exhibit 1, API summarizes the customer feedback related to System Service spending in Table 18.

1-Staff-5

Ref: Exhibit 1 / pp. 30 of 80 - Accounting Standard used in Application

Preamble:

On page 30 of Exhibit 1, API states the following:

> *"API has reported under the Accounting Standards for Private Enterprises accounting standard since January 1, 2011…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."*

Throughout the application, API has referred to the accounting standards used in its last rebasing application, as well as the ones used in every year subsequent to then, as MIFRS. OEB staff notes that MIFRS is underpinned by IFRS reporting standards, modified for various ratemaking considerations. API has never adopted IFRS for financial reporting or ratemaking purposes.

Questions:

a) Please confirm that API has prepared this application (including the presentation of all financial data from the years from 2015 to 2020) on the basis of ASPE standards, with the exception of capitalization and depreciation policies, which reflect those mandated by the OEB in 2013 (permitted in 2012). If this is not confirmed, please explain.
b) Please confirm that, throughout the application, API has interpreted the term MIFRS to mean: Any acceptable accounting standards (eg. ASPE/IFRS), as long as the capitalization and depreciation policies reflect those mandated by the OEB in 2013 (permitted in 2012). If this is not confirmed, please explain.

RESPONSE:

a) Confirmed.

b) Confirmed.

Exhibit 2

2-Staff-6

Ref: Exhibit 2 / DSP / p.26

Preamble:

API's DSP Section 2.2.1 provides information required under section 5.2.2a OEB's Chapter 5 and Section 2.2.3 provides information required under section 5.2.2d of the OEB's Chapter 5. However, there were no section in the DSP addressing requirements of section 5.2.2b and 5.2.2c of the OEB's Chapter 5.

Question:

Please provide information required by section 5.2.2b and 5.2.2c of the OEB's Chapter 5

RESPONSE:

5.2.2b

API continues to work collaboratively with HOSSM to resolve long term contingency response plans at the supply points indicated in Section 2.2.1.

Recent discussions with HOSSM have identified a range of options for resolving the contingency risk at Echo River TS, and API has included a project in 2021 for the installation of a second transformer that would allow restoration of the supply point at full capacity within 24-48 hours of a complete failure of the existing transformer. API continues to work with HOSSM to finalize the scope for the project in 2021, but the final scope is not available at this time.

API continues to work collaboratively with HOSSM on resolving similar issues at the Goulais and Batchawana supply points; however, there is currently uncertainty as to the timing, scope and costs of any related projects. As a result, a final deliverable is not available at this time.

5.2.2c

Through the annual stakeholdering meeting, API has reinforced the concerns with regards to the contingency plan and associated restoration time. More recently, API has shared the results of its customer engagement effort, where restoration time in excess of 4 hours would become a safety, security and potential health issue (see Appendix B, p.33)

2-Staff-7

Ref: Exhibit 2 / DSP / p.108

Questions:

a) Please explain System Renewal forecasted investment spikes in 2020 and 2023?
b) Please explain the System Service actual investment spike in 2019?

RESPONSE:

a) The increased forecasted investments in 2020 and 2023 are the result of the distribution substation rebuilds at the Dubreuilville #2 and Bruce Mines substations respectively. Project details for each are included in sections 4.4.3.V and 4.4.3.VI of the DSP.

b) The increased investment costs in the system service category in 2019 is to enhance the overall substation transformer contingency at the Desbarats, Bar River and Bruce Mines substations, following the 2018 failure of a power transformer at the Desbarats DS, as discussed in more detail at p.56 of the DSP.

2-Staff-8

Ref: Exhibit 2 / DSP / p. 11-12

Preamble:

API acquired approximately 350 customers of Dubreuiville Township in 2019 and Table 1-1 shows an expected increase in customers count in 2020

Questions:

a) Please update the table to show actual to date customer additions in the 2019 bridge and the remaining forecast for the 2019 and 2020 test years and explain any discrepancy in customer additions.
b) What is the reason for a significant actual winter and summer peak load increase in 2018 over the previous years?

RESPONSE:

a) The customer counts in Table 1-1 of the DSP are based on an average of 12 months, therefore considering year-to-date customer additions in 2019 would not be a valid comparison. API has instead included a 2019 YTD average customer count and an adjustment to include the customers acquired from DLI.

Rate Class	2018 Actual Average	2019 Forecast Average	2019 YTD Average	DLI 2019 YTD Average	2019 YTD with DLI	2020 Forecast Average
R1(i)	7640	7722	7694	312	8006	8116
R1(ii)	961	956	961	47	1008	997
R2	39	39	39	0	38	37
Seasonal	3076	3018	3032	0	3032	2960

API does not have any specific forecast for changes in customer count for the balance of 2019 or 2020, apart from the changes resulting from the trending included in the load forecast in Exhibit 3 of the application, which are aligned with the values in Table 1-1 of the DSP. In API's view, there are no material discrepancies between this trending and the 2019 year to date changes that would warrant a change to the forecasting methodology.

b) API observed increased load across all rate classes in 2018 due to atypical weather. 2018 20 HDD were 5% higher than the 2009-2018 average and 2018 CDD were 44% higher than average

2-Staff-9

Ref: Exhibit 2 / DSP / p. 24

Preamble:

Under section 2.1.6 of the DSP, API noted that it expects continued integration of business systems such as SAP, GIS, OMS, SCADA and VM [that] can provide improved analytical capabilities.

Questions:

a) Please explain what you mean by "continued integration" of the existing business system and what are the associated costs?
b) How was information from these different systems integrated in preparation of this DSP document and in performing Asset Condition Assessment (ACA) studies in Appendix J of the DSP?

RESPONSE:

a) The related material investment narrative at pages 146-148 of the DSP provides further information regarding integration of business systems. Examples of integration efforts prioritized for 2019 and 2020 include:
   i. Integration between the SAP billing system and the OMS to allow improved customer communication and notifications during outages;
   ii. Integration between the Vegetation Management System ("VMS") and GIS systems to avoid duplicate data entry that would otherwise be required to fully utilize the work planning and reporting capabilities of the VMS; and,
   iii. Mobile device integration to reduce effort associated with printing and updating of maps and records and other paper-based processes.

b) GIS data was used for spatial information regarding the distribution network in combination with a number of other data sources as follows:
   i. Loading information from the AMI system was integrated with the Engineering Analysis front-end of the GIS system to perform more accurate load allocations to support the planning study included as Appendix K to the DSP.
   ii. Data from the OMS system was integrated with system models from the GIS system to support the reliability study included as Appendix H to the DSP.
   iii. GIS data was used to support various inspection, testing and maintenance programs, the results of which underpin the Asset Condition Assessment.

2-Staff-10

Ref: Exhibit 2 / DSP / p.27-49 (all of section 2.3 of the DSP)

Preamble:

Section 2.3 of the DSP does not follow the prescribed format of the section 5.2.3 of the OEB's Chapter 5. Specifically, many of the measures or metrics specified in section 5.2.3a of the OEB's Chapter 5 were not provided in the DSP.

Questions:

a) Please provide measures and metrics for customer oriented performance, such as customer bill impact and power quality (not service quality)
b) Please provide measures and metrics for cost efficiency and effectiveness, such as physical and financial progress vs plan and actual vs planned cost of work completed
c) Please provide information regarding system line losses

RESPONSE:

Preamble: API considered the example metrics provided in of the Chapter 5.2.3(a) of the Filing Requirements to be possible metrics to be considered by the LDC, but that the final selection of metrics was at the LDC's discretion, so long as they covered the required categories of customer-oriented performance, cost efficiency and effectiveness, and asset/system operations performance. To that end, API provided 4-8 metrics for each of these three categories, as summarized in Table 2-2 on page 27 of the DSP. For the convenience of the reader, the remainder of Section 2.3 of the DSP is organized by Performance Measure (i.e. groupings of 1-3 Performance Metrics), and the information required by Sections 5.2.3a through 5.2.3c of the Chapter 5 Filing Requirements is provided for each Measure, as clearly referenced in each subheading.

a) 8 metrics relating to customer-oriented performance are reviewed in detail on pages 28-42 of the DSP. API does not track power quality as a performance metric. With respect to bill impact, API notes that the distribution rates for the majority of its customers are adjusted annually in accordance with a RRRP adjustment factor, meaning that these rates are not linked to costs in the DSP. For the Seasonal and Street Lighting rate classes (i.e. the two rate classes not eligible for RRRP), 2015-2019 rate adjustments were largely driven by significant changes to revenue-to-cost ratios resulting from the 2015 rate application, rather than anything in the DSP.

b) 6 metrics relating to cost efficiency and effectiveness are reviewed in detail on pages 43-48 of the DSP. Table 2-11 in this section provides information on project progress vs plan for the System Renewal category and discussion on plan vs actual for other categories was included at the bottom of page 47, with references to other sections of the DSP where appropriate. Section 4.3 of the DSP includes detailed plan vs actual cost analysis for the 2015-2019 period.

c) This information was provided at page 49 of the DSP.

2-Staff-11

Ref: Exhibit 2 / DSP / p.50

Preamble:

The three key principles listed as integral to AMP only include customer-focused ones without any mentioning of the principles in other Performance Outcomes in Table 3-1.

Question:

Please explain the difference between "key principles" and other principles contained in Table 3-1.

RESPONSE:

The objectives and principles listed in the second column of Table 3-1 on page 51 of the DSP are one as the same as those described in the paragraphs on page 50 of the DSP. The use of the term "key principles" to introduce the list of three customer-focused principles on page 51 should be read as emphasizing the importance of customer-focused outcomes. It should not be interpreted as minimizing the importance of other objectives and principles in any of the preceding or following paragraphs on page 50.

2-Staff-12

Ref: Exhibit 2 / DSP / p.52

Question:

Is there are a formal quantitative prioritization step for discretional project in the AM Process shown in Figure 3-1?

RESPONSE:

API prioritizes projects based on the criticality of the investments with consideration to any applicable criteria listed in the “Annual Budget Consideration” in Figure 3-1. Generally, projects to replace certain end-of-life assets in advance of failure are given high priority to allow for a paced and sustainable replacement program that levelizes annual spending by asset type to the extent possible, and results in efficient use of internal resources. Consideration is then given to general plant items, to ensure that annual spending on critical items such as fleet, buildings, computer hardware/software, tools and test equipment, etc. is sufficient to support day-to-day business and operations activities. Any remaining projects that are more discretionary in nature are evaluated according to any applicable criteria listed in the “Annual Budgeting Consideration” section of the above flowchart.

2-Staff-13

Ref: Exhibit 2 / DSP / p.62 and Appendix J/p.25

Preamble:

API stated that it owns 28,104 wood poles within its service territory. There also exists 2,007 wood poles owned by Bell and Hydro One Sault Ste. Marie within API's service territory for a total of 30,111.

Questions:

a) Do capital and inspections plans presented in the DSP address only API owned poles or also include joint use poles owned by third parties?
b) Was any intrusive testing other than visual inspections, e.g. using resistograph or other methods, done for wood poles? If "no" how was wood poles remaining strength estimated in the ACA?

RESPONSE:

a) Capital replacement projects apply to both API assets and API assets on Bell owned poles.

b) API retains a third-party contractor to perform pole testing. Typical testing includes visual inspection of each pole, hammer sound test and, if a pole is suspected of internal decay, a resistogragh is performed. Predictive analysis is used by the pole testing contractor to estimate the remaining strength and these results were incorporated in the ACA.

2-Staff-14

Ref: Exhibit 2 / DSP / p.61-62

Preamble:

Percentages of wood poles in all 5 condition bands shown in Table 3-4 do not translate into the corresponding numbers of units shown in Figure 3.8.

Question:

Please provide a reason for discrepancy and what the correct numbers should be?

RESPONSE:

The health index distribution for wood poles presented in Table 3-4 represent the distribution of inspected poles only (see Figure 3.2 of Exhibit 2 /DSP /Appendix J). The corresponding pole quantities in Figure 3.8 represent the extrapolated values for the wood poles. The corrected values (to one decimal point) are show in the table below.

Asset Category	Health Index Distribution (%)				
	Very Good	Good	Fair	Poor	Very Poor
Wood Poles	50.2%	40.3%	7.0%	0.3%	2.2%

2-Staff-15

Ref: Exhibit 2 / DSP / p.75 and Appendix J

Preamble:

Health Index distribution for wood poles in the ACA contained in Appendix J of the DSP shows extrapolated number of wood poles in very poor and poor condition to be 620 and 96 respectively. At the same time, the target replacement rate for wood poles is 500 per year. At this rate all very poor and poor poles will be replaced in just over 1 year and all of the fair poles in another four years.

Questions:

a) Please explain the reason for deciding on 500 pole per year replacement rate given the results of the ACA?
b) Please provide a unit cost per pole for this pole replacement program and contrast with historic costs per pole replacement.

RESPONSE:

a) API's decision to keep its pole replacement rate at 500 poles per year is based on the recommendations from the ACA (DSP Appendix J). API has a large amount of poles past their TUL (see ACA Table 5-3), and maintain the approach of proactively replacing poles prior to failure, it was recommended to replace between 450 and 660 poles annually depending on the outcome of further visual inspections. API chose 500 poles as its annual target replacement rate to meet the ACA recommendation, as well as to maintain its current target replacement rates consistent with the it's the expectations of its customers for System Renewal capital investment (see DSP Appendix B, P.42).

   This recommendation and overall approach is also in line with API's long-term end-of-life asset replacement planning process (see DSP Appendix C, p.30, P.32). API regularly reviews condition assessments, inspections, testing results, failure rates, age profile, etc. of its poles asset to determine the appropriate level of sustainment. The goal is to replace these assets on an end-of-life basis with annual expenditures for each asset group levelized to the extent possible.

b) Please see the table below for the unit cost comparison:

	Unit Cost per Pole	
	2020-2024 Program	2015-2019 Historical
Distribution Line Rebuild	$ 7,500	$ 7,620
Express Feeder Rebuild	$ 10,000	$ 9,739

2-Staff-16

Ref: Exhibit 2 / DSP / p.84

Question:

Please explain the $88k increase in express feeders and $217k in line rebuild for a total cost increase of $305k between 2020 and 2021.

RESPONSE:

API's 2020 forecasted expenditures for express feeder and line rebuilds is based on planned projects listed in Table 4-8 on Page 123, while the forecasted expenditure for 2021 is based on the rolling average cost per pole multiplied by the target annual replacement rate.

2-Staff-17

Ref: Exhibit 2 / DSP / p.64-65

Questions:

a) Please confirm that no Heath Index distribution was provided for overhead switches and reclosures due to the lack of condition data.
b) Please indicate whether API intends to follow the recommendations in the ACA report contained in Appendix J of the DSP to start collecting relevant condition data for these assets.

RESPONSE:

a) No health index was provided for overhead switches and reclosers due to the lack of condition data.

b) API intends to better capture recloser condition data during planned maintenance work. API does not intend to collect condition data for the majority of its overhead switches, since they are either immediately replaced if issues are observed during inspections, or are otherwise run to failure as discussed at the reference above. For more critical gang-operated switches in substations and on critical lines, API performs visual inspections and infrared scanning on a regular basis and the result. Issues with these switches are typically addressed through either cyclical maintenance or immediate corrective action, such that the effort to compile a Health Index would add little value.

2-Staff-18

Ref: Exhibit 2 / DSP / p.61, 66, 67 and Appendix J

Preamble:

Table 3-4 shows Health Index distribution for different numbers for station power transformers (10), spares and voltage regulating transformers (21) and ratio banks (3) than what is shown in the ACA report in Appendix J and in Figures 3.13 and 3.14 of the DSP.

Questions:

a) What is the correct number of station power transformers for which a Health Index was calculated?
b) What is the correct number of spares and voltage regulating transformers for which a Health Index was calculated?
c) What is the correct number of ratio banks for which a Health Index was calculated?

RESPONSE:

Preamble: Table 3-4 as included in the DSP was inadvertently not updated to match the final ACA report.

a) The correct number of station power transformers for which a Health Index was calculated is 13.

b) The correct number of spares and voltage regulating transformers for which a Health Index was calculated is 18.

c) The correct number of ratio banks for which a Health Index was calculated is 3.

2-Staff-19

Ref: Exhibit 2 / DSP / p.69 and Appendix K of the DSP

Preamble:

Tables 3-5 and 3-6 do not show any distribution or transmission stations with loading exceeding their thermal capacity while the Planning Study in the Appendix K of the DSP lists a number of stations operating at more than 100% of their thermal capacity (not related to voltage issues) under normal operating conditions.

Question:

Please explain reasons for the difference between information shown in Tables 3-5 and 3-6 of the DSP and results of the Planning Study contained in Appendix K of the DSP for normal operating conditions?

RESPONSE:

The stations operating at over 100% capacity listed in the Planning Study in Appendix K of the DSP is actually a set of ratio banks (WawaSD9400) and the contingency backup to this bank (Wawa2T2). Table 3-5 does not include the ratio bank transformers, as they are located outside of the station.

2-Staff-20

Ref: Exhibit 2 / DSP / p.71 and Appendix E of the DSP

Preamble:

A need for Echo River TS second transformer was identified in the Regional Planning study led by Hydro One shown in Appendix E of the DSP. However, the letter states that API's capital contribution amount has not been determined yet.

Questions:

a) Please indicate what API's final capital contribution amount is expected to be?
b) What is the basis for the costing of installation of a second transformer at Echo River TS, i.e. how many different bids have been evaluated and provide reasoning for rejecting those bids?
c) What are the costs of other alternatives being considered, e.g. reinforcement of the feeder NA1?

RESPONSE:

a) At this stage, API has forecasted that it will be required to contribute 100% of the estimated project cost provided by Hydro One, or $7.5 million based on the mid-point of the estimate range. As indicated in the most recent Regional Planning Status Letter (see Appendix E of the DSP), discussions surrounding cost responsibilities and capital contributions from API are ongoing and will be consistent with the Transmission System Code.

b) The costing is based on initial cost estimates from Hydro One.

c) The following options were considered:

Option	Option Description	Estimated Capital Cost from API ($M)	Estimated Restoration Timeframe
1	Status quo	0	5-6 months
2	Cold Spare @ Echo River	2 - 3	6-8 weeks
3	Hot Spare @ Echo River	6 - 9	24-48 hours
4	DESN @ Echo River	12 - 18	<4 hours
5	Double 34 kV Circuit from SSM to Bar River DS	8 - 9	<4 hours

2-Staff-21

Ref: Exhibit 2 / DSP / p.71 and Appendix E of the DSP

ACM Model/Sheet 10

Preamble:

API's 2015-2019 DSP, submitted during its last rebasing application, included the Echo River TS upgrade at a forecasted costs of $4.55 million. In the current application, API has requested ACM treatment for the same project at a forecasted cost of $7.5 million.

Questions:

a) Please provide all documentation and minutes of discussions with API's Board of Directors, Hydro One Sault Ste. Marie (HOSSM) and/or Great Lakes Power Transmission (GLPT) pertaining to the Echo River Transformer Station.
b) Provide further justification of the delay for this project, initially planned in 2017.
c) Please explain the increased cost estimate for this transformer over a three year period.

RESPONSE:

a) The requested documentation with respect to HOSSM and GLPT has been filed as "API_IRR_2-Staff-21_Echo River Documents.pdf". Please refer to 1-SEC-1 for detail on the material provided to API's Board of Directors, which includes consideration of the Echo River TS upgrade as an ACM project as part of the approval of the application.

b) As discussed in Sections 2.1.7 and 2.2.1 of the DSP, API had initiated discussions with GLPT at the time of preparing its last DSP, and the need for a solution was included in the 2014 Needs Assessment Report resulting from the Regional Planning process. Prior to committing to the Echo River project, GLPT began investigating additional options for short-term and long-term contingency response plans and providing updates to API at annual stakeholder meetings. Subsequent to GLPT's sale of its transmission business to Hydro One in late 2016, API worked with HOSSM to review progress on contingency planning, and to consider any other options that may be appropriate in consideration of Hydro One's larger fleet of spare equipment and Mobile Unit Substations (MUS). These efforts determined that equipment available to Hydro One was not a match for the 34.5 kV supply voltage at Echo River TS. API subsequently worked with Hydro One to identify various contingency options and related configurations for the Echo River TS. Hydro One, as the owner and operator of the substation, also put additional effort into providing cost estimates for each option, as well as estimates of restoration times following the loss of the existing transformer. These options are summarized as options 1-4 in response to 2-Staff-20(c). API determined that the 6-8 week estimated restoration time for the “cold spare” option was unacceptable in terms of long-term contingency risk management, and that a “hot spare” with a 24-48 hour restoration would be the most appropriate option.

API maintains the position put forward in its previous DSP that a transmission solution is preferable to a distribution solution, based on the significant technical disadvantages of the distribution alternative summarized on pages 70-71 of the DSP.

c) Since this substation is owned by the transmitter, API is required to work with the transmitter to obtain the cost estimates for any modifications or upgrades. The $4.55 million estimate included in the 2014 DSP is supported by an estimate provided from GLPT to API in late 2011, which has been filed in response to part a). API notes that this previous estimate had not been adjusted for inflation to 2017 in its previous DSP. In the course of preparing the current DSP, Hydro One provided API with an initial budgetary estimate range of $6-9 million, which would be refined upon further engineering. API used the mid-point of this range ($7.5 million) for the purpose of its current DSP. Once API receives further detail from Hydro One, it expects to work collaboratively with Hydro One to ensure that the capital cost to be contributed by API is consistent with the minimum scope required to achieve appropriate contingency restoration times.

2-Staff-22

Ref: Exhibit 2 / DSP / p.71

Question:

Please list contingency plans provided by GLPT/HOSSM that would effectively limit the station capacity to 5 MVA?

RESPONSE:

GLPT/HOSSM has not provided a formal contingency plan for the Goulais TS, but had previously identified through discussions the possibility of relocating a smaller capacity transformer from another station (1.667MVA rated capacity) in the event of a failed transformer at this station. The resulting capacity would be limited by the smaller transformer.

2-Staff-23

Ref: Exhibit 2 / DSP / p. 84

Preamble:

Bruce Mine DS and Dubreuiville #2 DS rebuild shown in Table 4-2 addresses needs in System Renewal and System Access categories.

Questions:

a) Please identify the main driver and percentage of the total cost associated with it for Bruce Mine DS and Dubreuiville #2 DS rebuild/expansion projects?
b) Please indicate where detail business cases showing comparison of received bids and costing of other alternatives for each of the projects can be found in application or provide them.

RESPONSE:

a) The main driver for both the Bruce Mines DS and Dubreuilville #2 DS rebuild projects is asset renewal and accounts for 100% of the total costs associated with it.

b) API is currently working on the alternative analysis for the Dubreuilville #2 DS and intend to tender the result of the preferred alternative as an Engineering, Procurement and Construction contract. API intends to perform the same type of comparison/study for Bruce Mines DS in 2022.

2-Staff-24

Ref: Exhibit 2 / DSP / p.87

Question:

Please explain the $227k cost of IT hardware in 2020 as shown in Table 4-4

RESPONSE:

Please see response to 2-VECC-13(b).

2-Staff-25

Ref: Exhibit 2 / DSP / p. 87 and 90

Preamble:

Table 4-4 on page 87 of the DSP shows the costs of maintaining API's fleet to be around $650k per year while section 4.1.2.4.4 of the DSP states that the fleet costs are comprised of purchasing a Line/Forestry truck at $275-400k plus $150k annually to cover replacement of smaller vehicles.

Question:

a) Please explain the $100k difference between fleet expenses shown in Table 4-4 and explained in section 4.1.2.4.4.

RESPONSE:

a) The additional $100k is intended for the replacement of miscellaneous fleet equipment (trailers, forklifts, etc.) and vegetation-specific fleet equipment (chipper, dually-truck).

2-Staff-26

Ref: Exhibit 2 / DSP / p.102

Preamble:

Section 4.1.4.1 refers to Table 3-4 in Section 3.2.4. Table 3-4 is actually in section 3.2.3 and shows API Health Index distribution and there is no Table 3-4 in Section 3.2.4 of the DSP.

Question:

Please confirm that API means table 3-6 instead of 3-4?

RESPONSE:

That is correct, section 4.1.4.1 should reference Table 3-6 instead of 3-4.

2-Staff-27

Ref: Exhibit 2 / DSP / p.104 and 105

Question:

What is the methodology used for prioritizing substation projects on a case-by-case basis (p.104)?

RESPONSE:

As described in section 4.3 and 4.4 of API's Asset Management Program, API performs predictive, corrective and preventative maintenance for all of its substations and equipment contained within each substation. The results of these activities allows API to understand the state of the infrastructure within each of its stations. Having completed an initial Asset Condition Assessment ("ACA"), which is filed as Appendix J to the DSP, API intends to perform further analysis of the results, implement certain recommendations for augmenting condition data, and update the ACA to further aid in planning and prioritizing projects within each station.

API also considers modernization drivers when planning substation projects, such as operational improvements, equipment upgrades, reliability improvements, etc. Many System Service projects in the DSP reflect recommendations from the third-party Substation Refurbishment and Modernization Plan, which considers the results of the ACA, as well as other studies included as Appendices to the DSP. Long-term system planning through distribution planning studies (see Appendix K to the DSP) also allows API to ensure that the capacity and rating of equipment will meet the forecasted load and demand.

2-Staff-28

Ref: Exhibit 2 / DSP / p. 123 and 138

Question:

Why is the $524k for 2020 shown in table 4-14 for protection, automation and reliability within System Service investment category not included in Table 4-8 which shows the total of System Service Investment category of $512 in 2020?

RESPONSE:

Table 4-14 included the entire amount of planned protection, automation and reliability investments as a material line item. In contrast the amounts in Table 4-8 included material individual investments within this program, but omitted approximately $12k in non-material items. The non-material amount would typically be used for reactionary work, for example replacing a fused cut-out or hydraulic recloser with an electronic version, to resolve a coordination issue that cannot be resolved by simply changing the size of the existing fuse or recloser trip coil.

2-Staff-29

Ref: Exhibit 2 / DSP / pp. 149 - 151
Exhibit 2 / Appendix M / p.

Preamble:

API notes that its current facility at 2 Sackville Road in Soult Ste. Marie is subleased from Hydro One Sault Ste. Marie, which whom it currently shares the site and buildings. API notes that it assessed options and costs associated with extending this lease as compared to constructing its own facility.

Questions:

a) Please provide a copy of the Applicant's formal business case for the new facility and provide the proposed location of the facility.
b) Please provide a copy of all materials provided to the applicant's Board of Directors in approving the proposed Facility in Sault Ste. Marie.
c) Please state which other options have been explored and provide a breakdown of the total costs of each option and compare with the total estimated capital cost proposed for ACM treatment in this application.
d) API notes efficiency gains as a primary driver for this project. Please highlight those efficiencies and explain how they have been reflected in this application.

RESPONSE:

a) The Business Case, with other supporting documentation included as appendices, has been filed as "API_IRR_2-Staff-29_SSM Facility Documents.pdf".

b) Summary information from Exhibit 1 of the application, including discussion of the ACM projects as filed, was presented API's Board of Directors, along with instructions on how to access the entire application. Please see response to 1-SEC-1 for complete details on the material contained in the Board package.

c) API considered three options other than the proposed New Facility – continuing to operate in the current facility on Sackville Road without any changes or updates (the "Status Quo" option), finding a new site and leasing that space or negotiating a lease-to-own agreement, and continuing to operate at the Sackville Road location while investing in significant capital upgrades (the "Brownfield" option) which aligns with the deliverables of the new space as closely as possible.

   In the **Status Quo option**, there would be no capital upgrades, beyond required work to address building deficiencies as identified in a facility Condition Assessment Report cosponsored by API and their landlord Hydro One (the Elliott Engineering report). Those upgrades would be translated into a new lease offered to API to continue to operate at Sackville Road, with API's proportion of the costs to be negotiated in the terms of the lease. The annual cost of a new lease has been calculated to be $926,721 in the first year of the new term (2020), based on several assumptions, including:

i) A 20-year lease term, with capital upgrade costs shared equally with the landlord over that term as per accepted depreciation calculations for such investments
ii) Application of the identified Market Lease Rates for API's occupied spaces
iii) Addition of Vacant Land lease cost, which is not a part of the current lease but has been identified as a factor to be incorporated in any new agreement
iv) Utilizing a 2% Cost-of-Living increase per-year calculation on current lease amount, to extrapolate annual maintenance costs starting in 2020

With regards to the **Leasing option**, API conducted a search of possible available sites in Sault Ste Marie, with the help of a consultant and real estate representative. Nine (9) potential sites were identified, and subsequently investigated, using the same criteria that was developed for analysis of available sites to build a new fully integrated facility.

Through the investigation, API determined that none of the sites were suitable. Issues included the site not being compatible to house the entire API operation (Administrative and Operational needs) – either due to constraints on available space or the requirement for significant capital investment to align the site with API's operational needs – and sites not currently being available.

For the **Brownfield option**, construction costs associated with adding/upgrading facilities total $10,124,200. Those costs include:

i) $[redacted] in renovations to the existing Administrative Building
ii) $[redacted] to build a new Operations area (Stores, Repair and Wash Bays, Metering & Electrical work area, Crew mustering spaces and Equipment Storage
iii) $[redacted] to build a new Fleet Garage

iv) $[redacted] for Design and Construction contingency, as per accepted project practice

v) $[redacted] for Site Development

Additional costs include internal labour and external consultant fees ($200,000), an estimated $150,000 to relocate existing Transmission lines that are in the construction zone, and an estimated $1,000,000 for furniture, fixtures, equipment and temporary relocation costs to facilitate renovations and construction. This brings the overall capital investment to $11,474,200.

There are also unquantified costs associated with this option, including potential environmental remediation and addressing easement constraints.

d) Efficiency gains are outlined in API's Business Case document and are referred to in the DSP (see page 150). Those gains are to be achieved through the design and construction of a fully integrated new facility that will take all operational aspects of API's business into account and formulate a proper workflow strategy.

2-Staff-30

Ref: Exhibit 2 / DSP / pp. 149 - 151
Exhibit 2 / Appendix M

Questions:

a) Please provide the plan showing the layout of the new facility.
b) Please provide a breakdown between land purchase and building costs.
c) What is the total square feet of the proposed facility?
d) What is the actual square feet per person of new facility?
e) Please provide the i) gross square feet per employee, ii) capital cost per employee, and ii) capital cost/gross square feet.
f) Please provide any proposed meeting space in square feet.
g) Is API expecting to lease out any available space to a third party? If so, please provide an estimated revenue off-set.
h) If this information is not available, please provide an estimate as to when API expects to file this information.

RESPONSE:

a) Please see pages 3-5 of MGP's Master Facility Plan for Algoma Power Inc., which is included in the reports filed in response to 2-Staff-29(a)

b) API estimates the land acquisition cost for the preferred development site to be $[redacted]. Construction costs are estimated at $[redacted].

Please see MGP's Master Facility Plan for Algoma Power Inc. (page 6) for construction cost breakdown, and API's Business Case (page 19) for a full cost breakdown.

c) 41,703 square feet including office space, material storage room, indoor garage, and workshop.

d) 631 square feet per person (34,705 actual square feet / 55 FTE)

e) The breakdowns requested are as follows:

i) 758.2 square feet per person (41,703 gross square feet / 55 FTE)

ii) $256,690.90 per employee ($14,118,000 / 55 FTE)

iii) $338.54 per square foot ($14,118,000 / 41,703 sq.ft.)

f) Please see Appendix M of the DSP (page 12-15):

Board Room – 400 square feet

Training Room – 760 square feet

Customer Service Meeting Room – 200 square feet

Common/Shared Meeting Room 1 – 200 square feet

Common/Shared Meeting Room 2 – 300 square feet

Total Meeting Space square footage = 1860.

g) API does not expect to lease out any space to a third party. API's program space has been developed to address its operational needs across all departments as well as common space requirements. This development has passed through several iterations to ensure the overall footprint reflects essential needs only. The total has been reduced from an initial estimate of 52,771 square feet to its final version of 41,703 square feet.

h) All information has been provided through the responses above and the reports referenced above.

2-Staff-31

Ref: Exhibit 2 / DSP / pp. 142 -143
Exhibit 2 / DSP / pp. 149 – 151

Questions:

a) Please provide a calculation showing the increase in RRRP funding amounts for each of the ACM project over the IRM term using API's proposed 2020 parameters.
b) Provide a calculation of the rate riders for the non-RRRP eligible rate classes and estimated bill impacts.

RESPONSE:

a) The following calculation details the RRRP funding amounts required for each ACM project, based on the ACM models filed in response to 1-Staff-4(a):

Ref	Description	Echo River	SSM Facility
A	Incremental revenue allocated to R1 rate class	437,959	782,160
B	Incremental revenue allocated to R2 rate class	100,082	178,739
C=A+B	Annual incremental RRRP revenue	538,041	960,899
D	# of rate years until next rebasing	4	3
E=C*D	Total RRRP funding	2,152,164	2,882,697

b) Please see the response to 1-Staff-4(a) for the calculation of rate riders. The bill impacts resulting from these rate riders for the non-RRRP eligible rate classes are as follows:

Rate Class	kWh	Total Bill[i]	Rate Rider Impact[ii]	% Bill Impact
Seasonal	50	$78.88	$5.87	7.4%
Seasonal	153	$112.57	$5.87	5.2%
Seasonal	750	$309.65	$5.87	1.9%
Street Lighting	3308	$1,688.38	$1.10	0.07%

[i] From Exhibit 8, Table 15
[ii] The total of the two rate riders from 1-Staff-4(a) are increased by 5% to reflect the net effect of 13% HST less the 8% rebate

2-Staff-32

Ref: Exhibit 2 / s. 2.3.3 / p. 17
Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 to October 31, 2019

Question:

Please update the cost of power calculation using the latest OEB Report as referenced above.

RESPONSE:

Cost of power has been updated to reflect the OEB report as referenced above. API also updated RPP percentages based on 2018 RRR filing data, and updated 2019 and 2020 volumes for consistency with the updated Load Forecast model filed with these interrogatory responses. An updated Appendix 2-Z has been filed as “API_IRR_2-Staff-32_Cost of Power(2-Z).xlsx”.

2-Staff-33

Ref: Appendix 2-G

Preamble:

The table below shows a decrease in the service quality for written response to enquiries from 100% in 2017 to 81.2% in 2018 and emergency rural response has decreased from 100% in 2017 to 95.7% in 2018.

Service Quality

Indicator	OEB Minimum Standard	2014	2015	2016	2017	2018
Low Voltage Connections	90.0%	100.0%	100.0%	99.4%	99.2%	98.6%
High Voltage Connections	90.0%	n/a	n/a	n/a	n/a	n/a
Telephone Accessibility	65.0%	82.6%	81.9%	86.6%	80.1%	86.1%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	83.3%	81.2%
Emergency Urban Response	80.0%	n/a	n/a	n/a	n/a	n/a
Emergency Rural Response	80.0%	100.0%	100.0%	100.0%	100.0%	95.7%
Telephone Call Abandon Rate	10.0%	4.8%	6.2%	3.8%	7.4%	8.3%
Appointment Scheduling	90.0%	97.2%	94.9%	98.2%	97.1%	99.0%
Rescheduling a Missed Appointment	100.0%	n/a	n/a	n/a	n/a	n/a
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Questions:

a) Please explain why API's service quality for written responses to enquires and emergency rural response has declined and what steps have been taken to rectify the issues.

RESPONSE:

a) In 2017, API revised its process with respect to written response reporting to use work order tracking through its CIS system in order to better manage correspondence and improve service levels. As part of the revised process, providing a customer with an offer to connect, following the receipt of a connection application, was included as a newly implemented written response. After reviewing performance trends following this change, API determined that due to the rural nature of its distribution system, the time required to arrange an appointment, complete and review the service layout and associated cost estimate and return the offer to connect to the customer occasionally exceeded the 10-day window. As of October 2018, API implemented a process to send an initial written response to customers applying for a new service. This initial response is sent within the 10-day window to confirm receipt of the connection application, confirm the appointment date of the in-person site visit, and provide other general information on the process. As a result of this change, API expects 2019 performance levels to improve.

The 2018 emergency rural response result of 95.7% is due to a single event where API was unable to respond on-site within 120 minutes. In this particular case, API's on-call crew received a call at approximately 2 am from the OPP reporting a large tree on API's lines. The crew had already been dispatched to another power outage call that had not been reported by emergency services and proceeded to respond to both calls in the order received since there was no basis for prioritizing the call reported by the OPP over the first dispatch. Consistent with the definition of "emergency call" in the DSC, API records its response to all requests for assistance from emergency services in its RRR filings, regardless of the severity of the situation.

Exhibit 3

3-Staff-34

Ref: Exhibit 3 / Appendix 2-H

Question:

Other revenues due to late payment charges have declined by 63% from OEB-approved amounts of $89,000 to a forecasted $33,000 in the test year. Please explain why.

RESPONSE:

The late payment account includes late payment, notification and collection of account charges in accordance with the Tariff of Rates and Charges. Overall decline in revenue is related primarily to the OEB Decision and Order restricting winter disconnection introduced in 2017. Furthermore, per the generic rate order issued on March 14, 2019, effective July, 2019, the OEB eliminated all Collection of Account charges, and this added to the additional reductions in revenue.

3-Staff-35

Ref: Exhibit 3 / Appendix 2-H

Question:

API noted that the increased revenues in 2018 in Account 4220 relate to a one-time CDM mid-term incentive payment. Please provide further explanation regarding this payment.

RESPONSE:

For the Conservation First Framework ("CFF") 2015 – 2020, the Independent Electricity System Operator ("IESO") provided mid-term incentive ("MTI") payments to LDC's who selected achieved full cost recovery funded verified electricity savings as of December 31, 2017, which were equal to or greater than their MTI Threshold. For LDC's in Joint CDM Plans to be eligible for the MTI, the Joint CDM Plan must have achieved in aggregate full cost recovery funded verified savings as of December 31, 2017, which are equal to or greater than their aggregate MTI Threshold.

Algoma Power Inc. was in a joint plan with Canadian Niagara Power Inc. and met their aggregate MTI Threshold.

3-Staff-36

Ref: Exhibit 3 / Appendix 2-H

Question:

API forecasts a revenue of $25k in interest and dividend income. That is a decline of 53.7% over 2015 actuals. Please explain and provide the year to date revenue and compare to the equivalent time period in 2018.

RESPONSE:

OEB 4405 has fluctuated year-over-year and is dependent on bank and affiliate loan balances, interest rates, and regulatory account balances. Given the unpredictability of the account, the $25,000 represents an average of the interest income, other than regulatory interest, for 2015 to 2018. A zero dollar value was included in the 2020 Test Year for regulatory interest income because the average of regulatory interest income recorded in OEB 4405 (in Appendix 2-H) and regulatory interest expense recorded in OEB 6035 for the 2015 to 2018 period was a net debit of $3,899. See table below for calculation of net regulatory interest expense for 2015 to 2018 period.

	OEB Acct	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Average
Regulatory Interest Income	4405	-$ 23,369	-$ 13,630	-$ 9,843	-$ 16,581	-$ 15,856
Regulatory Interest Expense	6035	$ 30,862	$ 10,448	$ 10,574	$ 27,135	$ 19,755
Total		$ 7,493	-$ 3,182	$ 731	$ 10,554	$ 3,899

The total OEB 4405 June year to date revenue was $21,045 in 2018 and $29,026 in 2019.

3-Staff-37

Ref: Load Forecasting Model / Tab Input – Adjustments & Variables

Preamble:

API has included the following Adjustments to Wholesale Purchases:

1. Richmount_Total
2. Dubreuilville
3. Bonifero
4. Searchmont
5. TrapRock 1
6. TrapRock 2

The formula for the Revised Wholesale Purchases in the excel column J subtracts the last two adjustments from the Unadjusted Wholesale Purchases kWh. The first four are not used to adjust Wholesale Purchases.

Questions:

a) Does the unadjusted wholesale purchases include embedded generation? If not, please explain how this is captured.
b) Please explain the purpose of each of the six Adjustments to Wholesale Purchases.
c) Please explain why the first four were not used in arriving at the Revised Wholesale Purchases.

RESPONSE:

a) Please refer to the response to 3-VECC-17(c).

b) Please refer to the response to 3-VECC-17(d).

c) Please refer to the response to 3-VECC-17(d).

3-Staff-38

Ref: Exhibit 3 / s. 3.1.8 / p. 22
Load Forecasting Model / Tab Forecast

Preamble:

The Filing Requirements state that "If monthly Heating Degree Days (HDD) and/or Cooling Degree Days (CDD) are used to determine normal weather, the monthly HDD and CDD based on: a) 10-year average and b) a trend based on 20-years. If the applicant proposes an alternative approach, it must be supported."

API has provided a table with 20 years of HDD and CDD. Two columns are provided for "10 year avg" and "20 year avg."

The HDD and CDD used to forecast 2019 and 2020 wholesale purchases are different, and do not match either the 10-year or 20-year average.

HDD

	2019 forecast	2020 forecast	10-year average	20-year average
January	866.46	872.27	873.3	856.0
February	777.38	780.24	776.2	765.7
March	702.90	689.68	690.6	691.8
April	467.66	460.08	464.6	442.6
May	242.01	230.01	237.7	240.6
June	108.81	103.50	105.5	99.4
July	43.14	34.34	39.9	37.0
August	42.49	36.87	41.7	41.4
September	122.60	127.69	128.5	127.3
October	319.71	315.97	322.4	325.5
November	487.47	486.83	485.4	487.3
December	726.82	699.36	722.1	721.3
Total	4,907.44	4,836.84	4,886.8	4,835.9

CDD

	2019 forecast	2020 forecast	10-year average	20-year average
January	0.00	0.00	0.0	0.0
February	0.00	0.00	0.0	0.0
March	0.00	0.00	0.0	0.0
April	0.02	0.02	0.0	0.0
May	4.02	5.07	4.5	3.5
June	9.02	9.15	10.5	15.4
July	37.68	42.02	40	44.7

August	35.76	38.11	36	33.7
September	13.69	14.60	12.9	14.7
October	0.38	0.42	0.3	0.8
November	0.00	0.00	0.0	0.0
December	0.00	0.00	0.0	0.0
Total	100.57	109.39	104.1	112.9

Questions:

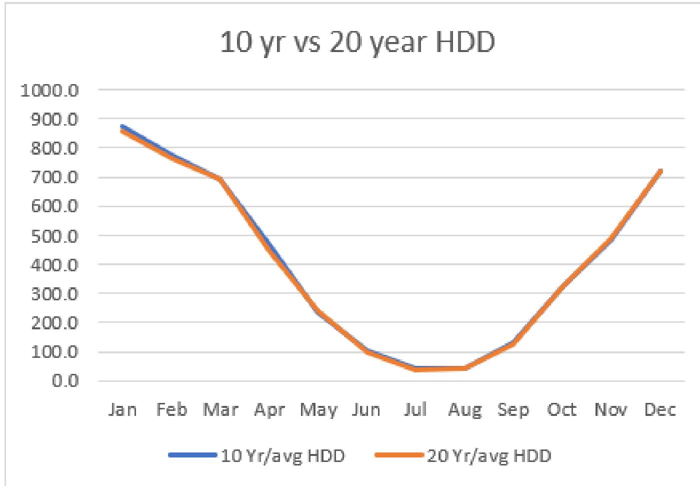
a) Please provide the 20-year trend of HDD and CDD.
b) Please reconcile the HDD and CDD used to calculate the 2019 and 2020 forecasts with the 10-year or 20-year average.

RESPONSE:

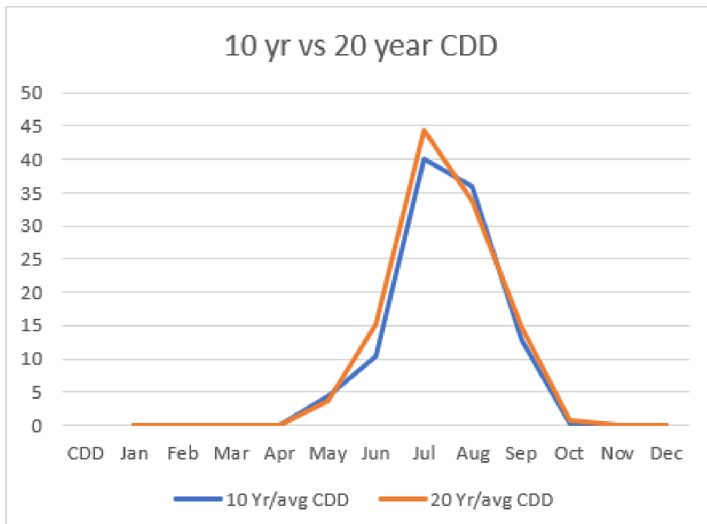
a) The following table compares the 10 and 20-year averages to results of applying the TREND function in Excel using the 1999-2018 actual data. API notes that 2018 HDD and CDD totals are relatively high compared to the average values, which distorts the 20-year trend. A similar trending exercise using a 19-year trend (1999-2017) yields noticeably different results, as shown in the table. Please see the graphs on the subsequent page for a comparison of 10-year to 20-year averages for HDD and CDD.

	Average		20-yr Trend		19-yr Trend	
	10 year	20 year	2019	2020	2019	2020
HDD						
Jan	873.3	856.0	851.4	851.0	849.3	848.7
Feb	775.2	765.7	802.1	805.5	809.3	813.3
Mar	690.6	691.8	717.0	719.4	711.3	713.3
Apr	464.6	442.6	493.8	498.7	470.0	473.2
May	237.7	240.6	244.8	245.2	252.3	253.2
Jun	105.5	99.4	107.5	108.2	108.0	108.8
Jul	39.9	37.0	39.5	39.8	44.4	45.0
Aug	41.7	41.4	36.9	36.4	40.0	39.8
Sep	128.5	127.3	121.3	120.8	118.1	117.3
Oct	322.4	325.5	309.3	307.8	293.3	290.6
Nov	485.4	487.3	502.8	504.3	477.6	477.3
Dec	722.1	721.3	721.2	721.2	729.7	730.3
Total	**4886.8**	**4835.9**	**4947.7**	**4958.3**	**4903.3**	**4910.7**
CDD						
Jan	0.0	0.0	0.0	0.0	0.0	0.0
Feb	0.0	0.0	0.0	0.0	0.0	0.0
Mar	0.0	0.0	0.0	0.0	0.0	0.0
Apr	0.0	0.0	0.0	0.0	0.0	0.0
May	4.5	3.5	4.9	5.0	4.6	4.7
Jun	10.5	15.4	6.7	5.9	4.4	3.4
Jul	40.0	44.7	34.1	33.1	28.1	26.6
Aug	36.0	33.7	35.6	35.8	33.2	33.2
Sep	12.9	14.7	14.9	14.9	13.0	12.9
Oct	0.3	0.8	0.4	0.4	0.5	0.5
Nov	0.0	0.0	0.0	0.0	0.0	0.0
Dec	0.0	0.0	0.0	0.0	0.0	0.0
	104.1	**112.9**	**96.6**	**95.1**	**83.8**	**81.4**

	10 Yr/avg HDD	20 Yr/avg HDD
Jan	873.3	856.8
Feb	775.2	766.1
Mar	690.6	691.8
Apr	464.6	443.7
May	237.7	240.5
Jun	105.5	99.7
Jul	39.9	37.1
Aug	41.7	41.4
Sep	128.5	127.4
Oct	322.4	325.4
Nov	485.4	487.2
Dec	722.1	721.3



	10 Yr/avg CDD	20 Yr/avg CDD
CDD		
Jan	0.0	0.0
Feb	0.0	0.0
Mar	0.0	0.0
Apr	0.0	0.0
May	4.5	3.6
Jun	10.5	15.1
Jul	40.0	44.4
Aug	36.0	33.9
Sep	12.9	14.6
Oct	0.3	0.8
Nov	0.0	0.0
Dec	0.0	0.0



b) Please refer to the response to 3-VECC-20 (a) and (b).

3-Staff-39

Ref: Exhibit 3 / s. 3.1.7 / p. 17
Load Forecasting Model / Tab Forecast

Preamble:

API states that the source of the data for the employment variable is Stats Canada.

Question:

Please provide the source and derivation as applicable of the forecasted employment for 2019 and 2020.

RESPONSE:

Please refer to the responses to 3-VECC-18(a) and 3-VECC-20(c)

3-Staff-40

Ref: Exhibit 3 / s. 3.2.1 / p. 36
Load Forecasting Model / Tab CDM Adjustment

Preamble:

API has adjusted the forecast by:

- A full year of 2018 CDM program delivery
- A half year of 2019 CDM program delivery
- A full year of 2020 CDM program delivery

Questions:

a) Please explain why a full year of 2018 CDM program delivery was used when half of the savings would already be reflected in 2018 actual results
b) Please explain why a half year of 2019 CDM program delivery was used when the full year of program delivery should be reflected in 2020.
c) Please explain why a full year of 2020 CDM program delivery was used when only half of the savings would be realized in 2020.
d) Given the recent revocation of the 2015-2020 Conservation First Framework, please explain whether the overall CDM target of 7,510,000 kWh appropriately reflects planned CDM savings of those projects that API is contractually obligated to complete under the former Conservation First Framework.
e) For all projected CDM savings from outstanding CDM programs in 2019 and 2020 for the 2020 test year, please provide supporting documentation (such as detailed CDM reports, revised CDM plan, or delivery agreements) to confirm the level of projected savings and associated projects under the former Conservation First Framework.
f) Please re-file all relevant tables and supporting documentation to show the changes and impact on the load forecast.
g) Please confirm the corresponding LRAMVA threshold requested for approval as part of the application, and proposed rate class breakdown of the LRAMVA threshold. Please update Appendix 2-I of the Chapter 2 Appendices based on the CDM adjustment data included in API's Load Forecast model.

RESPONSE:

a) Please see response to 3-VECC-22(d).

b) Please see response to 3-VECC-22(d).

c) Please see response to 3-VECC-22(d).

d) As noted at page 34 of Exhibit 3, API submitted a joint CDM plan with CNPI, which allows aggregation of the assigned energy savings targets and funding for the two LDCs. While API was originally assigned a target of 7,510,000 kWh, the most recent joint CDM plan filed by API and CNPI (filed in 2017) allocated 11,809,134 kWh to API. Based on 2017 verified savings, and forecasted 2018-2020 amounts from the joint plan, API had forecasted to achieve 13,032,997 kWh in persisting savings in 2020, prior to revocation of the 2015-2020 CFF.

Based on the IESO's most recent Participation and Cost Report for API, filed in response to part f) below, as of April 15, 2019, API has achieved 5,568,278 kWh in energy savings persisting to 2020 (see cell CV105 on the "LDC Progress" sheet of the April 2019 report).

In response to part e) below, API has also filed a listing of 8 projects where applications under the CFF were previously approved by the IESO, but the projects have not yet been completed. API forecasts further savings of 5,499,923 kWh when these projects are completed.

Based on the above, as of the date of filing these interrogatory responses, API expects to achieve total energy savings of 11,068,201 kWh.

e) The table on the following page has been populated with all outstanding approved projects in API's CDM project tracking system:

Application ID	Framework	Project Description	Status	Adjusted Savings Estimate	Forecasted Savings Year
159884	CFF	Equipment Efficiency Upgrade	Pre-Project Application Approved	5,397,745	2020
173940	CFF	Equipment Efficiency Upgrade	Pre-Project Application Approved	5,289	2019
191609	CFF	Equipment Efficiency Upgrade	Final Invoice Under Review	9,916	2019
201176	CFF	Equipment Efficiency Upgrade	Pre-Project Application Approved	5,838	2019
202166	CFF	Equipment Efficiency Upgrade	Pre-Project Application Approved	7,701	2019
206025	CFF	Equipment Efficiency Upgrade	Pre-Project Application Approved	17,882	2019
206461	CFF	Equipment Efficiency Upgrade	Pre-Project Application Approved	35,867	2019
206983	CFF	Equipment Efficiency Upgrade	Post-Project Submission Saved As Draft	19,685	2019

API notes that the estimated kWh savings of 5,397,745 kWh in the first row reflect a reduction of 50% from the original project application estimate of 10,795,489 kWh. API expects the verified savings from this project to be less than the amount estimated in the original CFF application, and therefore reduced the estimated savings in prior CDM plans. The savings estimates for the remaining projects are consistent with the CFF applications.

f) The following table summarizes the updates to 2020 persisting energy savings resulting from the use of the most recent IESO Participation and Cost Report and consideration of outstanding projects identified in part e) above.

	2020 Persisting Savings		**Data Source for Update**
	Application	**Revised**	
2015 CDM Programs	1,077,279	1,077,279	N/A
2016 CDM Programs	1,427,961	1,427,959	IESO P&C Report; LDC Progress; Cell CD105
2017 CDM Programs	2,232,142	2,256,726	IESO P&C Report; LDC Progress; Cell CG105
2018 CDM Programs	7,237,615	752,898	IESO P&C Report; LDC Progress; Cell CH105
2019 CDM Programs	509,000	155,593	IESO P&C Report; LDC Progress; Cell CU105 (53,415) + Total of 2019 outstanding from part e) above (102,178)
2020 CDM Programs	549,000	5,397,745	Outstanding 2020 project from part e) above
Total	13,032,997	11,068,201	

API has filed the most recent IESO Participation and Cost report in support of the above revisions as “API_IRR_Participation and Cost Report_201904.xlsx”. Also, the CDM Adjustment and CDM Allocation sheets of the revised load forecast model filed in conjunction with these interrogatory responses reflects the lower 2020 CDM persisting savings and adjusted weighting factors in response to parts a) to c) above. Updated versions of Tables 18-20 from Exhibit 3 are filed in response to part g).

g) Please see the following pages for an update to OEB Appendix 2-I, as well as the class-specific allocations of the CDM adjustments to the 2020 load forecast and the LRAMVA threshold.

Updated OEB Appendix 2-I (Table 18 from Exhibit 3)

2015-2020 CDM Programs							
6 Year (2015-2020) kWh Target:							
7,510,000							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
%							
2015 CDM Programs						9.75%	14.34%
2016 CDM Programs						12.93%	19.01%
2017 CDM Programs						20.21%	29.72%
2018 CDM Programs						6.82%	10.03%
2019 CDM Programs						1.41%	2.07%
2020 CDM Programs						48.88%	71.87%
Total in Year						**100.00%**	**147.05%**
kWh							
2015 CDM Programs	1,077,169.00	1,068,894.00	1,068,387.00	1,093,167.00	1,086,232.00	1,077,279.00	1,077,279.00
2016 CDM Programs		1,437,693.00	1,437,694.00	1,437,694.00	1,437,694.00	1,427,961.00	1,427,961.00
2017 CDM Programs			2,640,268.00	2,250,773.00	2,248,143.00	2,232,142.00	2,232,142.00
2018 CDM Programs				767,494.00	760,196.00	752,898.00	752,898.00
2019 CDM Programs					155,593.00	155,593.00	155,593.00
2020 CDM Programs						5,397,745.00	5,397,745.00
Total in Year	**1,077,169.00**	**2,506,587.00**	**5,146,349.00**	**5,549,128.00**	**5,687,858.00**	**11,043,618.00**	**7,510,000.00 (Target from above)**

Weight Factor for Inclusion in CDM Adjustment to 2020 Load Forecast										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	
Weight Factor for each year's CDM program impact on 2020 load forecast	**0**	**0**	**0**	**0**	**0**	**0**	**0.5**	**1**	**0.5**	Distributor can select "0", "0.5", or "1" from drop-down list

2011-2014 and 2015-2020 LRAMVA and CDM adjustment to Load Forecast										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total for 2020**
	kWh	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**	**kWh**
Amount used for CDM threshold for LRAMVA (2015) - Total	750,001.00	750,001.00	750,001.00							
Amount used for CDM threshold for LRAMVA (2020)							752,898.00	155,593.00	5,397,745.00	6,306,236.00
Manual Adjustment for 2020 Load Forecast (billed basis)							376,449.00	155,593.00	2,698,872.50	3,230,914.50

Updated Class Allocation of CDM adjustments to Load Forecast (Table 19 from Exhibit 3)

Weather Adjusted Load Forecast Results					2018+2019+2020	2018+2019+2020	Share of 2020 Adjustment	Allocated CDM Adjustment	2020 Adjusted Forecast
	Year	2019	2020		(kWh)	(kW)			
R1(i)	Cust/Conn	7,722	8,116						8,116
	kWh	81,107,233	85,077,075		429,444		16.90%	220,020	78,446,984
	kW		-				0.00%		
R1(ii)	Cust/Conn	956	997						997
	kWh	25,693,841	28,598,828		231,913		17.96%	118,817	25,484,758
	kW		-				0.00%		
R2	Cust/Conn	39	37						37
	kWh	106,925,689	97,993,281		5,581,978		64.37%	2,859,851	85,867,987
	kW	246,943	226,314			12,892	100.00%	6,605	196,648
Seasonal	Cust/Conn	3,018	2,960						2,960
	kWh	5,917,619	5,886,661		23,985		0.78%	12,288	5,439,365
	kW	0	-				0.00%		
Street Lights	Cust/Conn	1,072	1,128						1,078
	kWh	571,581	601,043		38,916		0.00%	19,938	595,435
	kW	1,589	1,670			108	0.00%	55	1,655
Total	**Cust/Conn**	**12,807**	**13,238**						**13,328**
	kWh	**220,215,963**	**218,156,888**		**6,306,236**	**13,000**		**3,230,915**	**214,925,974**
	kW	**248,532**	**227,984**					**6,660**	**221,324**

Updated Class Allocation of amount used for CDM threshold for LRAMVA (Table 20 from Exhibit 3)

Weather Adjusted Load Forecast Results					2018-2019-2020 Achieved + Contracted kWh	LRAM Allocation
	Year	**2019**	**2020**			
R1(i) Residential	Cust/Conn	7,722	8,116			
	kWh	75,387,475	79,805,566		429,444	429,444
	kW		-			
R1(ii) GS < 50 kW	Cust/Conn	956	997			
	kWh	23,881,888	26,928,875		231,913	231,913
	kW		-			
R2 GS>50 kW	Cust/Conn	39	37			
	kWh	99,385,190	91,043,719		5,581,978	5,581,978
	kW	229,529	210,264		12,892	12,892
Seasonal	Cust/Conn	3,018	2,960			
	kWh	5,500,303	5,502,049		23,985	23,985
	kW	0	-			
Street Lights	Cust/Conn	1,072	1,078			
	kWh	568,784	595,435		38,916	38,916
	kW	1,581	1,655		108	108
Total	**Cust/Conn**	**12,807**	**13,188**			
	kWh	**204,723,640**	**203,875,644**		**6,306,206**	**6,306,206**
	kW	**231,110**	**211,919**		**13,000**	**13,000**

3-Staff-41

Ref: Exhibit 3 / s. 3.2.2 / pp. 38-39
Load Forecasting Model / Tab CDM Allocation

Preamble:

API has made a CDM adjustment of 15,332 kW to the R2 rate class. This appears to be a total of:

2017 savings persisting to 2020:	1,716 kW
2018+2019+2020 savings:	13,616 kW
Total:	15,332 kW

The LRAMVA target includes 12,332 kW of savings for the R2 rate class.

Questions:

a) Please confirm OEB staff's calculation or provide a derivation of the 15,332 kW adjustment.
b) If 2017 savings were used in the CDM adjustment, please provide the rationale
c) Please provide a breakout of forecasted CDM program demand savings in 2018, 2019, and 2020.
d) Please explain why the CDM adjustment for 2020 is higher than the LRAMVA target when the LRAMVA target includes a full year of savings for all years, and the CDM adjustment typically includes only a half year of savings in the most recent historic year and test year.

RESPONSE:

a) Not confirmed. The formula in cell O15 in the "CDM Allocation" Tab of the load forecast model only adjusts the 2020 R2 rate class demand value by 13,616 kW. This calculation is confirmed below:

2020 R2 Demand Forecast Pre-Adjustment	226,314 kW
2020 R2 Demand Forecast CDM-Adjusted	212,698 kW
Difference	13,616 kW

b) 2017 savings were not used in the CDM adjustment for demand, as per part a) above. 2017 savings were inadvertently factored into the allocation of 2018-2020 energy savings, but did not affect the total amount of energy that was allocated. Please see the response to 3-VECC-22(f) for further description of this issue and confirmation that the 2017 values have been cleared in the revised load forecast model.

c) The tables provided in response to 3-Staff-40(g) provide a breakout of demand savings based on the energy savings allocated to each rate class and the kW/kWh ratios for the rate classes where demand is included in the load forecast (R2 and Street Light).

d) Based on corrections and adjustments made in response to various interrogatories, the 2020 CDM adjustment is now lower than the 2020 LRAMVA threshold in the revised load forecast model.

Exhibit 4

4-Staff-42

Ref: Exhibit 4 / Appendix 2-JA

Question:

API shows a budget of $96,558 for community relations. With the conclusion of the acquisition of DLI and the filing of its 2020 cost of service application, please provide a detailed explanation for this expense.

RESPONSE:

The community relations costs in Appendix 2-JA represent API's ongoing costs related to community relation and customer engagement activities and do not include any costs related to the DLI acquisition.

The customer engagement and community relation activities related to this expense are described in detail at pages 62 to 68 of Exhibit 1. An explanation for the variances from 2017 to 2018 and from 2018 to 2019 is provided at page 28 of Exhibit 4.

Going forward, API expects to include the customers acquired from DLI and the Township of Dubreuilville in its ongoing customer engagement and community relation activities without a material increase in cost.

4-Staff-43

Ref: Exhibit 4 / Appendix 2-JA

Preamble:

For the 2020 test year API's proposes an increase of $1.07million or 24.3% in Administrative and General operating expenses over the 2015 OEB-approved budget.

Question:

Please provide a breakdown and explain the increase in detail.

RESPONSE:

API has explained drivers of the increase in Administrative and General operating expenses in Appendix 2-JB of the Chapter 2 filing requirements. These have been reproduced below for ease of reference. For explanations of each of these drivers, please refer to Section 4.2.2 Cost Driver Analysis within the Application. Additionally, for the $267,000 referenced below, please refer to 4-Staff-49. The remaining increase of $0.05 million represents a 1.2% increase over the 2015 OEB-approved budget.

$'s	Cost Driver
4,430,491	2015 BA
	Adjustments:
258,000	Add: Vehicle Depreciation Credit
341,000	Add: Sault Ste Marie Building Rent
155,000	Add: Regulatory Expenses
267,000	Add: Shared Services Administrative Services From CNPI Distribution
5,451,491	2015 BA Adjusted for App 2-JB Cost Drivers
5,504,968	2020 Test
53,477	Variance 2020 Test vs 2015 BA Adjusted for App 2-JB Cost Drivers
1.2%	

4-Staff-44

Ref: Exhibit 4 / s. 4.3.2 / p. 37

Preamble:

API shows an increase of $165k in overhead lines and feeders expenses in the test year over 2018 actuals. API noted a combination of increased pole rental cost ($40k), right of way land fees ($47k) and increased overhead work in the Dubreuilville area.

Questions:

a) Please confirm that the remaining cost driver in the amount of $78k is due to overhead lines and feeders maintenance in the Dubreuilville area.
b) Provide a detailed explanation as to the ongoing work required on distribution system assets in Dubreuilville given the remediation of the Dubreuil Lumber Inc.'s distribution system assets as an interim operator.
c) Confirm that this cost driver was previously tracked in the Interim Licence Deferral Account and compare to actual costs in 2017, 2018 and 2019 year-to-date.

RESPONSE:

a) Approximately $53k of the remaining $78k is due to overhead lines and feeders maintenance in the Dubreuilville area.

b) Related to overhead lines and feeders, on an ongoing basis API is required to respond to outages, power quality concerns and emergency situations, inspect distribution assets in Dubreuilville in accordance with Appendix C of the DSC, and maintain equipment in accordance with manufacturer's recommendations and industry standards.

c) API did not track programs in the Interim Licence Deferral Account with the same breakdown as Appendix 2-JC. API is however able to provide the following 2017, 2018 and 2019 year-to-date actual costs tracked as "outage and emergency response" in the Interim Licence Deferral Account:

Deferral Account Cost Category	2017	2018	2019 to June 30
Outage and Emergency Response	$51,999	$52,363	$8,794

4-Staff-45

Ref: Exhibit 4 / s. 4.3.2 / pp. 8, 29 and 41
Appendix 2-JBExhibit 2 / DSP / pp. 149 - 151

Preamble:

API shows a cost driver of $341k in anticipated rent increase for its use of the in Sault Ste. Marie facility. API has also requested ACM treatment for a new facility with an in-service date of 2022. On page 29 of exhibit 4, API notes that it "will consider the impact of any reduction in 2023-24 facility operating cost when it submits its application for ACM cost recovery of the new facility".

Questions:

a) Confirm that both requests are driven by the expiry of the existing lease at 2 Sackville Rd. in Sault Ste. Marie.
b) Has API signed the new lease for the 2 Sackville Rd. facility? If not, please provide a status update.
c) Has API received any quotes for an alternate location?
d) Please explain how API is proposing to consider any reductions in facility operating costs during the IRM term? Is API's proposal to recalculate its revenue requirement for the 2022 rate year by adjusting both capital expenditures and operational expenditures?

RESPONSE:

a) Yes.

b) API has not signed a new lease. API is currently in discussion with Hydro One regarding a short term sublease (i.e. the term would align with API's move to its proposed the new facility) consistent with the terms of the head lease. Hydro One is currently negotiating a short term lease (head lease) with Brookfield. All parties are targeting a new short term lease to be finalized before the expiry of the current lease.

c) API has not received quotes as no suitable sites to lease have been found. API conducted a search of possible available sites in Sault Ste Marie, with the help of a consultant and real estate representative. Nine (9) potential sites were identified, and subsequently investigated and it was determined that none of the sites would meet the requirement of API's operations.

d) API proposes that any anticipated reductions in facility operating costs during the IRM term be included as an offset to the incremental revenue requirement calculated by the OEB's ACM model.

4-Staff-46

Ref: Exhibit 4 / s. 4.2.2 / p.29

Question:

API is proposing to dispose of its account balance of $551k in the transaction and integration deferral account through a one-time regulatory costs (amortized over 5 years). Please provide a rate rider calculation and a bill impact that would result from a traditional disposition of a deferral account through a rate rider versus this alternate funding approach.

RESPONSE:

In API's view, the rate rider could only apply to the former DLI customers, since applying it to API's broader customer base would effectively cause those customers to be harmed by the MAAD transaction.

The balance that API is proposing to recover through a one-time regulatory cost amortized over 5 years has been revised to $617,765. API further notes that the forecast of $551k should actually have been $596k, due to a formula error. Both of these adjustments are detailed in response to 4-Staff-57.

Recovering $617,765 from the former DLI customers through a rate rider, using the same approach that was used to derive the $11.16 per customer per month rate rider in the MAAD application (EB-2018-0271), results in the following rate rider:

Reference	Description	Value
A	Revenue Required	$617,765
B	Customer Count	357
C	Disposition Period	6 Years
D = A / (Bx12xC)	Required Rate Rider	$24.03

Implementing the above rate rider on January 1, 2020 would result in the total bill for a typical residential customer in Dubreuilville (750 kWh, RPP) increasing from $129.30 to $158.01, or 22.2%. This increase would be in addition to the approximately 15% bill impact experienced in August 2019 when API's rates and the $11.16 rate rider came into effect. In API's view, this is clearly not an appropriate approach.

4-Staff-47 Shared Services

Ref: Exhibit 4 / s. 4.5 / p. 57

Questions:

a) Please provide the corporate cost allocation study by BDR, included in CNPI's last rebasing application.
b) Describe any changes that were made to API's corporate cost allocation methodology as a result.

RESPONSE:

a) The requested report has been filed as "API_IRR_4-Staff-47 BDR Report.pdf".

b) See table below for shared services allocation percentages that changed from the 2015 and 2016 period, to the 2017 to 2020 period. The changes reflected a slight increased FTE effort to API Distribution in the areas of HSE, IT and HR and are reflected in the values submitted in Appendix 2-N of the Chapter 2 appendices.

Shared Service Allocations			
Shared Service	**2015 to 2016**	**2017 to 2020**	**Change**
HSE	33.6%	36.9%	3.3%
IT	33.5%	34.8%	1.3%
HR	29.8%	36.9%	7.1%

4-Staff-48

Ref: Exhibit 4 / Appendix 4C

Preamble:

The above reference is the services agreement between CNPI and its affiliates dated September 15, 2015.

Question:

Please confirm that the service agreement dated September 15, 2015 is the most recent agreement and state whether API's current rates were based on that agreement. . If not, were any significant changes made in the current services agreement from the agreement used in its last cost of service application. If so, what are they and how have they impacted costs allocated to API for shared service/corporate cost allocation?

RESPONSE:

Confirmed that the service agreement dated September 15, 2015 is the most recent agreement. In API's 2015 cost of service application, the service agreement dated September 15, 2010 had been the agreement in place. There were no significant changes made between the agreement dated September 15, 2010 and September 15, 2015.

4-Staff-49 Corporate Cost allocation

Ref: Exhibit 4 / s. 4.5
Appendix 2-N

Questions:

a) Please provide a detailed organizational chart for CNPI and Fortis Ontario and provide the corporate costs that are allocated to API and each of its affiliates at the executive level as well as at the departmental level.
b) Provide a breakdown of all corporate services provided by Fortis Ontario, including the cost for each service, a description of the corporate cost allocation methodology and the allocated percentage for each service for the test, bridge and the 2018, 2017, 2016 and 2015 actuals.
c) Provide a breakdown of all administrative services provided by CNPI Distribution, including the cost for each service, a description of the corporate cost allocation methodology and the percentage allocated to API for each service for the test, bridge and the 2018, 2017, 2016 and 2015 actuals.
d) Please explain any variances or the absence of variances.

RESPONSE:

a) Please refer to the Utility Organizational Structure provided on page 35 in Section 1.3.17 of Exhibit 1. The first two levels of the chart (i.e. President and Vice Presidents) along with the Legal unit represents FortisOntario, while the remainder of the structure would be equally applicable for both CNPI and API as both corporate and subsidiary specific units have been identified. The corporate costs, including the executive costs, that have been allocated to API have been provided in Appendix 2-N of the Chapter 2 appendices filed with the Application.

b) Executive services are provided by FortisOntario. Both the percentages and the amounts have been provided in Appendix 2-N of the Chapter 2 appendices filed with the Application. The allocation methodology can be found in the BDR report provided in 4-Staff-47.

c) Administrative services provided by CNPI Distribution to API in Appendix 2-N of the Chapter 2 appendices filed with the Application include: finance, information technology, human resources, health, safety and environmental, and regulatory. The allocation methodology can be found in the BDR report provided in 4-Staff-47. The cost and allocated percentage allocated to API for the various administrative services provided by CNPI Distribution to API are as follows:

	2015		2016		2017		2018		2019 Bridge		2020 Test	
	$ Allocated	% Allocated	$ Allocated	% Allocated	$ Allocated	% Allocated	$ Allocated	% Allocated	$ Allocated	% Allocated	$ Allocated	% Allocated
Regulatory	62,938	18.8%	57,062	18.8%	58,849	18.8%	36,968	18.8%	30,526	18.8%	51,544	18.8%
Finance	559,364	36.4%	580,266	36.4%	598,129	36.4%	479,771	36.4%	616,082	36.4%	630,382	36.4%
HSE	176,244	33.6%	180,721	33.6%	213,811	36.9%	228,625	36.9%	243,511	36.9%	267,285	36.9%
IT	505,091	33.5%	482,827	33.5%	504,495	34.8%	440,164	34.8%	572,415	34.8%	585,702	34.8%
HR	123,124	29.8%	97,750	29.8%	139,786	36.9%	115,664	36.9%	132,278	36.9%	130,420	36.9%
Total Shared Services from CNPI Distribution	**1,426,761**		**1,398,626**		**1,515,070**		**1,301,192**		**1,594,811**		**1,665,334**	

d) There were no material variances in executive services provided by FortisOntario to API, from 2015 Actual to 2020 Test. Material variances in the administrative services provided by CNPI Distribution to API are described in Section 4.5 Shared Services & Corporate Cost Allocation of Exhibit 4 of this Application.

4-Staff-50

Ref: Exhibit 4 / s. 4.5 / p. 58

Preamble:

At page 58 of the above reference, API states that:

> Fortis Inc., FortisOntario's parent company, charges FortisOntario, and other Fortis-owned companies, for strategic planning, finance and administrative services such as costs incurred related to the listing of Fortis shares on the Toronto Stock Exchange and charges related to the administration of share purchase plans, and other costs. Consumers benefit from these services by providing CNPI with access to capital, which provides the required capital investment in the CNPI distribution system for a reliable and safe supply of electricity. The charges are allocated to FortisOntario. The charges allocated to FortisOntario are subsequently charged to the five business units within FortisOntario based on assets and share purchase plan participants. Cost-based pricing is used for the charges.

Questions:

a) Please state whether there are any shared capital assets between the transmission and distribution systems and if so, what assets these would be and how the costs of such assets would be allocated between transmission and distribution.
b) Please state whether or not there are any allocations between the business units other than those described in the above paragraph and if so how they are undertaken.
c) Please elaborate on how charges would be allocated "based on assets and share purchase plan participants" as referenced in the above quotation.
d) Please elaborate on what is meant by "cost-based pricing" in the above paragraph and how it is determined.

RESPONSE:

In reviewing the preamble referenced for this question, API was unable to locate this exact verbiage within the Application submitted. API noted the following paragraph that was submitted as part of this Application:

Fortis Inc., FortisOntario's parent company, allocates to the FortisOntario group, and other Fortis-owned companies, costs for strategic planning, finance and administrative services such as costs incurred related to the listing of Fortis shares on the Toronto Stock Exchange and New York Stock Exchange, and charges related to the administration of share purchase plans, and other costs. Consumers benefit from these services by providing API with access to capital, which provides the required capital investment in the API distribution system for a reliable and safe supply of electricity. The charges are allocated to FortisOntario. The charges allocated to FortisOntario are *subsequently charged to the five business units within FortisOntario based on relative rate base and relative revenues. Cost-based pricing is used for the charges.*

a) API does not own transmission assets. Therefore, all assets reported in this Application are distribution related.

b) There are not any allocations between the business units other than those described in the above paragraph.

c) Please refer to paragraph submitted above which was included in the Application. The costs are allocated based on relative rate base and relative revenues.

d) Fortis Inc. charges FortisOntario its allocated costs outlined in the paragraph referenced above without mark-up, and FortisOntario then charges five business units without mark-up; therefore cost-based pricing is used.

4-Staff-51 Shared IT Services

Ref: Exhibit 4 / s. 4.3.2 / pp. 57-63
Exhibit 2 / DSP / p. 87 / Table 4-4

Preamble:

On page 63, API notes that the increase of $560,455 in the 2020 test year over 2015 OEB-approved costs for administrative services received from CNPI Distribution is due to an increase in IT shared assets. On page 62 API states that an increase of $246,400 in administrative services in the 2020 test year over 2015 OEB-approved is also due to additional IT service costs.

Questions:

a) Please provide further detail as to the nature of these costs and confirm that they are distinct and incremental.
b) Please explain why 35% of shared IT cost are allocated to API versus 25% of administrative services.
c) Is any of the $227k budget for IT hardware, shown in table 4-4 of the DSP, related to either allocate IT costs or requirements under the Ontario Cyber Security Framework?

RESPONSE:

a) The $560,455 relates to IT shared assets referred to as shared IT from CNPI Distribution to API in the Appendix 2-N of the Chapter 2 filing requirements. Further explanation of this amount and how it was derived can be found in *"Allocation of Shared Assets"* on page 58 of Exhibit 4.

The additional IT service costs, one of the contributing factors to explain the increase of $246,400 in the administrative services from CNPI Distribution to API, relates to API's share of the operational costs of information technology. API notes that there were multiple contributors to the $246,400, as highlighted on page 62 and 63 of Exhibit 4.

The two above are distinct. For greater clarity, the $560,455 is not incremental relative to API's 2015 cost of service application; rather it is a change in approach with respect to the allocation of the shared IT assets from CNPI distribution in accordance with Board preference. As outlined in Exhibit 2 (page 10 to 11 of 57), in the 2015 API cost of service application, API had added it's share of the IT capital assets to net assets for 2015, which in turn was then reflected in API's rate base calculation. In this proceeding, API has not included this allocation in its rate base calculation for 2015 Actual to 2020 Test; rather the shared IT cost has been reflected in OEB 4380. See Section 3.4.2 of Exhibit 3 for additional variance explanation provided for OEB 4380, as well as additional shared service variance explanations in Section 4.5 of Exhibit 4.

b) Please refer to 4-Staff-47. Similar to the IT shared assets, 35% of the administrative services related to information technology are allocated to API.

c) The $227,000 does not relate to either of the allocated IT costs, or the requirements under the Ontario Cyber Security Framework.

4-Staff-52

**Ref: Exhibit 4 / s. 4.3.2 / pp. 8 and 62-63
Appendix 2-N**

Preamble:

API has proposed an increase in shared services of $364k over 2015 OEB-approved amounts in 2020. API notes that the increase reflects the charge allocated to API for IT service costs related to a Managed Security Service Provider (MSSP) agreement. API further notes that the IT costs, allocated to a Managed Security Service Provider agreement address requirements of the OEB Cybersecurity Framework.

Questions:

a) Please specify API's share of the corporate cost attributed to enhancing cyber security measures as per the Ontario Cyber Security Framework.
b) Please specify the corporate cost allocated for the MSSP that was allocated to API.
c) Does API and/or its affiliates conduct annual risk reviews? If so, are these costs included in corporate costs allocated to API?
d) Are the requested cyber security expenditures mapped to a specific risk area or gap identified in a cyber-risk audit/security risk assessment and does the proposed spending address this gap? If so, please explain how in general terms.
e) Which range of technology services are being provided as part of this allocation.
f) Please provide the type of training provided to staff each year for cyber security and highlight the corporate cost allocation for staff.
g) Is the cyber security infrastructure on-site or cloud based?
h) Is this material summarized and reported to its Board of Directors and approved to address identified cyber security risks?

RESPONSE:

According to Appendix 2-N of the referenced material for this question, API would like to clarify that it is proposing an increase of $246k over 2015 OEB-approved amounts in 2020, not the $364k noted in the preamble above.

a) API estimates that API's share of corporate cost attributed to enhancing cybersecurity measures as per the Ontario Cyber Security Framework will be approximately $115,000 which includes the MSSP costs, additional third party ongoing assessment costs, and a refocus of internal staff on managing cyber security requirements on an ongoing basis.

b) $61,000 was allocated to API.

c) Yes, risk reviews/assessments are included in the $115,000 estimated included in part a) above.

d) The MSSP will help to directly address two deficient practices that were identified in a cybersecurity maturity assessment performed by a third party. These practices related to the absence of 24x7x365 monitoring and event response for corporate and operational technology networks and assets.

e) The MSSP provides uninterrupted security monitoring and threat detection on corporate (IT) and operational (OT) networks across FortisOntario, including Algoma Power. Some additional on-going third party along with additional internal staff resourcing will be to utilized to enhance software such as multifactor authentication, password management, and software patching tools used across the organization.

f) Formal cybersecurity training & testing is delivered to staff via a platform called KnowBe4, which allows for the ability to conduct phishing click testing, cyber awareness training/testing, and other programs. These are at various stages of implementation. Outside the use of the KnowBe4 platform, given that the training effort is largely internal, API's allocation of these costs would be approximately $5,000. This amount is in the $115,000 noted in a) above.

g) The cybersecurity framework is a combination of on premise for firewalls, antivirus, email threat detection, and password management, and the MSSP/security monitoring is cloud based.

h) Yes, the Board is updated on the status of cybersecurity initiatives, any incidents/events that may have occurred, and would also be updated in the event of any major risks/threats API feels are necessary to report.

4-Staff-53

Ref: Exhibit 4 / pp. 14 and 38
Exhibit 2/ DSP / Appendix A
Exhibit 1/ Appendix 1A – Business Plan / pp. 6-7

Preamble:
API shows an increase of 8.2% or $270k in the 2020 test year over 2015 OEB-approved in its Right of Way ROW) Maintenance program. This represents a 1.6% compounded annual growth rate. On page 38, API notes that that a key contractor in the region is no longer available.

API shows the annual workload as follows:

VM Cycles and Annual Workload				
Work Category	Brush Removal	Herbicide Application	Tree Trimming	Hazard Tree Removal
Cycles (Year)	9	3	6	3
Annual Workload	120.4 ha	101.6 ha	7.87 ha	1293 trees

Questions:

a) How does API plan to fulfill the above shown vegetation management program following the departure of a key contractor in the area.
b) API noted that as of late 2017, it identified additional providers for its vegetation management program. Please provide the outcome of its competitive procurement process.
c) Provide the unit cost identified through the request for proposal and compare to historic unit cost.
d) Compare 3rd party costs against internal labour costs.

RESPONSE:

a) To account for the departure of a key contractor in the area and a provincial wide utility arborist (UA) resource shortage, API has modified its current Vegetation Management Plan (VMP) by reducing the number of kms requiring vegetation management to be completed by a UA. API has taken steps to look for new resources in and outside of the province, review work methods to gain more effective and efficient practices (including increased use of mechanical equipment and herbicide treatment) and potentially implement changes to cycle frequency based on the consultant's recommendations.

b) API has secured resources required to complete its VMP through the success of its most recent tender but at a higher cost compared to API's historical unit costs. API has structured its 2019-2020 VMP to gain a better understanding of the competitive market including the permanency of the identified increase in cost. With the release of less kms to accommodate for the higher costs, API will not complete approximately 25 kms of the 2019 program. There is concern that a continual reduction in kms to be completed will have a significant impact on API's VMP objectives as the current program is based on growth rates, tree mortality and a just in time approach to effectively manage actual work volume.

c) Below are the unit costs identified through the bid submissions compared to API's estimated unit cost for 2019 and historical unit costs.

Density L = Light M = Medium H = Heavy	**Scope of Work** L/C = Line Clearing B/C = Brush Control	**Part / Location**	**# of kms**	**2019 Average Bid Price**	**2019 Estimated cost / km**	**Historical cost / km**
L-M	L/C, B/C	Batchawana Part 1	13	$42,322.54	$15,000.00	$16,584.00
L-M	L/C, B/C	Batchawana Part 2	11	$63,586.17	$15,000.00	$19,540.75
H	L/C, B/C	Goulais Part 4	48.6	$29,402.71	$18,000.00	$19,000.00
L	L/C, B/C	Bar River Part 1	36	$16,528.78	$13,500.00	$16,470.00
M	L/C, B/C	Bruce Mines Part 1	40	$18,276.95	$16,372.06	$16,372.06
M	L/C, B/C	Bruce Mines Part 4	78	$19,626.23	$16,000.00	$16,000.00
L-M	L/C, B/C	St. Joe's Island Part 4	62	$21,010.85	$15,000.00	$17,000.00

d) API's internal labour force is a specialized crew designed to manage UA based work including regular maintenance activities, unplanned (storm) and demand work (customer sensitivity driven / new construction). The internal crew is readily accessible to respond when required and provides a specific skill set designated to perform hold offs and switching & grounding operations. API's internal crew is sized appropriately for the volume and type of work required to complete API's planned and unplanned work. Contracted services complete large areas of API's annual VMP. Larger crews are equipped to handle bulk work and have access to mechanized equipment often used in vegetation management to achieve effective control and provide efficiencies to meet production driven goals. Comparatively, when looking at a typical removal crew, contracted service crews commonly have a UA and a utility arborist apprentice (UAA) to manage UA based work whereas API's fulltime internal crew are UAs and can also provide the higher designate skill set for operating the system.

The chart below summarizes the UA based work for internal labour costs and 3rd party costs for a typical 3 person removal crew.

Contractor A							
Crew	UA	UAA	Labourer	Forestry Lift	Chipper	Subtotal	**Crew cost/month**
Removal	63.78	55.75	51.30	47.31	12.86	231.00	**36,959.90**
Contractor B							
Crew	UA	UAA	Labourer	Forestry Lift	Chipper	Subtotal	**Crew cost/month**
Removal	56.30	39.65	33.43	29.35	7.00	165.73	**26,516.80**
Contractor C							
Crew	UA	UAA	Labourer	Forestry Lift	Chipper	Subtotal	**Crew cost/month**
Removal	68.25	55.10	44.75	48.55	31.25	247.90	**39,664.00**
API Rates*							
Crew	UA Designate	UA	Labourer	Forestry Lift	Chipper	Subtotal	**Crew cost/month**
Removal	80.00	80.00	80.00	Incl.	Incl.	240.00	**38,400.00**

*** Note: API Rates are fully-burdened including work equipment.**

4-Staff-54 Distribution Transformers

Ref: Exhibit 4 / s. 4.3.1 / p. 34 - Appendix 2-JC

Preamble:

API has requested a maintenance budget of $17,446 for Distribution Transformers. Over the 2015 to 2019 period, API spend an average of $9,738 in this category due to underspending in 2017 and 2018.

Question:

a) Please explain the low levels of expenditures in 2017 and 2018.
b) Provide the year-to-date expenditure on distribution transformers and provide an explanation as to how API intends to achieve the forecasted budget.

RESPONSE:

a) This category of costs relates primarily to reactive requirements as opposed to planned maintenance. Activities include retiring obsolete transformers or changing transformer taps to resolve voltage concerns. In 2017 and 2018, API had fewer requirements of this nature.

b) 2019 year-to-date spending in this category is $0. The forecasted budget is based on allocating a small portion of the available line crew labour hours to this category during the annual budgeting process. Actual costs will be based on API's need to remove obsolete transformers, adjust transformer taps, or otherwise operate or maintain transformers. To the extent that this reactive work is not required, the budgeted line crew labour hours would be reallocated to other planned maintenance activities.

4-Staff-55 Regulatory Costs

Ref: Exhibit 4 / s. 4.6.3 / pp. 70 – 71

Question:

Table 14 on page 71 shows intervenor cost of $130,000 ($32,500 x 4). Please revise the regulatory costs to match the intervention requests in this application.

RESPONSE:

API notes that this amount includes intervenor and OEB costs. Accordingly, API has reduced the regulatory costs to $97,500, to account for 2 intervenors, plus OEB costs. Since these costs are amortized over a five-year period (2020-2024), API has reflected a reduction of $6,500 ($32,500 / 5) in the revised RRWF filed in response to 1-Staff-2.

4-Staff-56 Compensation

Ref: Exhibit 4 / s. 4.4.1 / pp. 42-47

Preamble:
On page 47 API noted that its compensation, overtime and benefits for unionized employees is set out in a collective agreement what will expire on December 31, 2019.

Questions:

a) Please state what assumptions regarding wage increases and benefits were made for the 2020 – 2024 budget and state whether API has started negotiations to reach a new collective agreement.
b) Please state whether or not API has a compensation strategy document, if so please file it. If not, state whether or not the information contained at the above reference is the extent of API's compensation strategy or, if this is not, provide the additional information.
c) If not discussed in the response to part b, please state how compensation has been aligned to performance expectations for management and other employees.

RESPONSE:

a) An increase estimate of 2.5% was assumed for the 2020 Test Year for wage and benefit increases. The increase also includes step increases for employees. Similar increases are assumed through the 2024 period. Exhibit 4-A, is in support of this assumption. As of IR submission date, negotiations to reach a new collective agreement have not yet commenced.

b) API does not have a compensation strategy document. However, API recognizes the importance of cost prudence and the expectations of its customers and the OEB. The IRM framework provides adequate guidance for API in developing its compensation strategy.

c) As outlined in Exhibit 4, section 4.4.1 p. 42-43, actual salaries are set by referencing a policy line recommended by Korn Ferry management consultants and are based on corporate and individual performance. The short-term incentive ("STI") is available to the Executive, Management and Non-Union staff of API, and reflect an element of compensation put at risk to elicit and sustain continued good performance. The STI plan is comprised of both an individual and a corporate component. Individual targets are developed in consultation with individuals and their immediate supervisors/managers and are reflective of key projects or goals and focuses on departmental or divisional priorities.

Corporate targets have three performance levels and are reflective of key corporate targets or goals.

4-Staff-57

Ref: Exhibit 1, pp. 20-21
Exhibit 4, p. 69
EB-2018-0271 Application, September 24, 2018, Exhibits F-3-1 and F-3-2
EB-2018-0271 Decision and Order, April 4, 2019
EB-2018-0271 Final Rate Order, June xx, 2019

Preamble:

In Exhibit 1, API has proposed to dispose of the estimated balance of the Interim Licence Deferral Account (ILDA) and the Transaction and Integration Costs Deferral Account (TICDA) balances in a manner in which it treats recovery of 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 are referred to.

API further states:

> 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.

In Exhibit F-3-2 of the EB-2018-0271 application, API provided the following table of the actual and forecasted balance up to December 31, 2019 for the ILDA and what was to be transferred to the proposed TICDA:

Description	2017 Actual	2018 Forecast	2019 Forecast	Total
Transaction Costs	-	83,674	85,000	168,674
Transfer of One-Time Costs from Deferral Account	133,617	71,307	97,453	302,377
Transfer of 50% of 2017 OM&A from Deferral Account	80,447			80,447
Total Transaction and Integration Costs	214,064	154,981	182,453	551,499

The OEB issued its Decision and Order for EB-2018-0271 on April 4, 2019, and the Final Rate Order on June 13, 2019. The Decision and Order and the Final Rate Order established the amounts to be tracked in each of the ILDA and the TICDA, as well as approving on an interim basis certain costs t that are being tracked in the ILDA. In particular, costs prior to September 24, 2018, the date of filing of the EB-2018-0271 application, are tracked in the ILDA, while costs from September 24, 2018 onwards are recorded in the TICDA.

Questions:

a) Please confirm that, for the most part, costs in the ILDA and TICDA were not reviewed with respect to need and prudence as part of the EB-2018-0271 proceeding.

b) Please provide a detailed breakout of the costs being recorded in each of the ILDA and TICDA as to the nature, time period, whether the costs are audited actuals, unaudited actuals, or forecasts, and whether the costs are part of what was approved by the OEB in the Decision and Order and the Final Rate Order in EB-2018-0271. This breakout of costs should be provided in tabular format, and should reflect any current estimates of costs to December 31, 2019. If possible, please provide the table in working Microsoft Excel format.
c) Please confirm that API is seeking that costs in the ILDA that were not approved by the OEB in its Decision and Order and Final Rate Order in EB-2018-0271 be reviewed for need and prudence as part of the current application in order to seek disposition as proposed by API.
d) Please provide any necessary explanation and support for the actual and forecasted costs being tracked in the ILDA and the TICDA to enable the OEB to assess the need and prudence.
e) 2019 costs will not be actuals at this point, and may not be actuals or audited actuals, at the time of the OEB's decision or rate order in this proceeding. Most of the time, when DVA account balances are disposed, they are based on audited actuals, although exceptions have been allowed.
API has proposed disposition of the ILDA and TICDA balances to December 31, 2019 by amortizing the total amount over five years.
    i. Is API proposing that the ILDA and TICDA balances be approved on a final basis for recovery under this proposal? If so, please provide API's views on how this is consistent with OEB policies and practice of DVA balance disposition and recovery.
    ii. In the alternative, please explain how any adjustments, such as for audited actual December 31, 2019 amounts, would be incorporated into the amounts being recovered through an adjustment to the revenue requirement for each year from 2020 to 2024. For example, is API proposing that the amounts to be disposed in 2021 to 2024 be adjusted to reflect year-end 2019 audited actuals from the $551,499 currently being proposed?
    iii. DVA balances proposed for disposition and recovered through rate riders are not subject to the (inflation less productivity) Price Cap IR adjustment. Is API proposing that the adjustment for 1/5 of the ILDA and TICDA balance be done to API's revenue requirement before or after the application of the annual price cap adjustment? If before, please explain the reason for this proposal and how this is consistent with the OEB's policy for disposition and recovery of DVA balances.

RESPONSE:

Preamble: API wishes to clarify certain aspects of the preamble to the questions presented above:

First, the preamble incorrectly suggests that the table provided in Exhibit F-3-2 of EB-2018-0271 provides the forecasted balance of the ILDA and what was proposed to be transferred to the TICDA. The table in the preamble only reflects the forecasted TICDA balance, based on a forecast of transaction costs, plus amounts that API proposed to transfer from the ILDA to the TICDA. It does not include the significant residual amounts in the ILDA. The table from Exhibit F-3-2 of EB-2018-0271 needs to be considered in conjunction with the table from Exhibit F-3-1 of the same application, which contains the forecasted ILDA balance (prior to any proposed transfers to the TICDA), which OEB Staff reproduced in the Preamble to 9-Staff-77.

Second, the preamble indicates that the Decision and Order and Final Rate Order in EB-2018-0271 require that costs incurred prior to September 24, 2018 are recorded in the ILDA and costs incurred from September 24, 2018 onward are recorded in the TICDA. On page 1 of its Final Rate Order in EB-2018-0271, the OEB determined that:

> "There is no reason for balances to be transferred from the Interim Licence Deferral Account (ILDA), established while Algoma was the interim operator of Dubreuil's distribution system, to the Transition and Integration Costs Deferral Account (TICDA). The ILDA shall continue to exist, until the final determination on disposition of the balance. The purpose of the TICDA is to record only transaction and integration costs incurred from September 24, 2018 onwards."

As such, the ILDA contains all costs incurred prior to September 24, 2018, as well as all non-transaction costs incurred on or after that date. The TICDA contains only transaction and integration costs incurred from September 24, 2018 onwards.

API provides the following responses on the basis of the above clarifications:

a) Not confirmed. On page 4 of the Final Rate Order, the OEB explicitly found $383k in non-capital and one-time costs to be reasonable, and therefore recoverable by API.

   Further, on page 5 of the Final Rate Order, the OEB confirmed that as part of API's rate mitigation plan, only return of and return on capital costs for the 2017-2019 period were being recovered through the interim rate rider approved in EB-2018-0271, with the undepreciated capital cost to form part of API's 2020 rate base. The OEB explicitly approved this rate mitigation plan on both page 1 and page 5 of the Final Rate Order.

   The only cost that was therefore not reviewed for need and prudence was approximately $71k in transaction costs that were incurred prior to September 24, 2018 (recorded in the ILDA). The OEB's findings with respect to those costs, from page 4 of the Final Rate Order are as follows:

> *"Algoma is relying on the presence of the ILDA to make the argument that recovery of the $71K is prudent, and the panel for the EB-2019-0019 rates proceeding can make that determination. There was insufficient evidence on the record on the timing and nature of the transaction and integration costs to make a final determination on the prudence of the costs in this proceeding."*

Notwithstanding the above, the breakout of costs recorded in the ILDA and TICDA provided in response to part b) below details describes the need for all cost recorded in these accounts.

b) As requested, API has provided an analysis of costs in working Microsoft Excel format. Please see "API_IRR_4-Staff-57_DLI Costs.xlsx". Description of each cost category is provided below:

- OM&A costs are broken out by significant program, including outage and emergency response, meter reading, customer service, billing and collections, supervisory and administrative support, and cyclical maintenance. All of these costs are inherently a normal part of operating the distribution system and are being recovered through the interim rate rider approved in EB-2018-0271, with the exception noted below in relation to 50% of 2017 costs.
- Cost of power and billed revenue tracking captures both the costs billed to the legacy DLI R2 account and the revenues collected from individual accounts in the Township of Dubreuilville, as directed in the OEB's initial decision and order appointing API as the interim operator of DLI's distribution system. The result is that the net credit balance (i.e. 2017-2019 revenue from individual customers exceeds costs billed to the legacy DLI R2 account) acts as an offset to the portion of costs recorded in the ILDA that are being recovered through the interim rate rider approved in EB-2018-0271, with the exception noted below in relation to 50% of 2017 costs.
- API included only 50% of the 2017 total of OM&A, Cost of Power and Billed Revenue amounts in the model that underpinned the interim rate rider in EB-2018-0271. The rational put forward in EB-2018-0271 was that a portion of the 2017 amounts in these categories related to either initial compliance with the OEB's initial decision and order appointing API as the interim operator of DLI's distribution

system and/or a one-time transition and ramp-up of OM&A and billing related activities. API therefore proposed to recover the other 50% of 2017 costs through its 2020 revenue requirement (amortized over five years), consistent with other cost specifically identified in the one-time and transaction cost categories.

- Capital costs relate primarily to line capital (which includes a new bypass line to decommission Substation #1 as well as condition-based pole and equipment replacements), metering replacements (required for Measurement Canada compliance and compliance with various OEB codes), and an immaterial amount in the substation and underground category relating to the replacement of a leaking pad-mounted transformer installation.
- One-time costs include a variety of costs necessary to comply with OEB direction to assess the condition of DLI's distribution, provide status reports, work towards regulatory compliance, and resolve any priority issues. The cost categories listed in the above-referenced spreadsheet are self-explanatory.
- Transaction costs of approximately $71k incurred prior to September 24, 2018 relate to the negotiation and development of an Asset Purchase Agreement (approximately $35k in external legal costs to March 2018), related due diligence and legal matters such as real estate transactions, and legal costs related to the preparation of the MAAD application (approximately $36 in external legal costs from May to September 2018). Costs incurred subsequent to September 24, 2018 include legal costs related to procedural aspects of the MAAD application, and legal costs associated with remaining transactional requirements to close the commercial transaction.

c) Please see the response to a) above. It is API's position that the only costs that the OEB did not address in EB-2018-0271 are the approximately $71k in transaction costs incurred prior to September 24, 2018, which are detailed in response to part b). Notwithstanding this position, all other costs recorded in the ILDA and the TICDA are also detailed in the response to part b).

d) Please see response to parts a) through c).

e) For clarity, API has requested disposition of the full balance of the TICDA, but only a portion of the balance in the ILDA, as explained in the above preamble, and as calculated in the spreadsheet accompanying this response. The total requested for recovery through One-Time costs has been updated to $617,765, amortized over five years.

i. API is proposing that disposition of the TICDA be approved on a final basis. Approximately $150k of the $170k total costs have already been incurred and API expects to receive all final invoices from external counsel prior to the Draft Rate Order stage of the proceeding. API would update the total amount included in One-Time costs related to the TICDA at the Draft Rate Order stage (or earlier) based on these final invoices. Due to the nature of the costs involved (legal fees supported by invoices), API believes that adjustments related to these costs during its 2019 year-end audit are extremely unlikely.

   With respect the portion of the ILDA balance proposed to be recovered through One-Time costs, API notes that a credit would be applied to the ILDA account, but that the ILDA account itself would remain active, in accordance with the OEB's Final Rate Order in EB-2018-0271. Any variance between forecast and actual would therefore be captured in the ILDA, and would be considered in the final disposition of that account. This would allow the OEB to adjust the interim rate rider approved in EB-2018-0271 and approve disposition on a final basis based on updates for audited actuals in a future API IRM application.

ii. See response to part i).

iii. DVA balances approved for disposition are often approved for recovery over a short period of time (normally 12 months) through a rate rider, and consider interest on the accumulated balance. In contrast, API's approach will defer cost recovery of what amount to one-time costs by amortizing the amount over a five-year period. In API's view, the application of the price-cap IR adjustment in future years offsets the fact that no interest calculations are considered on the deferred recovery of the balance (i.e. the amount requested for disposition does not consider interest on the outstanding balance over the 2020-2024 recovery period). This approach is identical to the approach applied to the recovery of other One-Time costs, such as legal fees and consultant costs related to the preparation of cost of service applications.

4-Staff-58

Ref: Exhibit 4 / s. 4.9.1 Overview of PILs
Exhibit 4 / s 4.9.2 Accelerated CCA

Questions:

a) Please provide a copy of the following schedules from API's 2018 Corporate Tax Return:
   i. Schedule 1 (Net Income (Loss) for Income Tax Purposes)
   ii. Schedule 2 (Charitable Donations and Gifts)
   iii. Schedule 4 (Corporation Loss Continuity and Application)
   iv. Schedule 8 (Capital Cost Allowance (CCA))
   v. Schedule 13 (Continuity of Reserves)

b) Please file an updated PILs model, using the most recent OEB-issued version for 2020 rates, ensuring that the historical year reconciles to the above schedules, where applicable.

c) Please repopulate the test year CCA calculated using the format provided for in the 2020 OEB PILs model.

d) Please prepare an analysis showing the impact that the Accelerated CCA program will have on calculated PILs from 2020 to 2024.

e) If the analysis prepared in part d demonstrates significant volatility for the overall calculation of PILs over the five year term, has API considered a smoothing mechanism to address this? Please explain.

RESPONSE:

a) The requested schedules have been filed as:
   "API_IRR_4- Staff-58a - API Corporate Tax Return Schedules.pdf"

b) The updated PILs model has been filed as:
   "API_IRR_2020_Test_year_Income_Tax_PILs_20190814.xlsm"

c) This has been populated in the updated PILs model.

d) See table below. API has excluded the impact of the Echo River Project in 2021 and the Sault Facility Project in 2022 as these have separate ACM models that have been prepared for this Application and include a calculation of PILs. API will include any necessary updates or adjustments to these ACM models to reflect accelerated CCA at the time of requesting approval of the related rate riders in future applications.

	2020 Test	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2020 Test to 2024 Forecast Average CCA
Estimated CCA (Including Accelerated)	8,212,957	8,014,093	8,053,033	8,139,007	7,586,533	8,001,125
Tax Rate	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
CCA PILs Impact	2,176,434	2,123,735	2,134,054	2,156,837	2,010,431	2,120,298
Grossed-up CCA PILs Impact	**2,961,134**	**2,889,435**	**2,903,474**	**2,934,472**	**2,735,281**	**2,884,759**
Difference Grossed-up CCA PILs 2020 Test vs 5 Year Average	**76,375**	**Excess Grossed-up CCA PILs in 2020 Test Over 5 Year Average**				
Difference Pre Gross-up CCA PILs 2020 Test vs 5 Year Average	**60,375**	**Added to T1 Sch 1 Taxable Income Test tab of PILs model**				

Notes:
2021 excludes impact of Echo River Project as ACM has PILs impact included in model
2022 excludes impact of Sault Facility Project as ACM has PILs impact included in model

e) The Grossed-up CCA PILs amounts will significantly vary from $2,735,281 in 2024 Forecast to $2,961,134 in the 2020 Test Year. As a result, API has noted that 2020 Test CCA will be approximately $60,375 ($76,375 grossed-up) higher than the average of 2020 Test to 2024 Forecast. In an effort to smooth this impact, API has added $60,375 to ‘T1 Sch 1 Taxable Income Test’ tab of the PILs model submitted as part of this IR response.

4-Staff-59

Ref: Exhibit 4 / s. 4.12.2 LRAMVA / p. 90
LRAMVA workform / Tabs 2 and 5
EB-2014-0055 / Exhibit 3 / Tab 1 / Schedule 1 / Appendix A / p. 752
EB-2014-0055 / Exhibit 3 / Tab 2 / Schedule 1 / pp. 759-760

Preamble:

In the 2015 cost of service application (EB-2014-0055), API's LRAMVA threshold was based on forecast savings from 2014 and 2015 programs totaling 750,000 kWh. Table 6.2 of Exhibit 3 in API's 2015 cost of service application confirmed the breakdown of the LRAMVA threshold as the sum of 500,000 kWh (2014) and 250,000 kWh (2015). Tables 3.2.1.5 and 3.2.1.6 of Exhibit 3 in API's 2015 cost of service application included the rate class breakdown of the LRAMVA threshold.

Questions:

a) Please explain the basis for increasing the total weather normalized 2015 load forecast from 197,107,462 kWh (Table 3.2.1.5 of Exhibit 3 in the 2015 COS proceeding) to 198,241,007 kWh (Tab 2 of the LRAMVA workform).
b) Please explain the rationale for including actual savings persistence of 2011 to 2013 programs in the LRAMVA calculation, as it appears these values were embedded as actuals in the 2015 load forecast.
c) Please provide a revised LRAMVA workform removing the persistence of 2011 and 2013 programs in 2015 to 2017 with all the necessary adjustments in the LRAMVA workform.

RESPONSE:

a) API's 2015 load forecast was adjusted following a number of undertaking responses during the technical conference in the EB-2014-0055 proceeding. The revised load forecast totaling 198,241,007 kWh was included in the Settlement Proposal approved by the OEB.

b) API agrees that these amounts should be removed from the LRAMVA calculation and has made the necessary adjustments to the revised LRAMVA model filed in conjunction with these interrogatory responses.

c) Please see response to b) above.

4-Staff-60

Ref: Exhibit 4 / s. 4.12.2 LRAMVA / pp. 92-93

Preamble:

API applied an adjustment factor of 0.000196 to the IESO verified kWh savings from 2015 to 2017 to re-calculate the initiative-level peak demand savings. API notes that its kW/kWh ratio is on average 1.85 times higher than the IESO's kW/kWh ratio for the 2015 to 2017 period.

Questions:

a) Please confirm that API seeks to apply the adjustment factor to effectively increase the IESO verified peak savings for all energy efficiency programs by 1.85 times. Then, are the "inflated" demand savings multiplied by 12 (in the LRAMVA workform) to determine annual demand savings to be allocated to the R2 class?
b) Please explain the reason for API's proposed adjustment, specifically:
    i. Whether the purpose of this adjustment is to re-calibrate the IESO's net verified savings to the average demand savings realized by API's R2 class in all 12 months of the year.
    ii. Why it is appropriate to revise the IESO's estimate of net verified peak savings?
    iii. Whether the 1.85x multiplier is accurately determined, as it appears that the total IESO net peak savings should be interpreted as 927 kW x 12 (from Table 22).
c) Please indicate whether API has received endorsement from the IESO to apply an adjustment factor of 0.000196 to kWh savings for all IESO programs from 2015 to 2017.
    i. If yes, please file the correspondence from the IESO in response to this interrogatory.
    ii. If no, please undertake to ask the IESO on the appropriateness of such an approach, and file the response.
d) Please discuss why an adjustment to the demand savings in 2014 and prior years was not required.
e) Please provide the detailed data and calculations in Table 22 to validate accuracy of the annual R2 class (12 month sum) kWh and kW figures from 2015, 2016 and 2017. Please file the analysis in excel format.
f) Please discuss the basis for applying only one adjustment factor of 0.000196 to the IESO's energy efficiency programs, and discuss whether the following was considered:
    i. Adjusting the R2 class billed consumption data for free ridership. What is the assumption applied, if any, and what is that based on?
    ii. Disaggregating the R2 class consumption data (kW and kWh) by commercial and industrial sector. If this can be done, why has API not proposed to do so?
g) If API were to continue to rely on the IESO's net verified savings rather than revising the IESO's peak savings estimates, please quantify the lost revenues and file the supporting LRAMVA workform to show the difference in lost revenues claimed.

RESPONSE:

a) API confirms that the net effect of the adjustment factor increases the IESO verified peak savings by a factor of 1.85. API notes that the 12-month sum of kW provided in Table 22 of Exhibit 4 was provided for the purpose of being able to reconcile this amount to the historical billing determinants provided in Exhibit 3. The factor of 12 was included in the calculation of the API kW/kWh ratio in the last row of Table 22 (e.g. (636,466 / 12) / 270,620,012 = 0.000196) in order to achieve an "apples-to-apples" comparison to the IESO ratio. Stated differently, 0.000196 is the API ratio of annual kWh to average monthly kW demand.

Multiplying the IESO energy savings by a factor of 0.000196 (as API did in the model) therefore produces approximately the same result (difference is due to rounding in the calculation of the ratios) as multiplying the IESO demand savings by 1.85, as shown below:

- 927 (Total IESO verified) x 12 x 1.85 (API/IESO ratio) = 20,579
- 8,730,105 (IESO verified energy) x 12 x 0.000196 (see above) = 20,533

b)

i. The purpose of this adjustment is to re-calibrate the IESO's verified energy savings to the average monthly demand savings realized by API's R2 customers. Since the total annual demand was divided by 12 to calculate the 0.000196 ratio, multiplying the energy savings by 0.000196 results in an average monthly demand savings. This value is then multiplied by 12 in the LRAMVA model to calculate the annual demand savings.

ii. For a number of projects, customer incentives were entirely based on energy reductions and there was no effort to accurately estimate the associated demand savings. In certain cases, no associated demand reduction estimate was reported in the iCON system since they were not required for the purpose of processing the application or incentive payouts, and did not impact the LDC's CFF savings targets, which are energy-based. Since the IESO methodology for certain programs references values reported in the iCON system, the verified savings would therefore understate the demand portion.

iii. API believes that the factor is accurate based on the above responses.

c) The adjustment was simply API's attempt to increase the accuracy of the demand allocations in light of a known issue (see response to b) ii.) that could be adjusted for with little additional effort. This adjustment only affects the LRAMVA balance associated with the R2 rate class (i.e. the only rate class with demand-based distribution rates). Given the immateriality of the financial impact (see part g) below), API did not discuss this approach with the IESO. If the OEB cannot accept the adjustment based on these interrogatory responses, API will revert to using the unadjusted values from IESO.

d) Based on the response to part b) ii. above, API believes this issue is limited to the omission of reporting a demand savings component for certain projects under the 2015 to 2020 CFF framework.

e) These figures are simply the total annual billing determinants for the R2 rate class, which are found throughout Exhibit 3 (see for example Table 2 on page 7).

f)

i. Free-ridership is implicitly included by using the IESO's net verified energy savings since consideration of free-ridership is included in the net-to-gross factors, as documented in the "Methodology" Tab of the IESO's verified annual savings reports.

ii. Since all rates applicable to the R2 rate class, including LRAMVA rate riders, are determined and implemented on an aggregate basis, API sees no value in disaggregating the class consumption data.

g) As discussed in part c), this adjustment only impacts the LRAMVA balance for the R2 rate class. API has filed an alternative version of the LRAMVA model that was updated for all other interrogatory responses (except 4-Staff-61) as "API_IRR_4-Staff-60_Unadjusted Demand.xlsx". The impact of removing API's proposed adjustments is an increase to the credit balance for the R2 rate class by $392 (from $3,523 to $3,915).

4-Staff-61

Ref: Exhibit 4 / s. 4.12.2 LRAMVA / pp. 91-92

Preamble:

Based on an analysis of actual delivery volumes, API states that the IESO verified savings significantly exceed API's actual reduction in street lighting delivery volumes. As a result, API applied three adjustments to reduce the kWh savings that the IESO has verified:

- 2015 incremental savings were reduced by 335,414 kWh
- 2015 persisting savings were reduced by 177,293 kWh
- 2017 incremental savings were reduced by 73,960 kWh

Questions:

a) Please confirm that the kWh reductions to street light savings were applied against the Efficiency: Equipment Replacement Incentive Initiative (EERI) program.

b) Please provide the basis of the statement discussed on page 91 of Exhibit 4:

The results clearly show that the IESO verified savings significantly exceed API's actual reduction in street lighting delivery volumes likely due to a combination of project timing during each year and differences in IESO assumptions for estimating savings as compared to API's billing practices for street lights.

In API's response, please provide the detailed data and analysis to show how the savings reduction was determined for 2015, 2016 and 2017 in Table 21. Please clearly show how the IESO's results for the EERI program are overstated.

c) Please discuss whether the three adjustments made by API were endorsed by the IESO. Please undertake to confirm with the IESO whether or not the reductions that API made are required. Please file the correspondence in response to this interrogatory.

d) Please explain why the adjustment is not required for 2014 and prior years.

e) Please quantify how much lost revenue API is foregoing, had it not reduced savings by the proposed adjustments.

RESPONSE:

a) Confirmed. API notes that it made the actual adjustment in the annual total lines in the LRAMVA model as opposed to the program lines so that the unadjusted program results could more easily be traced back to the IESO verified savings spreadsheet.

b) This statement, and the adjustments, are based on the results in Table 21 on the following page.

For 2015, API's actual billed kWh for Street Lighting was only 62,009 kWh less than its OEB-approved load forecast. In contrast, the IESO's verified savings however indicate a reduction of 397,423 kWh. Since API did not actually experience this reduction, or the associated loss of revenue, it subtracted the difference of 335,414 kWh from the 2015 total so that its LRAMVA recovery would more appropriately reflect the actual revenue lost in that year.

Similarly, API's actual reduction in 2016 billed kWh for Street Lighting, which would have reflected full persistence of 2015 programs, was only 220,130 kWh. API therefore reduced the persistence of 2015 programs by 177,293 kWh (i.e. 397,423 – 220,130).

Finally, for 2017, IESO reported a further 75,999 kWh in energy savings for Street Lighting, but API's billed kWh only decreased by 2,039 kWh compared to 2016 OEB-approved (reduction of 222,168 kWh compared to 2015 OEB-approved). API therefore subtracted the difference of 73,960 kWh (75,999 – 2,039) from the 2017 total so that its LRAMVA recovery would more appropriately reflect the actual revenue lost in that year.

c) The adjustments made by API were not endorsed by the IESO. API requested that the IESO review the adjustments described above. After providing the IESO with the details of this response, they did not have specific data to confirm the impacts to API's street lighting rate class and confirmed that API was in the best position to make the adjustments.

d) No CDM savings were attributed to Street Lighting in 2011-2013. CDM savings in 2014 were minimal, and API actually did observe a reduction in billed kWh that exceeded this amount.

e) API has filed an alternative version of the LRAMVA model that was updated for all other interrogatory responses (except 4-Staff-60) as "API_IRR_4-Staff-61_Unadjusted SL kWh.xlsx". The impact of removing API's proposed adjustments is an increase to the debit balance for the Street Lighting rate class of $169,229.

4-Staff-62

Ref: LRAMVA workform / Tab 3

Preamble:

API's 2016 and 2017 distribution rates were effective in the January 1 rate year, but this is not reflected in the Tab 3 formulas.

Question:

In Tab 3 of the LRAMVA workform, please discuss whether cells J16 and K16 should be revised from 12 to 0 to reflect a January 1 implementation date for 2016 and 2017 rates. If yes, please make the necessary changes in this tab.

RESPONSE:

API agrees that the cells should be revised and has reflected this change in the revised LRAMVA model filed in conjunction with these interrogatory responses.

4-Staff-63

Ref: LRAMVA workform

Preamble:

Section 2.4.6.2 of the Chapter 2 Filing Requirements indicate that distributors should file an excel copy of the savings documentation issued by the IESO to support the figures included in the LRAMVA workform.

Questions:

a) Please file an excel copy of the following reports:
   - 2014 Final CDM Annual Report
   - 2011-2014 Persistence Savings Report
   - 2017 Final Verified Annual CDM Program Results

b) If API made any changes to the LRAMVA work form as a result of its responses to the above LRAMVA interrogatories, please file an updated LRAMVA work form, the revised LRAMVA balance requested for disposition, and a table summarizing the revised rate riders (proposed to be disposed over the next 4 years).

c) Please confirm any changes to the LRAMVA workform in response to these LRAMVA interrogatories in "Table A-2. Updates to LRAMVA Disposition (Tab 2)".

RESPONSE:

a) The first two spreadsheets have been filed as "API_IRR_4-Staff-63_2014 CDM Report.pdf" and "API_IRR_4-Staff-63_2011-2014 Persistence.xlsx". The 2017 verified results were filed on May 17, 2019 as "API 2017 Final Verified Annual LDC CDM Program Results Report 20180629.xlsx"

b) The following table summarizes the LRAMVA balance requested for disposition:

Rate Class	API Proposed (See part c) below)	4-Staff-60	4-Staff-61	4-Staff-60 AND 4-Staff-61
R1	$261,105	$261,105	$261,105	$261,105
R2	-$3,523	-$3,915	-$3,523	-$3,915
Seasonal	$46,375	$46,375	$46,375	$46,375
Street Light	$126,662	$126,662	$295,891	$295,891
Total	**$430,620**	**$430,228**	**$599,848**	**$599,456**

The revised rate riders, using API's proposed balance of $430,620, and updating 2020 billing determinants to align with the revised load forecast model, are as follows:

Rate Class	Units	kWh/kW	Allocated Balance	Rate Rider (Over 4 years)
R1	kWh	113,337,066	$261,105	0.0006
R2	kW	219,709	-$3,523	-$0.0040
Seasonal	kWh	5,784,372	$46,375	$0.0020
Street Light	kWh	581,104	$126,662	$0.0545

c) A revised LRAMVA model has been filed in conjunction with these interrogatory responses that incorporates removal of 2011-2013 results (4-Staff-59) and updating the input for number of months on the Distribution Rates Tab (4-Staff-62). Further, API has filed variations of this model in response to 4-Staff-60 and 4-Staff-61.

For clarity API is not proposing to proceed with the changes in response to 4-Staff-60 or 4-Staff-61 at this time. In the event that API agrees or is directed to incorporate changes from both of these responses, then one of the two models would have to be further revised to reflect all changes.

Exhibit 7

7-Staff-64

Ref: Exhibit 7, pp. 7-10
EB-2018-0271, Decision and Order, April 4, 2019
EB-2018-0271 Application, September 24, 2018

Preamble:

On pages 7-9, API documents its approach for populating the Cost Allocation model for 2020 on the assumption that assets acquired from Dubreuil Lumber Inc. (DLI) will have been completed for the MAADs transaction approved in Decision and Order EB-2018-0271. On page 10 of this exhibit, API also notes that "[c]ertain costs related to the DLI service area were entered in column G of this worksheet and in Sheet I9 these same amounts were allocated directly to the R1 and Street Lighting rate classes as described above [i.e. pages 7-9]". API also notes that, based on current metering information, except for streetlights all customers in the Township of Dubreuilville (Dubreuilville) would be classified as R1 (i) or R1 (ii) per API's established customer classes.

API sought approval for its approach for dealing with the acquisition of DLI in its MAADs/Rates Application (EB-2018-0271). The OEB, in its Decision and Order EB-2018-0271 issued April 4, 2019, did not approve the proposal, stating:

> The OEB does not approve Algoma's proposed approach to allocating costs attributable to the Dubreuil service area in this proceeding. This is a matter that should be determined by the OEB panel hearing the rebasing rate application in which the allocated costs will be reviewed. However, the OEB agrees with Algoma that its approach to integrating Dubreuil costs into Algoma's revenue requirement should be done in a manner that ensures there is no harm to Algoma's existing customers.

API summarizes this also on page 8 of this exhibit.

Question:

Can API demonstrate that its proposed cost allocation approach of integrating DLI's costs into the Cost Allocation Model through its direct allocation does achieve the intended result of ensuring that "there is no harm to Algoma's existing customers"? In other words, what would be the results of the Cost Allocation model if API did not use its proposed direct allocation?

RESPONSE:

API has filed an alternate version of the Cost Allocation model filed with these interrogatory responses, with the direct allocation amounts on Tab I3 zeroed out, as "API_IRR_7-Staff-

64_Remove Direct Allocation.xlsm". The table on the following page compares the class-specific base revenue requirements with and without direct allocation of DLI-related costs.

Revenue Requirement Allocation			**Difference**	
Rate Class	**IRR Updates with Direct Allocation**	**Remove Direct Allocation Amounts**	**$**	**%**
R1	$17,690,028	$17,516,500	($173,528)	-1%
R2	$4,681,930	$4,785,112	$103,182	2%
Seasonal	$3,352,520	$3,421,762	$69,242	2%
Street Light	$178,388	$179,492	$1,103	1%
Total	**$25,902,866**	**$25,902,866**	**$0**	0%

The results of the above table indicate that without API's proposed direct allocation, approximately $69k of DLI-related cost would be allocated to API's Seasonal rate class through the Cost Allocation model. In API's view, since none of the acquired customers are Seasonal, this would not be fair or appropriate.

Please see the response to 7-SEC-35 for further discussion on how the direct allocation approach results in no harm to customers in the R1, R2 and Seasonal rate classes.

7-Staff-65
Ref: Cost Allocation Model / Tab I4 BO Assets

Preamble:

API has $1.9 million gross book value of assets in account 1845 – Underground Conductors and Devices. Of this, 15% is identified as Bulk, 65% as Primary, and 20% as Secondary. There are no assets recorded in account 1840 – Underground Conduit. This implies that API has direct buried (without conduit) all underground conductor, including that operating at bulk and primary voltages.

Questions:

a) Please confirm that API has underground conductors and devices serving these functions in approximately these proportions, or revise if required.
b) Please confirm that API direct buries all its underground conductors, including conductor operating at bulk and primary voltages, or explain where conduit is tracked.

RESPONSE:

a) Please see the response to 7-VECC-39(b).

b) Please see the response to 7-VECC-39(c).

Exhibit 8

8-Staff-66
Ref: Exhibit 8 / s. 8.2.6 / p. 16
RRWF / Tab 12 Res_Rate_Design
Rate Design Model / Tab 6. Rate Design Policy R1(i)

Preamble:

API has calculated a Monthly Fixed Charge of $43.17 and variable charge of $0.0176/kWh before adjustments for the residential rate design policy.

The Rate Design Model calculates that with a proposed fixed charge of $47.17, the resulting variable charge is $0.0126 / kWh. This is based on a recovery of $5.6 million from 8116 R1(i) customers with a combined load of 78 GWh.

API states that "Sheet 12 of the RRWF illustrates that the 2020 adjustment for the R1(i) customer class would be $3.56 if the transition was instead spread equally across the remaining transition years."

Sheet 12 of the RRWF calculates rates based on a recovery of $5.6 million from 9113 R1 customers with a combined load of 104 GWh. This reflects an apparent inadvertent inclusion of R1(ii) customers in the R1(i) rate design. As a result, the rates are initially reduced to a monthly fixed charge of $36.81, and a variable charge of $0.0150 / kWh.

Question:

Please prepare a residential rate design that reflects a 4-year transition to fully fixed rates, and reflects the proposed recovery and billing determinants for the R1(i) customers.

RESPONSE:

The rate design included in Sheet 6 "Rate Design Policy R1(i)" of the rate design model that API filed with the original application achieves a 4-year transition to fully fixed rates. API's proposed rate design would increase the fixed rate by $4 per year for the first three years (2020-2022), and apply the residual amount required to achieve a fully fixed rate in 2023. The following table confirms that applying a $4 increase per year would take more than 3, but less than 4 years:

2020 R1(i) Revenue (A)	2020 R1(i) Customer Count (B)	100% Fixed Rate (C)=A/(Bx12)	Starting Fixed Rate (D)	# of transition years ($4 cap) (E)=(C-D)/4
$5,584,835.67	8,116	$57.34	$43.17	3.54

The above reference was meant to indicate that the default approach in the RRWF calculations results in an equal increase over each transition year, as opposed to API's approach of $4 increments, with the residual in the final year. API acknowledges that the calculations on Sheet 12 of the RRWF inadvertently include customer counts and load from the R1(ii) class, and as such the value of $3.56 is incorrect. Based on the above table, the annual increase, smoothed over 4 years would be $3.54.

API has added a Sheet 6A to the rate design model filed in conjunction with these interrogatory responses that reflects an equal adjustment over 4 years, but proposes to maintain the approach of $4 adjustments in years 1-3 followed by a residual adjustment in year 4.

8-Staff-67

Ref: Exhibit 8 / s. 8.2.8 / p. 19
Rate Design Model / Tab 1. 2019 Equivalent Rates
Rate Design Model / Tab 5. API 2020 Non-RRRP Rate Design
Rate Design Model / Tab 7. Rate Design Policy Seasonal

Preamble:

API states:

> *For the Seasonal rate class, maintaining the current fixed to variable split of 64.09%/35.91% would result in a decrease to the Seasonal fixed rate (prior to the 2020 adjustment under the Residential Rate Design Policy). In API's view, lowering the fixed rate initially to maintain existing fixed to variable ratios would be counter to the Residential Rate Design Policy, and API has therefore proposed to maintain the current fixed rate of $54.75 as the starting point for the 2020 adjustment.*

API calculated the existing fixed / variable split based on 2019 rates of $54.75/month and $0.1494/kWh with a forecast of 3138 seasonal customers with a demand of 7.7 GWh. When it applied the fixed charge of $54.75 / month, it calculated a variable charge of $0.1964 / month. This results in a rate increase which is applied entirely to the variable rate.

To address the rate design policy, API then proposes to increase the fixed charge to $58.75 / month, resulting in a variable charge of $0.1703.

Questions:

a) Please provide the rates that would result by increasing the existing fixed and variable rates by the same percentage to recover the revenue required from the seasonal rate class.
b) Please provide the rates that would result from applying the residential rate design policy to the rates derived in part a)
c) Under API's proposal, and the transition in part b) please indicate the number of years remaining in the transition to fully fixed seasonal rates.

RESPONSE:

In responding to this question, API uses the Seasonal rate class revenue requirement, customer count and load forecast values from the original application. Adjustments resulting from other interrogatory responses have not been factored into revising these values. API notes that either approach requires 6 years of $4 increments to the fixed rate, followed by a residual adjustment of less than $4 in year 7. The approach proposed by API results in Seasonal bill impacts ranging from 7.6% to 8.8% (for RPP customers, depending on consumption), as summarized at page 34 of Exhibit 8. In contrast, adjusting the Seasonal fixed and variable rates on the Rates sheet in API's bill impact model to match the approach in part b) results in total bill impacts ranging from

1.4% to 12.5%. API therefore proposes to maintain the approach set out in Exhibit 8. API's bill impact model, modified to adjust the Seasonal rates to match part b), has been filed as "API_IRR_8-Staff-67 Seasonal Impact Alt Rate Design.xlsx".

a) The rates that would result from this approach are shown in the following table:

	Current Rate	Adjustment	2020 Billing Determinants and Revenue			
			2020 Rate	Customer Count	Load Forecast	Revenue
Fixed	54.75	1.0927	59.83	2960		2,125,162
Variable	0.1494	1.0927	0.1632		5,439,365	887,704
Total				**2960**	**5,439,365**	**3,012,866**

Base Revenue Requirement Allocated to Seasonal Class:		3,013,020
Difference due to Rounding:	$	-154
	%	-0.0051%

b) The rates that would result are shown in the following table:

	Starting Rate	Increase / (Decrease)	2020 Billing Determinants and Revenue			
			2020 Rate	Customer Count	Load Forecast	Revenue
Fixed	59.83	4.0000	63.8300	2960		2,267,242
Variable	0.1632	-0.0261	0.1371		5,439,365	745,737
Total				**2960**	**5,439,365**	**3,012,979**

Base Revenue Requirement Allocated to Seasonal Class:		3,013,020
Difference due to Rounding:	$	-41
	%	-0.0014%

c) For API's proposal, 7 years (including the 2020 adjustment) would be required, as shown in the following table:

2020 Seasonal Revenue (A)	2020 Seasonal Customer Count (B)	100% Fixed Rate (C)=A/(Bx12)	Starting Fixed Rate (D)	# of transition years ($4 cap) (E)=(C-D)/4
3,013,020	2960	$84.83	$54.75	6.52

For the transition in part b), 7 years (including the 2020 adjustment) would be required, as shown in the following table:

2020 Seasonal Revenue (A)	2020 Seasonal Customer Count (B)	100% Fixed Rate (C)=A/(Bx12)	Starting Fixed Rate (D)	# of transition years ($4 cap) (E)=(C-D)/4
3,013,020	2960	$84.83	$59.83	6.25

8-Staff-68
Ref: Exhibit 8 / s. 8.2.6 / p. 17

Preamble:

API proposes to reduce the monthly fixed charge for the street lighting rate class from $2.05 to $1.37, and reduce the variable charge from $0.3310 to $0.3279.

Question:

Please provide the rates that would result by decreasing the existing fixed and variable rates by the same percentage to recover the revenue required from the street lighting rate class.

RESPONSE:

API's approach was based on maintaining the fixed/variable proportions approved in prior applications. The rates that would result from decreasing both rates by the same percentage are shown in the following table:

	Current Rate	Adjustment	2020 Billing Determinants and Revenue			
			2020 Rate	Customer Count	Load Forecast	Revenue
Fixed	2.05	0.9513	1.95	1117		26,138
Variable	0.3310	0.9513	0.3149		595,435	187,502
Total				**1117**	**595,435**	**213,640**

Base Revenue Requirement Allocated to Seasonal Class:		213,627
Difference due to Rounding:	$	13
	%	0.0062%

API notes that the above calculation is based on the Street Light revenue requirement, connection count and load forecast from the original application, and does not reflect responses to other interrogatories.

Exhibit 9

9-Staff-69

Ref: Exhibit 9 / s. 9.3.1 / p. 6 / Table 1 – Account and Balances Sought for Disposition/Recovery
DVA Continuity Schedule Tab 2a
Decision and Order (EB-2018-0017) Table 8.2 Group 1 Deferral and Variance Account Balances

Preamble:

OEB Staff notes that API has entered the following data with respect to principal and interest balances approved for disposition in API's 2019 IRM filing:

		2019			
Account Descriptions	Account Number	Principal Disposition during 2019 - instructed by OEB	Interest Disposition during 2019 - instructed by OEB	Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions during 2019	Closing Interest Balances as of Dec 31-18 Adjusted for Dispositions during 2019
Group 1 Accounts					
LV Variance Account	1550			$0	$0
Smart Metering Entity Charge Variance Account	1551	$2,142	$26	-$5,979	-$23
RSVA - Wholesale Market Service Charge[9]	1580	$252,997	$6,253	-$528,203	-$12,291
Variance WMS – Sub-account CBR Class A[9]	1580			-$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	$1,453	-$49	-$9,362	$2
RSVA - Retail Transmission Network Charge	1584	$29,699	$363	$106,749	$1,281
RSVA - Retail Transmission Connection Charge	1586	-$100,271	-$2,233	$348,832	$5,719
RSVA - Power (excluding Global Adjustment)[12]	1588	$27,828	$4,998	-$70,116	-$4,622
RSVA - Global Adjustment [12]	1589	$291,145	-$5,801	-$741,352	$16,339
Disposition and Recovery/Refund of Regulatory Balances (2012)[7]	1595			$798,611	-$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[7]	1595			-$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[7]	1595			$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[7]	1595			$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595			-$220,548	$178,285
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595			$44,349	$0
Not to be disposed of until a year after rate rider has expired and that balance has been audited					
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$504,994	$3,558	-$277,019	$184,690
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$213,848	$9,359	$464,333	$168,351
RSVA - Global Adjustment 12	1589	$291,145	-$5,801	-$741,352	$16,339

The table below is reproduced from the Decision and Rate Order from EB-2018-0017:

Table 8.2: Group 1 Deferral and Variance Account Balances

Account Name	Account Number	Principal Balance($) A	Interest Balance ($) B	Total Claim ($) C=A+B
Smart Meter Entity Variance Charge	1551	(2,142)	(26)	(2,168)
RSVA - Wholesale Market Service Charge	1580	(252,997)	(6,253)	(259,251)
Variance WMS - Sub-account CBR Class B	1580	(1,453)	49	(1,404)
RSVA - Retail Transmission Network Charge	1584	(29,699)	(363)	(30,063)
RSVA - Retail Transmission Connection Charge	1586	100,271	2,233	102,504
RSVA – Power	1588	(27,828)	(4,998)	(32,826)
RSVA - Global Adjustment	1589	(291,145)	5,801	(285,344)
Totals for all Group 1 accounts		**(504,994)**	**(3,558)**	**(508,552)**

The calculations in the DVA Continuity schedule require that OEB-approved dispositions are entered with the same directional sign as the balances that were approved (debit balance dispositions are entered with a positive figure, credit balance dispositions are entered with a negative figure).

Questions:

a) Please revise the amounts entered in column BM of Tab 2a of the DVA Continuity Schedule to match the figures used in Table 8.2 of the Decision and Rate Order from EB-2018-0017
b) Please perform a review the inputs of balances and transactions throughout Tabs 2a and 2b of the DVA Continuity schedule and confirm that this error is isolated to only column BM of Tab 2a. If any other discrepancies are identified please indicate where they arose and the impact of the correction.

RESPONSE:

a) Please see revised DVA continuity schedule submitted as “API_IRR_API_IRR_9-Staff-69_DVA Continuity Schedule_20190814.xlsb” for corrected balances.

b) A review of the balances has been completed to confirm that no further corrections need to be made to the DVA continuity schedule. API notes that the calculation of the Group 2 rate rider for the Residential – R2 class (i.e. customers with demand >50 kW) reverts to using # of customers in the OEB DVA Model, even if “per kW” is selected. API has calculated used a rate rider of -$0.0525 ($11,529 / 219,709 kW) in the 2020 Proposed Tariff and the 2020 Bill Impact Model filed with these interrogatory responses and will work with OEB staff to correct this calculation in the OEB DVA Model at a later stage in this proceeding.

9-Staff-70

Ref: Exhibit 9 / s. 9.8 / pp. 31 – 35 Global Adjustment

Preamble:

On February 21, 2019 the OEB issued a letter (the "letter"), as well as detailed Accounting Guidance, to all rate-regulated licensed electricity distributors, which stated the following:

"Today, the OEB is providing an initial set of standardized requirements for regulatory accounting and RPP settlements. For some distributors, the result of implementing this guidance may be that changes will be required to their current processes even though the current processes result in accurate balances."

The letter further stated:

"If any distributor is of the view that there may be systemic issues with their RPP settlement and related accounting processes that may give rise to material errors or discrepancies, or if the OEB has identified issues with balances, those distributors are expected to correct those balances before filing for disposition in an annual rate application. Distributors not adjusting balances prior to January 1, 2019 should confirm in their rate application that they have considered the accounting guidance and are of the view that no adjustments are required."

Quuestions:

a) Please confirm whether or not API has incorporated the updated regulatory accounting and RPP settlement guidance into its processes, as of the current date. If so, when did API make these changes? If not, when does API expect to make these changes?
b) If the changes above have already been made, please describe the nature and magnitude of any significant changes required in order for API to comply with the standardization requirements laid out in the guidance.
c) Did API revise any 2018 transactions (or prior years not disposed of on a final basis) within Accounts 1588 or 15899 as a result of implementing the new accounting guidance? If so please itemize a detailed list of the adjustment(s), the reason for the adjustment(s), the dollar impacts, and which cells they are included in within the DVA continuity schedule. If not, please provide confirmation, as indicated in the letter, that API has considered the accounting guidance and is of the view that no adjustments are required.

RESPONSE:

a) In parallel with this proceeding, API continues to make progress on its review of the new accounting guidance released on February 21, 2019 and is striving to meet the August 31, 2019 deadline set out within the letter outlined in the Preamble above. Based on review completed to date, API believes that there will not be any material adjusting entries that will be required for either the 2019 year-to-date or 2018 1588 and 1589 values reported.

b) See response provided in a) above.

c) See response provided in a) above.

9-Staff-71

Ref: 2018 GA Analysis Workform
GA Analysis Workform Appendix A

Preamble:

Reconciling item 13 in the 2018 GA Analysis Workform for $130,000 is described by API as "the overstatement of the December IESO payable accrual for the prior year (CR to be recorded in DVA in prior year), therefore, should record the DR in current year"

In Appendix A to the GA Analysis Workform, Questions 4 b) and e), API identified that the difference between the December 2017 IESO GA Accrual vs IESO GA Actual was ($585,000). $585,000 is also the figure used in the DVA Continuity Schedule to reverse the impact of principal adjustments in 2017 that flowed through the 2018 GL.

Question:

Please reconcile these two figures and explain why $130,000 is being represented as the a reconciling item in the GA Analysis Workform for 2018 rather than the figure of $585,000, which was used in the prior year's IRM application.

RESPONSE:

The $130,000 is the difference between the December 2017 IESO GA Accrual vs IESO GA Actual relating to **Class B Customers**. Reconciling item #12 for $455,000 is the **Class A** customers' portion of the same. The sum of these two reconciling items is $585,000. API presented these amounts in the revised GA Workform submitted in its 2019 IRM interrogatory responses dated November 19, 2019.

9-Staff-72

Ref: GA Analysis Workform Appendix A
DVA Continuity Schedule Tab 2a

Preamble:

Reconciling item 11 in the 2018 GA Analysis Workform for $147,693 is described by API as "the overstatement of the current year Q4 RPP settlement true-up, therefore resulting in an understatement of non-RPP GL transactions in the current year. The RPP settlement true-up occurred in the GL in the following year, therefore, should record the DR in current year."

Questions:

a) Please explain what is meant by an understatement of non-RPP GL transactions for the current year. What kind of transactions (costs, revenues, etc.) are understated and how did that result in Account 1589 requiring a true-up of $147,693 that flowed into 2019's GL?
b) Please explain what is meant by overstatement of current year Q4 RPP Settlement true-up. What specifically was overstated?
c) Please explain why Account 1588 does not have a reciprocal adjusting entry of ($147,693) if this adjustment is the result of misallocating amounts between RPP and non-RPP customers. Alternatively, please explain why such an adjustment would not be required in Account 1588.

RESPONSE:

Preamble to Response:

API would like clarify its comments in the GA Work Form submitted with a revised explanation as follows:

$147,693 relates to current year (2018) Q4 RPP settlement true-up which resulted in a payable to the IESO. Given that the RPP settlement true-up occurred in 2019, record a DR in current year.

a) Please see revised explanation above.

b) Please see revised explanation above. API used 1st GA estimates in initial IESO filings, whereas final GA values were used in the true-up completed. Final GA values were lower than 1st estimates for both November and December; therefore a net payable to the IESO has been calculated.

c) Please see revised explanation above. API has also documented its current IESO settlements process in Section 9.8 of Exhibit 9. As outlined in 9-Staff-70, API continues to make progress on its review of the new accounting guidance released on February 21, 2019 and is striving to meet the August 31, 2019 deadline set out within the OEB letter issued. API believes that there will not be any material adjusting entries that will be required for either the 2019 year-to-date or 2018 1588 and 1589 values reported.

9-Staff-73

Ref: Exhibit 9 / s. 9.3.2 / pp. 11-12 of 43
Exhibit 9 / DVA Continuity Schedule Tab 2b
EB-2013-0368 and EB-2013-0369 Accounting Order
EB-2014-0055 Exhibit 1 / Tab 1 / Schedule 10, page 3 of 3
Exhibit 4 / s. 4.4.3 / Table 9 and Table 11

Preamble:

API has four Group 2 Accounts related to pension and other post-employment benefits costs that resulted from API's adoption of Accounting Standards for Private Enterprises Section 3462 (which disallowed amortization to income of actuarial gains and losses), starting on January 1, 2013. These include two accounts for the transitional amounts upon adoption, as well as two accounts for the annual expense differences between Section 3462 and 3461 (3461, the standard that underpinned rates at the time, previously allowed certain actuarial gains/losses to be amortized to net income).

On page 11 of 43 in Exhibit 9, API states the following with respect to Account 1508 – Other Regulatory Assets – Pension Deferral Sub-Account:

"Due to the reasons outlined in the EB-2013-0368/EB-2013-0369 proceeding requesting the creation of these variance accounts, API is not requesting disposition of the balance of this Sub-Account in this proceeding."

The Accounting Order for the proceeding referred to above was approved as filed on January 9, 2014[1]. In that Accounting Order, the following statements were made by the applicants:

"Disposition of the accounts is proposed to occur in a future cost of service proceeding and will be subject to the Board's prudence review. The proposed recovery through a rate rider will be based on the average remaining service lives of employees in each respective company…No carrying charges will be recorded on these accounts."

In the pre-filed evidence, under Exhibit 1, Tab 1, Schedule 10 (page 3 of 3) in API's subsequent 2015 Cost of Service application (EB-2014-0055), API made the following statements:

"The 2014 Bridge and 2015 Test Year revenue requirement model was developed assuming Section 3461 utilizing the corridor method to smooth P&OPEB expenses. Therefore, within this Application, API is not seeking recovery of any transitional balances, nor is it requesting recovery of any variances calculated for 2013. Instead, API will continue to assess the balances within the established deferral and variance accounts and will look to seek disposition of these balances in a future proceeding."

Questions:

a) Please confirm that, for the purposes of the current application, the same approach has been utilized for 2019 bridge and 2020 test years with respect to estimating P&OPEB expenses (using the corridor method prescribed in the previous Section 3461 rules).

[1] EB-2013-0368 Decision and Order

b) If the above is confirmed, please provide additional detail on how the corridor approach amounts have been calculated by API and whether any actuarial gains/losses are currently included in the P&OPEB costs requested for disposition in the 2020 test year.
c) Please reproduce tables 9 and 11 in Exhibit 4.4.3 to show the actuarial gains/losses that are amortized and included in the Pension and Post-Retirement Benefits Expense line items.
d) Given the material balances that have accumulated on the net amounts of the P&OPEB deferral and variance accounts as of December 31, 2018, please provide rationale for why API has elected not to bring forth these accounts for disposition (or partial disposition).
e) Please provide API's best estimate of what the balances in these four accounts will be (disclosing them separately) after recording the 2019 estimated P&OPEB expense variance amounts.
f) Please provide a more detailed breakdown of how API calculated the variance between P&OPEB expenses from Section 3461 and Section 3462 between 2013 and 2018, showing the amounts calculated under both methods separately (and extended the comparison for estimated 2019, as requested in part e).

RESPONSE:

a) Confirmed.

b) The corridor amounts have been calculated by Mercer (Canada) Limited. The amounts amortized are based on the expected accumulated net actuarial losses (or gains) as of December 31, 2019. Accumulated losses (or gains) in excess of 10% of the expected benefit obligation (i.e. the corridor) are amortized over the expected average remaining service life of active employees. For 2020 Test, Mercer has calculated losses of $54,418 for the pension plan expense and a gain of $76,700 in the OPEB plan expense, both estimates of which have been included within the 2020 Test values presented within this Application.

c) Please see tables below.

Defined Benefit Pension Plan	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Year	2020 Test Year
Pension Expense Excluding Amortized Actuarial (Gains) Losses	$ 333,722	$ 320,493	$ 237,476	$ 362,746	$ 336,165	$ 305,958	$ 284,218
Amortized Actuarial (Gains) Losses	$ 210,447	$ 246,548	$ 7,203	$ 61,820	$ 73,199	$ 79,853	$ 54,418
Pension Expense	**$ 544,169**	**$ 567,041**	**$ 244,679**	**$ 424,566**	**$ 409,364**	**$ 385,811**	**$ 338,636**
Pension Expense Excluding Amortized Actuarial (Gains) Losses Allocated to Capital	$ 108,258	$ 120,277	$ 94,811	$ 120,212	$ 141,942	$ 109,032	$ 102,533
Amortized Actuarial (Gains) Losses Allocated to Capital	$ 68,268	$ 92,527	$ 2,876	$ 20,487	$ 30,908	$ 28,456	$ 19,631
Pension Expense Allocated to Capital	**$ 176,526**	**$ 212,804**	**$ 97,687**	**$ 140,699**	**$ 172,850**	**$ 137,488**	**$ 122,164**
Significant assumptions used:							
Discount rate	4.60%	4.20%	4.00%	3.60%	3.90%	3.70%	3.70%
Expected long-term rate of return on plan assets	5.80%	5.75%	5.50%	5.25%	5.25%	5.25%	5.25%
Rate of compensation increase	4.00%	4.00%	3.50%	3.50%	3.50%	3.50%	3.50%

Post-Retirement Benefits Expense	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Year	2020 Test Year
Post-retirement Benefits Expense Excluding Amortized Actuarial (Gains) Losses	$ 647,100	$ 735,100	$ 618,200	$ 661,200	$ 738,100	$ 516,311	$ 540,111
Amortized Actuarial (Gains) Losses	$ 5,900	$ 83,900	$ -	$ -	$ 21,100	-$ 83,200	-$ 76,700
Post-retirement Benefit Costs	**$ 653,000**	**$ 819,000**	**$ 618,200**	**$ 661,200**	**$ 759,200**	**$ 433,111**	**$ 463,411**
Post-retirement Benefits Expense Excluding Amortized Actuarial (Gains) Losses Allocated to Capital	$ 209,917	$ 275,874	$ 246,813	$ 219,152	$ 311,657	$ 183,993	$ 194,847
Amortized Actuarial (Gains) Losses Allocated to Capital	$ 1,914	$ 31,487	$ -	$ -	$ 8,909	-$ 29,649	-$ 27,670
Post-retirement Benefit Costs Allocated to Capital	**$ 211,831**	**$ 307,361**	**$ 246,813**	**$ 219,152**	**$ 320,566**	**$ 154,344**	**$ 167,177**
Significant assumptions used:							
Discount rate	5.00%	4.20%	4.10%	3.70%	3.90%	3.90%	3.90%

d) As displayed in e) below, the balances in these accounts have significantly varied from year to year, and this volatility is one of the contributing factors as to why API has not put forth any of these balances for disposition.

e) See table below.

P&OPEB Variance accounts				**Ending Balance**			**2019 Estimated**	**Projected**
		31-Dec-14	**31-Dec-15**	**31-Dec-16**	**31-Dec-17**	**31-Dec-18**	**Variance**	**31-Dec-19**
Other Regulatory Assets - Sub-Account - Pension Deferral	1508	6,412,279	6,412,279	6,412,279	6,412,279	6,412,279	-	6,412,279
Other Regulatory Assets - Sub-Account - Pension Expense Variance	1508	(4,173,517)	(4,299,985)	(4,056,880)	(5,516,567)	(6,479,302)	(182,506)	(6,661,808)
Other Regulatory Assets - Sub-Account - Other Post Employment Benefits Deferral	1508	2,518,700	2,518,700	2,518,700	2,518,700	2,518,700	-	2,518,700
Other Regulatory Assets - Sub-Account - Other Post Employment Benefits Expense	1508	(1,222,134)	(2,432,669)	(2,475,684)	(2,550,195)	(5,771,122)	(11,511)	(5,782,633)
		3,535,328	**2,198,325**	**2,398,415**	**864,217**	**(3,319,445)**	**(194,017)**	**(3,513,462)**

f) See tables below.

Defined Benefit Pension Plan	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Year Estimated
Pension Expense Under 3461	403,026	567,041	244,679	424,566	409,364	385,811
Pension Expense (Gain) Under 3462	(1,542,637)	440,573	487,784	(1,035,121)	(553,371)	203,305
Pension Expense Variance Between Section 3461 and 3462	1,945,663	126,468	(243,105)	1,459,687	962,735	182,506

Note: The difference between the $1,945,663 in 2014 above and the $4,173,517 recorded in the DVA continuity in 2014 relates to the change in unamortized transitional obligation and unamortized actuarial losses between January 1, 2013 and January 1, 2014.

Post-Retirement Benefits Expense	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Year Estimated
Post-retirement Benefit Costs Under 3461	623,800	819,000	618,200	661,200	759,200	433,111
Post-retirement Benefit Costs (Gain) Under 3462	498,266	(391,536)	575,185	586,689	(2,461,727)	421,600
Post-retirement Benefit Costs Variance Between Section 3461 and 3462	125,534	1,210,536	43,015	74,511	3,220,927	11,511

Note: The difference between the $125,534 above and the $1,222,134 recorded in the DVA continuity in 2014 relates to the change in unamortized transitional obligation and unamortized actuarial losses between January 1, 2013 and January 1, 2014.

9-Staff 74

Ref: Exhibit 9 / DVA Continuity Schedule Tab 2b – Account 1525/1522

Question:

Please provide additional detail on how the amount of $26,045 was calculated, showing the P&OPEB amounts recorded in reflected in rates in 2018 versus the cash payments made.

RESPONSE:

See table below.

Misc. Deferred Debits 1525/1522		
2018 Activity:		
P&OPEB Costs Included in Rates		(1,197,169)
P&OPEB Cash Payments		665,540
Total Difference of P&OPEB Costs Included in Rates vs Cash Payments		(531,629)
2018 Interest payable using prescribed rates		(7,452)
2019 Projected interest payable on Dec 31, 2018 balance:		
Interest for the first 3 months at 3.82%	(5,077)	
Interest for the last 9 months at 3.39%	(13,517)	(18,594)
Total projected interest payable to Dec. 31, 2019		(26,045)

9-Staff 75

Ref: Exhibit 9 / DVA Continuity Schedule Tab 2b – Account 1508 Sub-account Pole Rental Revenue

Preamble:

API has recorded the excess pole attachment rental revenue earned up to December 31, 2018, which was recognized as a result of the charge increasing from $22.35 to $28.09 in September 30, 2018. API has proposed to defer disposition of these amounts to a future rate proceeding. API also states that the updated pole attachment rates have been incorporated into the calculation of Revenue Offset amounts reported in the 2020 test year.

Questions:

a) Please confirm that API has commencing charging the Pole Rental rate of $43.63 as of January 1, 2019, and has been recording the difference between $43.63 and $22.35 in this sub-account during 2019.
b) Given that there is no correlation between the transactions recorded in 2018 in this account and the pole attachment rates to be incorporated from 2020-2024, please provide rationale for why the 2018 balances should be deferred for disposition?
c) Please provide API's best estimate of what the Pole Rental Revenue sub-account balance will be as of the end of December 31, 2019, given year to date amounts and projections for the remainder of 2019.
d) Does API believe that it can reasonably forecast the December 31, 2019 balance in the Pole Rental Revenue account? If so, what would API's position be with respect to refunding these amounts in the current application and discontinuing this sub-account effective January 1, 2020, rather than deferring disposition and discontinuance of this account to a future proceeding?

RESPONSE:

a) Confirmed.

b) In preparing this application, API was of the view that given that an immaterial amount had accumulated to December 31, 2018 in the DVA account, along with the awareness that variances would continue to accumulate until API rebases, it would be most efficient to seek disposition of the accumulated variance in one proceeding, rather than in multiple proceedings.

c) API estimates that the accumulated variance will be a credit of $249,000 as of December 31, 2019.

d) API believes that it can reasonably forecast the balance and, pending the outcome of the remaining activities of this proceeding (i.e. settlement, hearing, argument), would be agreeable to considering refunding these amounts in the current application and discontinuing this sub-account effective January 1, 2020, rather than deferring until a future proceeding.

9-Staff 76

Ref: Exhibit 9 / s. 9.4 – Retail Service Charges
Chapter 2 Appendices Appendix 2-H Other Operating Revenue
Decision and Order In the matter of energy retailer service charges effective May 1, 2019 (EB-2015-0304)1

Preamble:

API has not reported any activity or balances in Accounts 1518 and 1548 as of December 31, 2018, for the excess of costs over revenues with respect to services rendered for retail services, due to the fact that they are reported to be immaterial.

Questions:

a) Please confirm that API has included the revenues (in Appendix 2-H) and costs (in OM&A) for retail services in its proposed distribution rates using the updated charges outlined in the EB-2015-0304 Decision and Order. If not, please explain why not.
b) Please prepare a table, indicating what the cumulative balances from January 1, 2015 to December 31, 2018 in Account 1518 and 1548 would have been had the associated retail services costs and revenues been recorded.
c) Please confirm that API has implemented the new service charges outlined in the Decision and Order above with respect to retail services as of May 1, 2019. If this is not the case, please explain why not.
d) Please provide API's best estimate of what the cumulative Account 1518 and 1548 balances would be as of the end of December 31, 2019, given year to date amounts and projections for the remainder of 2019 and adding that to the cumulative balances requested in part b) of this question.
e) Does API believe that it can reasonably forecast the December 31, 2019 balances in these accounts? If so, (assuming the balances are not immaterial) what would API's position be with respect to refunding these amounts in the current application and discontinuing these sub-accounts effective January 1, 2020?

RESPONSE:

a) Confirmed.

b) See table below. Total accumulated balance would have been a credit of $12,800.

[1] Decision and Order (EB-2015-0304)

OEB Acct #	Description	2015	2016	2017	2018
Revenues					
4082	Retail Services Revenues	- 5,388	- 5,061	- 4,710	- 4,599
4084	4084-Service Transaction Requests (STR) Revenues	- 77	- 56	- 19	- 34
Costs					
5340	Miscellaneous Customer Accounts Expenses	2,009	1,695	1,115	2,324
Net of Revenues and Costs		**- 3,456**	**- 3,422**	**- 3,614**	**- 2,308**
Cumulative Net of Revenues and Costs Deferred to DVA		**- 3,456**	**- 6,877**	**- 10,491**	**- 12,800**

c) Confirmed.

d) The cumulative balance would be approximately a credit of $18,100 as at December 31, 2019.

e) Given the immaterial projected balance, API's position would remain unchanged from what was submitted in section 9.4 Retailer Service Charges of the Application;

"Due to the non-significant dollars associated with these revenues and expenditures, API has not followed 4 the Article 490, Retail Services and Settlement Variances of the Accounting Procedures 5 Handbook for Account 1518 and Account 1548."

API expects that a credit balance of approximately $2,600 (included in the 2019 cumulative balance of $18,100 noted above) will accumulate in the 1508 Sub-account Retail Service Charges in accordance with Schedule B of Decision and Order of EB-2015-0304 in 2019.

API requests that this Sub-account be closed and, on the basis of immateriality, that disposition of this Sub-account not be sought in either this or any future proceeding.

9-Staff-77

Ref: Exhibit 9, p. 12
COS_DVA Continuity Schedule_20190517.xls
EB-2018-0271 Application, Exhibit F/Tab 3/Schedule 1/p. 2
Decision and Order EB-2018-0271, April 4, 2019
Rate Order EB-2018-0271, June 13, 2019

Preamble:

API had previously been appointed by the OEB as the interim operator of DLI's system pursuant to the Interim Electricity Distribution Licence, Order EB-2017-0153, issued April 4, 2017. Under Order EB-2017-0153, API was authorized to establish a deferral account to track costs related to the operation of DLI offset by revenues received from customers in Dubreuilville by charging DLI's existing rates. In the MAADs/Rates Application, API termed this deferral account as the Interim Licence Deferral Account (ILDA).

API requested approval for the Transaction and Integration Cost Deferral Account (TICDA) to be established effective April 4, 2017 and to transfer the balance of the ILDA, except for an amount of $273k proposed for disposition on an interim basis and being recovered through a $11.16/month rate rider charged to Dubreuilville customers for a period of 6 years.

Decision and Order EB-2018-0271 approved establishment of the TICDA effective September 24, 2018, and also approved partial disposition on an interim basis of the $273k recorded in the ILDA and through a rate rider. The OEB did not approve the transfer of the residual balance of the ILDA to the TICDA.

The OEB's Rate Order in EB-2018-0271, issued June 13, 2019, confirmed the Decision and Order and provided further guidance on the treatment of amounts in the ILDA and TICDA.

In the MAADs/Rates Application, API provided the following table on actual and forecasted amounts in the ILDA and TICDA:[1]

[1] Exhibit F/Tab 3/Schedule 1/p. 2

Nature of Costs	Description	2017 Actual	*2018 YTD (Jan-Jun)*	*2018 Forecast (Jul-Dec)*	2018 Forecast	2019 Forecast
OM&A, Cost of Power, Billed Revenue	Outage and Emergency Response (Includes Locates)	51,999	*40,214*	*40,214*	80,428	80,428
	Meter Reading	54,552	*18,351*	*18,351*	36,702	36,702
	Customer Service and Community Relations	16,498	*529*	*5,000*	5,529	5,000
	Billing & Collections	22,770	*4,367*	*4,367*	8,734	8,734
	Supervisory and Administrative Support	7,014	*2,126*	*2,126*	4,252	4,252
	Cyclical Maintenance	-	-	*6,500*	6,500	10,000
	Cost of Power and Billed Revenue Tracking	8,062	*- 28,435*	*- 28,435*	- 56,870	- 126,823
	Sub-Total OM&A, Cost of Power, Billed Revenue	160,895	*37,151*	*48,123*	85,274	18,292
Capital	Distribution Line Capital (Including Bypass Project)	149,108	*14,138*	*110,000*	124,138	252,000
	Metering Replacements	-	-	*118,140*	118,140	-
	Substation and Underground Capital	-	-	*33,859*	33,859	250,000
	Sub-Total Capital	149,108	*14,138*	*261,999*	276,137	502,000
One-Time	Transfer of Control and Process Development	51,086	*3,664*	*5,000*	8,664	-
	Condition Assessments, Audits, and Reporting	63,065	*53,196*	*10,000*	63,196	-
	Safety, Environmental and Regulatory Compliance	19,466	*14,447*	-	14,447	-
	Substation #1 Decommissioning	-	-	*67,453*	67,453	-
	Substation #2 Transformer Contingency	-	-	*15,000*	15,000	-
	Oil Sampling for PCB Testing	-	-	-	-	80,000
	Sub-Total One-Time Costs	133,617	*71,307*	*97,453*	168,761	80,000
	Total	443,619	*122,596*	*407,576*	530,172	600,292

API filed the current application on May 15, 2019.

OEB staff has prepared the following table based on the entries shown in the DVA Continuity Schedule filed along with this application on May 17, 2019, and on Sheet “2b. 2017 Continuity Schedule” for the following sub-account of Account 1508: Other Regulatory Assets: Sub-account Dubreuilville Costs and Revenues

2017			2018			2019		
Opening Balance (Jan. 1)	Additions	Closing Balance (Dec. 31)	Opening Balance (Jan. 1)	Additions	Closing Balance (Dec. 31)	Opening Balance (Jan. 1)	Additions	Closing Balance (Dec. 31)
$0	$443,619	$443,619	$443,619	$386,492	$830,111	$830,111	$0	$830,111

Questions:

a) Please confirm or correct this table.
b) The 2017 actual appears to correspond with the 2017 actual for the ILDA as documented in the table from the MAADs/Rate Application shown above. Is the sub-account shown in the DVA Continuity Schedule solely with respect to the amounts that API was recording in the ILDA?
c) In the table from the MAADs/Rates Application, API showed a 2018 estimate of $530,172, composed of $122,596 for January-June 2018 actuals and $407,576 July-December 2018 forecasts. This is different from the $386,482 shown as the 2018 additions in the DVA Continuity Schedule. Please provide an explanation for the differences.
d) While acknowledging that 2019 amounts would not be audited, and are not actual for the full year, API has not provided estimates in the DVA Continuity Schedule. However, OEB staff note that estimates are shown in the table from the MAADs/Rates Application.

Please provide an explanation for this difference, and provide updated estimates, if available.

e) With the Decision and Order EB-2018-0271, issued April 4, 2019, and the subsequent Rate Order issued on June 13, 2019, API knows the amounts recorded in the ILDA and the TICDA and for what time periods. Please provide an updated DVA Continuity Schedule that shows the amounts reflecting the EB-2018-0271 Decision and Order and the subsequent Rate Order, with the ILDA and TICDA sub-account balances and entries shown separately. Please provide sufficient explanation for the sub-account entries.

RESPONSE:

a) Confirmed.

b) The sub-account shown in the DVA Continuity Schedule reflects amounts from both the ILDA and the TICDA. The reason that the 2017 amounts are equal is because no transaction costs were incurred in 2017. Please see the response to e) below for a breakdown of the balances.

c) Please refer to the table on the following page, which is extracted from the response to 4-Staff-57. 2018 Variances shown in the table are due to the following:
   - Outage and Emergency Response - less reactive work related to outages, emergency response, and locates in 2018 than what API had estimated based on 2017 actual costs;
   - Distribution Line Capital – reduced requirement for 2018-2019 pole replacement);
   - Metering Replacements – a portion of planned 2018 meter replacement work was deferred to 2019;
   - Substation #2 Transformer Contingency – API was unable to cost-effectively secure spare equipment to improve an interim contingency plan (Substation #2 Transformer Contingency) and certain substation maintenance work was deferred in consideration of the 2020 rebuild of Substation #2;
   - The amount of 2018 One-Time costs identified for transfer from the ILDA to the TICDA was inadvertently included as the 2018 year-to-date costs in the second part of the table instead of 2018 total forecasted costs (i.e. the amount of $71,307 should have been $168,761)[2]; and,

[2] For clarity, API is no longer proposing to transfer this amount to the TICDA, but discusses the variance since the estimate of $551k identified in the application to be recovered through One-Time costs included this error.

- Other immaterial variances.

Nature of Costs	Description	2018 MAAD Forecast	2018 Actual (Audited)	Variance
OM&A, Cost of Power, Billed Revenue	Outage and Emergency Response (Includes Locates)	80,428	52,364	(28,065)
	Meter Reading	36,702	39,257	2,556
	Customer Service and Community Relations	5,529	2,750	(2,779)
	Billing & Collections	8,734	5,291	(3,443)
	Supervisory and Administrative Support	4,252	3,434	(818)
	Cyclical Maintenance	6,500	2,444	(4,056)
	Cost of Power and Billed Revenue Tracking	(56,870)	(68,175)	(11,304)
	Sub-Total OM&A, Cost of Power, Billed Revenue	85,274	37,364	(47,909)
Capital	Distribution Line Capital (Including Bypass Project)	124,138	20,509	(103,629)
	Metering Replacements	118,140	78,841	(39,299)
	Substation and Underground Capital	33,859	4,763	(29,096)
	Sub-Total Capital	276,137	104,113	(172,024)
One-Time	Transfer of Control and Process Development	8,664	16,471	7,807
	Condition Assessments, Audits, and Reporting	63,196	54,499	(8,698)
	Safety, Environmental and Regulatory Compliance	14,447	14,932	484
	Substation #1 Decommissioning	67,453	69,320	1,867
	Substation #2 Transformer Contingency	15,000	-	(15,000)
	Oil Sampling for PCB Testing	-	-	-
	Sub-Total One-Time Costs	168,761	155,221	(13,540)
Total (Excl Transaction Costs)		**530,172**	**296,698**	**(233,474)**
Transaction Costs		**83,674**	**89,794**	**6,119**
Total Cost		**613,846**	**386,492**	**(227,354)**

Description	2018 MAAD Forecast	2018 Actual	Variance
Transaction Costs	83,674	89,794	6,119
Transfer of One-Time Costs from Deferral Account	71,307	155,221	83,913
Transfer of 50% of 2017 OM&A from Deferral Account	-	-	-
Total for Recovery through One-Time Costs	154,981	245,014	90,033

d) Please refer to the table on the following page, which is extracted from the response to 4-Staff-57. 2019 Variances shown in the table are due to the following:

- Outage and Emergency Response - less reactive work related to outages, emergency response, and locates in 2019 than what API had estimated based on 2017 actual costs;
- Meter Reading – continued manual meter reading, slightly increased time to read each new electronic meter (compared to previous dial meters) until AMI system is in place;
- Distribution Line Capital – PCB replacements less than anticipated once test results were received and no priority replacement projects other than planned pole replacements were identified;
- Metering Replacements – a portion of planned 2018 meter replacement work was deferred to 2019;
- Substation and Underground Capital – costs related to substation engineering will be CWIP only for 2019 (i.e. removed cost from 2019 and added to 2020 to reflect timing of capitalization instead of expense);
- Oil Sampling - Costs less than budgeted;
- While API did not incur $60k in intervenor costs originally included in its 2019 transaction costs forecast, this was largely offset due to higher than anticipated legal costs during the IRR and Draft Rate Order portions of EB-2018-0271, as well as higher than anticipated legal costs related to the closing of the commercial transaction;
- Similar to 2018, the amount of 2019 One-Time costs identified for transfer from the ILDA to the TICDA was inadvertently included as the 2018 July-Dec forecasted costs in the second part of the table instead of 2019 forecasted costs (i.e. the amount of $97,453 should have been $80,000)[3]; and,
- Other immaterial variances.

[3] For clarity, API is no longer proposing to transfer this amount to the TICDA, but discusses the variance since the estimate of $551k identified in the application to be recovered through One-Time costs included this error.

Nature of Costs	Description	2019 MAAD Forecast	2019 Revised Forecast	Variance
OM&A, Cost of Power, Billed Revenue	Outage and Emergency Response (Includes Locates)	80,428	20,000	(60,428)
	Meter Reading	36,702	55,000	18,299
	Customer Service and Community Relations	5,000	1,000	(4,000)
	Billing & Collections	8,734	8,500	(234)
	Supervisory and Administrative Support	4,252	3,434	(818)
	Cyclical Maintenance	10,000	10,000	-
	Cost of Power and Billed Revenue Tracking	(126,823)	(120,578)	6,245
	Sub-Total OM&A, Cost of Power, Billed Revenue	18,292	(22,644)	(40,936)
Capital	Distribution Line Capital (Including Bypass Project)	252,000	170,000	(82,000)
	Metering Replacements	-	30,000	30,000
	Substation and Underground Capital	250,000	-	(250,000)
	Sub-Total Capital	502,000	200,000	(302,000)
One-Time	Transfer of Control and Process Development	-	-	-
	Condition Assessments, Audits, and Reporting	-	1,300	1,300
	Safety, Environmental and Regulatory Compliance	-	-	-
	Substation #1 Decommissioning	-	5,362	5,362
	Substation #2 Transformer Contingency	-	-	-
	Oil Sampling for PCB Testing	80,000	52,989	(27,011)
	Sub-Total One-Time Costs	80,000	59,651	(20,349)
Total (Excl Transaction Costs)		**600,292**	**237,007**	**(363,285)**
Transaction Costs		**85,000**	**80,000**	**(5,000)**
Total Cost		**685,292**	**317,007**	**(368,285)**

Description	2019 MAAD Forecast	2019 Revised Forecast	Variance
Transaction Costs	85,000	80,000	(5,000)
Transfer of One-Time Costs from Deferral Account	97,453	59,651	(37,802)
Transfer of 50% of 2017 OM&A from Deferral Account	-	-	-
Total for Recovery through One-Time Costs	182,453	139,651	(42,802)

e) The DVA continuity schedule does not allow for 2019 entries. Since API has not used the DVA continuity schedule for the purpose of requesting disposition of these accounts, the requested breakdown is provided in the following table, consistent with the costs in the spreadsheet provided in response to 4-Staff-57:

	2017			2018			2019 (Forecast)		
	Opening Balance (Jan. 1)	Additions	Closing Balance (Dec. 31)	Opening Balance (Jan. 1)	Additions	Closing Balance (Dec. 31)	Opening Balance (Jan. 1)	Additions	Closing Balance (Dec. 31)
ILDA	$0	$443,619	$443,619	$443,619	$367,522	$811,142	$811,142	$237,007	$1,048,148
TICDA	$0	$0	$0	$0	$18,969	$18,969	$18,969	$80,000	$98,969
TOTAL	**$0**	**$443,619**	**$443,619**	**$443,619**	**$386,492**	**$830,111**	**$830,111**	**$80,000**	**$1,147,118**

1-SEC-1
[Ex.1] Please provide all material provided to the Applicant's Board of Directors regarding its approval of this application and the underlying budgets.

RESPONSE:

Material provided to API's Board of Directors at its June 5, 2019 meeting has been filed as "API_IRR_1-SEC-1_Board Agenda API COS.pdf". During the meeting, the Board was also provided with information on how to find all documentation related to the proceeding.

1-SEC-2
[Ex.1] Please provide copies of all benchmarking studies, reports, and analysis that the Applicant has undertaken or participated in since its last rebasing application in 2014, that are not already included in the application.

RESPONSE:

API has not undertaken or participated in any benchmarking activities since 2014 that are not already included in the application.

1-SEC-3
[Ex.1] Please provide a step-by-step explanation of the Applicant's budgeting process.

RESPONSE:

With exception to any acceptable cost drivers (positive or negative), API management forecasts year-over-year changes to API's total OM&A budget to generally be in line with inflationary increases, along with a consideration of API's stretch factor.

When preparing its annual operations, maintenance and administration budget, API management considers the operational needs and requirements of the organization for the upcoming year. To the extent possible, planned human resources, purchased services, materials and other costs are all identified and accounted for during the budgeting process. API forecasts its budget based on a review of its planned work to achieve the planned OM&A activities, and its historic costs, consideration of feedback obtained through customer engagement, and identified priorities for maintenance programs and capital projects based on asset condition information available. Consideration is also given to the required and available resources, both internal and external. Budget increases are constrained and reviewed by considering available resources including revenue forecasts. The 2020 Test Year budget preparation commenced in the third quarter of 2018, with additional modifications being finalized in 2019 in advance of this Application submission.

With respect to the maintenance budget, API considers information gathered through the processes identified in the Asset Management Plan, which is an Appendix to API's Distribution System Plan ("DSP"), described at Exhibit 2. Information is gathered from various sources, including inspections, testing and asset condition assessments. The information is reviewed in consideration of required and available resources, and is compared to historical activity patterns. The resulting maintenance budget assists API in implementing an effective maintenance program that is expected to maximize the operational life of assets in service, and to enhance the safe and reliable supply of electricity to consumers in the service territory.

In preparation of its capital budget, API has been guided by the expectations set out by the Board, contained in the Chapter 5 Filing Requirements. This has resulted in the updating of API's DSP, which describes API's proposed capital programs and projects, both in the 2020 Test Year, and in the 2021-2024 horizon.

Management is responsible for preparing the budgets of the respective departments including operating and capital budgets. Labour hours are allocated to capital, operating and maintenance, or billable job orders. Non-labour costs are also taken into account.
A revenue model is prepared based on existing distribution rates and forecast loads as explained in Exhibit 3. The load forecast is reviewed and approved by the Executive group.

The operating and capital budgets are reviewed by management prior to allocations for shared corporate services. The shared corporate services allocations are reviewed and approved separately by the Executive group. The finance department is responsible for managing the budgeting process.

The Executive group reviews the prepared operating and capital budgets, including the shared corporate service allocations, with respective managers. Based on this review, any further modifications to the budget are made before being finalized for presentation to the Board of Directors. The Board of Directors reviews, requests modifications if appropriate, and then subsequently approves the operating and capital budgets annually.

The revenue requirement, and rate base were approved by the Board of Directors for this Application as outlined in 1-SEC-1.

1-SEC-4

[Ex.1] Please provide details of all productivity and efficiency measures the Applicant has taken since its last rebasing application in 2014.

RESPONSE:

Customer Focus	24/7 call centre for outage calls
	Advance planning, engineering & coordination with transmitter - lessen outage times
Planning	Use LiDAR technology to provide power line and ground features survey information for designing projects. LiDAR ($1k /km) versus traditional survey ($40k /km)
	Establishment of Field Planning - Focus on coordinating work activities on a project between lines, electrical and forestry. (DSP 2.3.2.2.1 - Methods and Measures)
	Online mapping tools, as well as databases of asset and property information are reviewed in the office in advance of site visits to determine options
	Site visits with customers/contractors are grouped by area to minimize travel time and costs. Activities such as tagging, commissioning and data collection are also scheduled around these visits to take advantage of mobilization to remote areas
	For each service request, technicians identify whether any minimal scope connection options exist that will both meet the customer's requirements and the requirements of regulation 22/04
	For connections where minimal scope options are not available, opportunities to incorporate efficiencies are considered (e.g. changing additional poles to take advantage of line crew and equipment mobilization)
	Utilize vegetation management software for vegetation management reporting and data collection at API
	Utilization of GPS technology for collecting spatial information of API assets while in the field
	Use of computer engineering software to design and prepare construction drawings, leveraging LiDAR information, GIS, and Google Earth
Operational Effectiveness	Lines using “porta-holes” and rock augering in advance of setting poles reducing outages and over all pole installation costs
	Project work performed in the winter – reducing environmental impacts and some access issues
	Monthly project reviews to discuss issues and review timing of work (DSP 2.3.2.2.1 - Methods and Measures)
	Produced Arc Flash mapping to identify Arc Flash hazard potential locations, used to determine daily work methods
	Express feeder inspections increased to twice a year in to reduce reactive work and significant outages
	Wawa yard and transformer stand (DSP 4.3.2.2 Facilities)
	SKYPE meetings and usage
	Construction of the new Desbarats Work Centre (4.3.2.2 Facilities)
	Installation of circuit fault indictors on major feeders

1-SEC-5

[Ex.1] Please provide details of all productivity and efficiency measures the Applicant plans to take in the test year. Please quantify the forecast savings.

RESPONSE:

Please refer to the DSP Section 2.1.3 Anticipated Sources of Cost Savings (5.2.1c), as well as the response to 1-SEC-4.

The overall impact of recent productivity and efficiency measures has resulted in the following cost savings that have been factored into 2020 forecasts:

- For Distribution Line Rebuilds, API's forecasted unit cost per pole for the 2020-2024 period of $7,500 is lower than its 2015-2019 historical costs of $7,620 (see response to 2-Staff-15(b), which in turn are lower than the forecast of $8,500 per pole included in API's prior DSP.
- Outage response costs included in O&M have trended downward from 2015 to 2020, as shown in Appendix 2-JB (page 23 of Exhibit 4).
- API has managed to address the following cost drivers, without increasing its FTE count (see 4-VECC-28(b)):
    - Integration of the assets and customers historically served by DLI, including ongoing asset inspection and maintenance requirements, outage response, meter reading, billing and customer service; and,
    - A requirement to apply non-linear design principles (which is more time-consuming as compared to the prior linear design approach) to its 500 pole per year replacement program and new service connection requests.

1-SEC-6

[Ex.1; Ex.4, p.45] Please provide a copy of the Applicant's 2015 to 2019 corporate targets/scorecard. Please provide both the targets and the results.

RESPONSE:

FortisOntario operates various regulated utilities in Ontario, one of which is Algoma Power. FortisOntario's corporate targets are based on consolidated operating and capital expenditures, safety performance measures, customer satisfaction results and reliability targets. Each of the corporate targets benefits the ratepayers. Below are FortisOntario's corporate targets (and results) from 2015-2019.

2015 Corporate Short-term Incentive Target Results

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	30%	Consolidated Operating Expenses ($'000)	Budget +10% $35,731	Budget $32,483	Budget -10% $29,235
	20%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Subjective	Budget $28,222	Subjective
Customer Service	15%	Customer Satisfaction	81%	83%	85%
Safety	10%	All Injury Frequency Rate (AIFR)	4.1	3.7	3.3
	10%	# of Safety Field Observations for the Company	90% of total	308	Subjective
Reliability	15%	The average duration of outages per customer (SAIDI) for the Company	3.28	2.73	2.19

2015 Corporate Results – 127%

2016 Corporate Short-Term Incentive Target Results

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	30%	Consolidated Operating Expenses ($'000)	Budget + 10% $35,230	Budget $32,027	Budget - 10% $28,824
	20%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Subjective	Budget $25,060	Subjective
Customer Service	15%	Customer Satisfaction	88%	90%	94%
Safety	10%	All Injury Frequency Rate (AIFR)	3.9	3.5	3.2
	10%	Planned Work Observations & Workplace Inspections (% of Planned 455)	90%	100%	120%
Reliability	15%	Outage Duration Index (SAIDI) for FortisOntario	3.47	2.89	2.31

2016 Corporate Results – 110.9%

2017 Corporate Short-Term Incentive Target Results

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	25%	Consolidated Operating Expenses ($'000)	Budget +10% $34,839	Budget $31,672	Budget -10% $28,505
	25%	Effectively Manage/Optimize Consolidated Regulated Capital Plan (Net) ($'000)	Subjective	Budget $25,528	Subjective
Customer Service	15%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +2%	Subjective
Safety	10%	All Injury Frequency Rate (AIFR) [2]	4.5	Target 3.3	2.81
	10%	Planned Work Observations & Workplace Inspections (% of Planned 420) [3]	Target - 10% 410	Target 420	Target + 20% 504
Reliability	15%	Outage Duration Index (SAIDI) for FortisOntario [4]	Target + 20% 3.49	Target 2.91	Target - 20% 2.33

1 Target is Ontario Benchmark conducted by UtilityPULSE +2%.

2 AIFR 100% target is based on a 5 year rolling average and range is based on a +/- 10% band.

3 420 Work Observations and Workplace Inspections were planned for 2017.

4 SAIDI 100% target is based on a five-year rolling average. The target for 2017 is 2.91.

2017 Corporate Results – 130.0%

2018 Corporate Short-Term Incentive Plan Results

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	25%	Consolidated Operating Expenses ($'000) [1]	Budget +10% $34,839	Budget $31,672	Budget -10% $28,505
	25%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Subjective	Budget $25,528	Subjective
Customer Service	15%	Customer Satisfaction [2]	Subjective	Ontario Benchmark +3%	Ontario Benchmark +5%
Safety	10%	All Injury Frequency Rate (AIFR) [3]	3.95	Target 2.87	1.13
	10%	Planned Work Observations & Workplace Inspections [4]	Target -10% 416	Target 462	Target +20% 554
Reliability	15%	The average duration of outages per customer (SAIDI) for FortisOntario [5]	Target +20% 3.47	Target 2.89	Target -20% 2.31

[1] Includes adjustments for CDH (i.e., not included in the Plan) and pension and post-retirement expense adjustments relating to CPA Handbook Section 3462.

[2] 2018 Target is Ontario Benchmark conducted by UtilityPULSE +3%.

[3] 2018 AIFR 100% target is based on a five-year rolling average and range based on number of medical aids and/or lost time injuries.

[4] 462 Work Observations and Workplace Inspections were planned for 2018.

[5] 2018 SAIDI 100% target was based on a five-year rolling average. The 2018 target is 2.89.

2018 Corporate Results – 122.2%

2019 Corporate Short-term Incentive Plan Targets

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	20%	Consolidated Operating Expenses ($'000)	Budget +10% $36,774	Budget $33,431	Budget -10% $30,088
	15%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Target -15% $22,877	Budget $26,914	Subjective
	15%	Cash Flow from Operations Before Working Capital ($'000)	Target -3% $26,967	Budget $27,801	Budget +3% $28,635
Customer Service	15%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +3%	Ontario Benchmark +5%
Safety	15%	All Injury Frequency Rate (AIFR) [2]	3.00	Target 1.66	0.00
	5%	Planned Work Observations & Workplace Inspections [3]	Target -10% 392	Target 436	Target +20% 523
Reliability	15%	The average duration of outages per customer (SAIDI) for FortisOntario	Target +20% 3.33	Target 2.77	Target -20% 2.22

1 2019 Target is Ontario Benchmark conducted by UtilityPULSE +3%.

2 2019 AIFR 100% target is based on a 3 -year rolling average less 26% (equivalent to 3 incidents - i.e., medical aids and/or lost time injuries). The minimum 50% is equivalent to appoximately 6 incidents, and maximum 150% is 0 incidents.

3 2019 SAIDI 100% target is based on a three-year rolling average less 5%.

2019 Corporate Results - TBD

1-SEC-7
[Ex.1, p.62] Please provide details regarding what changes the Applicant made to the underlying plan or the application as a result of its customer engagement activities.

RESPONSE:

These details are provided in Table 18, at pages 69-71 of Exhibit 1.

1-SEC-8
[Ex.1, App 1B, p.22] Please provide a copy of the referenced analysis of cost drivers in the PEG total cost benchmarking model that was contained in its EB-2013-0110 application.

RESPONSE:

A copy of the referenced analysis has been filed as “API_IRR_1-SEC-8_Analysis from EB-2013-0110.pdf”

1-SEC-9
[Ex.1, App 1B, App B] Please provide a copy of the full script/workbook for the Talking A.I.M. Survey.

RESPONSE:

The full Taking AIM script/workbook has been files as “API_IRR_1-SEC-9_AIM Online Survey Book.pdf”

1-SEC-10
[Ex.1, p.20] With respect to the acquisition of the Dubreuil Lumber Inc. distribution system:

a. Please provide a copy all OEB decisions related to the Applicant's appointment of the interim operator of the Dubreuil Lumber Inc. distributor system and subsequent MAADs transaction.
b. The Applicant states that "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.". Please explain what the Applicant means procedurally by a Preliminary Issue.
c. Please explain why it is appropriate to allocate the balance of the Interim License Deferral Account to all the Applicant's customers and not only the former Dubreuil Lumber Inc. customers. Please provide revised bill impacts if those costs were solely allocated to the former Dubreuil Lumber Inc. customers.

RESPONSE:

a) API has filed a consolidated document "API_IRR_1-SEC-10_DLI Decisions.pdf", which contains the following OEB decisions:
   - The initial April 4, 2017 decision, granting API an interim distribution licence to operate the electricity distribution system in the Township of Dubreuilville, and requiring Dubreuil Lumber Inc. to surrender possession and control of the electricity distribution system in the Township of Dubreuilville to API;
   - Subsequent decisions, extending the term of API's interim licence, dated October 3, 2017; April 3, 2018; October 3, 2018; and April 2, 2019;
   - The OEB's Decision and Procedural Order #2 in the MAAD proceeding, dated February 5, 2019;
   - The OEB's Decision and Order in the MAAD proceeding, dated April 4, 2019; and
   - The Final Rate Order in the MAAD proceeding, dated June 13, 2019

b) The language referenced was removed in the updated application filed on June 3, 2019.

c) For clarity, API is not proposing to allocate the entire balance of the Interim Licence Deferral Account to all of its customers. A portion of the balance, is being recovered from the former DLI customers, through a monthly rate rider of $11.16 per customer per month, established in the MAAD proceeding, which is effective for 6 years. It is only the remaining balance that API is proposing to recover through its revenue requirement, by including capital investments in rate base, and by amortizing one-time, transaction and integration costs over the 2020-2024 rate setting period. The rationale for this approach was discussed in detail in Exhibits F-3-1 and F-3-2 of the MAAD application, which have been filed as "API_IRR_1-SEC-10_DLI Deferral Accounts.pdf"

In the MAAD application, API calculated that the $11.16 rate rider would increase to $27.72 if the remaining book value of the 2017-2019 capital investments in the DLI system was not transferred to API's rate base in 2020. Further, the $11.16 rate rider results from recovering approximately $284k from the former DLI customers over a period of 6 years. The one-time, transaction and integration costs that API is proposing to amortize over the 2020-2024 period are approximately double this amount, meaning that a further approximately $22 rate rider would be required to recover those costs from former DLI customers. The total rate rider required to recover all interim costs from the former DLI customers only is therefore approximately $50 per month ($27.72 + approximately $22). This would result in a bill impact of approximately 34% for a typical residential customer, on top of the approximately 15% bill impact experienced in August 2019 when API's rates and the $11.16 rate rider came into effect. In API's view, this is clearly not an appropriate approach.

In contrast, as explained in response to 7-SEC-35, the approaches to cost recovery and cost allocation proposed by API result in zero bill impact on API's the vast majority of API's existing customers (i.e. all customer other than the Street Lighting rate class), and a positive impact on the Street Lighting rate class.

2-SEC-11
[Ex.2] Please revise Appendix 2-AA by adding a column showing year-to-date 2019 actuals.

RESPONSE:

June 2019 year-to-actuals per Appendix 2-AA have been provided in tables below.

Appendix 2-AA
Capital Projects Table

Reporting Basis	Reporting Basis		MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Projects	Projects	USoA	2015	2016	2017	2018	2019	2020	2019
									JUN YTD
System Access	**System Access**		2015	2016	2017	2018	2019	2020	2019
	New Meters		$63,907	$102,942	$107,367	$23,492	$48,114	$67,399	$71,963
	New Cust Additions OH - Wawa		$70,247	$80,787	$73,580	$79,070	$94,195	$87,706	$24,476
	New Transformers - Service		$31,139	$128,823	$42,080	$63,463	$76,800	$76,800	$23,064
	New Cust Additions OH - Desb		$76,597	$232,268	$225,733	$267,189	$233,483	$224,737	$93,098
	New Cust Additions UG - Desb		$269,617	$2,644	$1,927	-$820	$11,186	$11,442	-$100
	New Cust Additions OH - Sault		$187,803	$364,254	$431,992	$469,220	$391,587	$367,882	$197,876
	New Cust Additions UG - Sault		$221,692	$13,743	$0	$654	$17,714	$16,562	$0
	Miscellaneous SA		$42,142	$66,080	$495	$58,004	$39,626	$50,880	$54,328
Contributed Capital									
			-$147,270	$71,036	-$78,475	-$64,304	-$140,000	-$101,850	-$102,191
Total System Access	**Total System Access**		**815,874**	**1,062,577**	**804,699**	**895,967**	**772,704**	**801,557**	**362,514**

Appendix 2-AA
Capital Projects Table

Reporting Basis	Reporting Basis		MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Projects	Projects	USoA	2015	2016	2017	2018	2019	2020	2019
									JUN YTD
System Renewal	**System Renewal**		2015	2016	2017	2018	2019	2020	2019
	API Storm Rebuilds - Wawa		34,817	35,339	35,514	0	40,648	40,316	
	API Storm Rebuilds - Desbarats		$98,145	$34,910	$137,605	$28,979	$109,033	$98,219	$12,148
	API Storm Rebuilds - Sault		$60,314	$49,516	$43,062	$31,584	$71,095	$66,797	$21,958
	API Small Lines Capital - Wawa		$128,955	$192,946	$75,220	$66,815	$94,416	$103,240	$45,738
	API Small Lines Capital - Desb.		$224,607	$160,132	$95,726	$171,560	$129,150	$139,178	$61,992
	API Small Lines Capital - Sault		$211,995	$101,782	$144,253	$179,743	$132,132	$150,143	$105,330
	API Replace Recloser, Regulator, etc.		$107,833	$101,949	$82,299	$98,453	$80,224	$81,828	
	Cond Repl - Centre Line Rd. (Phase 2)		$188,406						
	Cond Repl - Neal Dr, Old Moffat Bay, Big Pit		$143,516						
	Line Rebuild - Along Hwy 17 North from MTO yard to Northwood Dr		$468,412						
	Line Rebuild - 20th Side Rd/I Line/V Line Rd SJI		$383,504						
	Pole Replacement From Pole Testing Program		$237,844	$181,083	$128,963	$430,249			$411,441
	Line Rebuild - Along Hwy 17 South of Frater Rd			$519,322					
	Line Rebuild - Shore Rd			$307,701					
	Line Rebuild - River side, Lake side off Boyles side Rd			$293,597					
	Line Rebuild - Tamawa Rd off Hwy 17N			$242,072					
	Line Rebuild - Four Seasons Drive			$183,678					
	Line Rebuild - Hillton Rd (Base Line to Hilton Beach)			$177,364					
	Line Rebuild - HWY17 Batchewana Bay P102-P129			$114,819	$164,195				
	Line Rebuild - Hwy 532 to end of line				$648,569	$157,274			$26,037
	Line Rebuild - HWY17 Wawa P1-P110				$472,635				$50,178
	Line Rebuild - Hwy 552 West				$258,639				$126
	Line Rebuild - B-Line				$180,631				
	Line Rebuild - Hwy17N at step up xfmr to mirian lake				$156,153	$677,496			$24,558
	Line Rebuild - Pancake to Mamainse					$604,455			$4,784
	Line Rebuild - Hwy 17W of MacLennan Rd					$343,873			$84,130
	Line Rebuild - Mackay to Rabbit Blanket					$236,772			$407,197
	Line Rebuild - 10th Side Rd (f&g to d line)					$215,151			$1,560
	Line Rebuild - F&G Line between 10th Side & A Line					$151,328			
	Line Rebuild - McKinley Ave Wawa					$114,560			
	Line Rebuilds (See DSP for Add'l Detail)						$3,380,789	$2,783,072	
	Wawa 34kV Rebuild		$519,282		$191,761	$374,369			
	No 4 Circuit Rebuild		$164,270	$1,038,639	$272,240	$612,436			
	API SubTransmission Rebuilds (Small)		$72,825	$11,574	$8,270	$82,615			$18,971
	SubTransmission Rebuilds (See DSP for Add'l Detail)						$969,207	$912,061	
	API NewTransf-Replace Failed/End of Life		$53,455	$18,762	$29,166	$30,203	$76,800	$76,800	$20,343
	API Substation Small Capital		$61,118	$63,504	$50,034	$2,660	$60,364	$42,740	$3,819
	Substation Capital - Dubr							$1,245,949	
	Line Rebuild - Hwy 552 East, post office rd to turmain rd								$257,017
	Miscellaneous SR		$649,358	$400,231	$258,953	$360,114	$0	$24,798	$104,161
Contributed Capital									
			$0	-$43,752	-$54,003	-$4,959			
Total System Renewal	**Total System Renewal**		**3,808,657**	**4,185,167**	**3,379,887**	**4,965,729**	**5,143,857**	**5,765,139**	**1,661,487**

Appendix 2-AA
Capital Projects Table

Reporting Basis	Reporting Basis		MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Projects	Projects	USoA	2015	2016	2017	2018	2019	2020	2019
									JUN YTD
System Service	**System Service**		2015	2016	2017	2018	2019	2020	2019
	API New Transf-Volt Conv/Capacity Incr		$19,590	$62,243	$26,425	$47,180	$38,400	$38,400	
	Hawk Junction DS rebuild		$2,805,052	$771,046					
	API Protection Automation Reliability		$102,675	$156,669	$16,486	$122,337	$286,944	$256,832	
	API Sub/Subtrans Reliability Improvement		$105,951	$0	$16,446	$122,500	$263,346	$267,094	
	API Desbarats DS Projects				$1,378	$47,016	$279,625		$49,343
	Mackay API primary metering relocation				$131,705				
	Miscellaneous SS								$113,008
Contributed Capital									
			$0	$0	$0	$0	$0	$0	
Total System Service	**Total System Service**		**3,033,268**	**989,959**	**192,439**	**339,032**	**868,315**	**562,326**	**162,351**

Appendix 2-AA
Capital Projects Table

Reporting Basis	Reporting Basis		MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Projects	Projects	USoA	2015	2016	2017	2018	2019	2020	2019
									JUN YTD
General Plant	**General Plant**		2015	2016	2017	2018	2019	2020	2019
	API Right Of Way Expansion and Access		$1,715,771	$1,554,505	$1,563,220	$1,129,615	$97,336	$99,660	$12,674
	API Distribution Tools & Equipment		$45,316	$60,944	$109,172	$82,854	$94,360	$96,248	$35,087
	API Vegetation Mgmt System Development		$110,660	$21,318	$437	$210			
	API Land Rights		$29,159	$30,834	$15,958	$51,962	$25,809	$28,605	$11,209
	API SCADA		$51,695	$9,815	$4,916	$15,186	$93,599	$92,880	$12,656
	API Transportation & Work Equipment		$437,311	$537,569	$605,784	$454,300	$621,413	$661,609	$40,325
	API IT - Hardware		$178,080	$32,950	$60,354	$126,128	$149,002	$227,400	$9,902
	API-Specific Engineering Soft. Develop.		$41,323	$39,713	$115,254	$114,123	$63,913	$38,980	
	API Building Desbarats		$26,005	$30,667	$4,878	$875,895	$103,734	$24,154	$17,852
	API Building Wawa		$326,920	$33,520	$404,370	$299,578	$154,893	$24,154	$117,898
	API Building Sault								$42,032
	Miscellaneous GP		$121,652	$17,308	$78,456	$90,392	$95,730	$63,028	$13,866
Contributed Capital									
			-$9,848	$0	-$4,054	$0			
Total General Plant	**Total General Plant**		**3,074,045**	**2,369,143**	**2,958,744**	**3,240,243**	**1,499,788**	**1,356,717**	**313,501**

2-SEC-12
[Ex.2] Please provide a single line drawing of the Applicant's distribution system.

RESPONSE:

A copy of Algoma Power's single line diagram has been included in Section 3.2.2 of the DSP (see figure 3.3).

2-SEC-13
[Ex.2, DSP, p.29] Please provide the Applicant's SAIDI and SAIFI (excluding MED and LOS) targets for each year between 2020 and 2024.

RESPONSE:

API sets its reliability targets early in each year, based on the average of the results of the 3 most recent years, minus 5% for continuous improvement. API is therefore unable to provide specific targets for 2020 to 2024 at this time.

2-SEC-14

[Ex.2, DSP, p.61] For each of the Applicants major assets categories, for each year between 2015 to 2024, please provide the number of actual/forecast replacements.

RESPONSE:

	Actual/Forecast Replacements									
	Actual					Forecast				
Major Asset Categories	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Wood Poles	411	475	433	533	500	500	500	500	500	500
Pole-mount Transformers [1]	36	20	31	39	40	33	33	33	33	33
Pad-mount Transformers [1]	0	0	0	0	0	0	0	0	0	0
Capacitors	0	0	0	0	0	0	0	0	0	0
Station Power Transformers [2]	0	0	0	0	0	3	0	0	0	0
Spares and Voltage Regulating Transformers	0	0	0	0	0	0	0	0	0	0
Ratio Banks	0	0	0	0	0	0	0	0	0	0
Ground Grids	1	0	0	0	0	1	0	0	1	0
Substation Yards and Buildings [3]	1	0	0	0	0	1	0	0	1	0

Notes:

1. API does not have a program to replace distribution transformers, rather transformers are replaced proactively with other planned work (e.g. Line Rebuild, Voltage Conversion, etc.) or as a result of a failure.
2. The 3 station transformers identified for replacement in 2020 are 3 single-phase units making up a transformer bank in the Dubreuilville #2 Substation. No transformer replacement has been identified for the 2023 Bruce Mines DS project since the existing transformer may be suitable for relocation to the new substation based on age and condition.
3. Buildings included in this row of the table represent control buildings in substations, where applicable. Administrative and operation work centres are not included.

2-SEC-15

[Ex.2, DSP, p.73] The Applicant states: "API sustains its planning process through the lens of long-term (15-year), medium-term (5-year), and short-term (1-year) planning. Annual review of these plans allows the utility to prioritize investments and reach decisions regarding repair vs. replace, new-builds, or allow for reallocation of funding to higher priority investments. The long-term approach focuses on high-level reviews, such as system planning studies, in conjunction with load growth and voltage data to assure that the system will retain its level of access, reliability, and safety for the customer. Medium-term planning is driven by customer, municipal, First Nation, health, safety, environmental, regulatory, reliability, and other needs that API must service. The medium-term planning also allows for the incorporation of new information from short-term planning, as well as being used to review the effectiveness of maintenance programs to allow for adjustments as they may be required. Short-term planning addresses short-term needs, such as customer connection, or reaction to external events. The inputs to short term planning include current budget year projects, customer-driven asset development, municipal and developer asset development, and other short-term projects."

a. Please explain, using examples, how the Applicant undertakes its repair v. replacement analysis.
b. Please explain, using examples, how the Applicant determines when it will reallocate funding to higher priority projects.
c. What specific studies is the Applicant referencing that it uses for the purposes of 'long-term' planning. Please provide a copy of those studies.

RESPONSE:

a) API's inspection, testing and preventive/cyclical maintenance programs are extensively described in Section 4 of its Distribution Asset Management Plan, which is included as Appendix C to the DSP. Wherever the results of these activities indicate that corrective action (i.e. repair or replacement) is required, Operations staff will take one of the following actions:

   i. Immediate repair or replacement, using equipment and relatively low-cost stock materials that are readily available;
   ii. Scheduled repair or replacement, where non-stock materials and/or third-party equipment/labour resources are required;
   iii. Refer to Engineering for a more detailed repair vs. replacement analysis.

The third approach identified above is generally used for higher value assets such as substation transformers, ratio banks, protection and control equipment, voltage regulating equipment, and gang-operated switches. In most cases, Engineering confirms that the asset needing repair or replacement is required for the foreseeable future (i.e. there is no project in the near-term that would have otherwise replaced the asset that could be re-prioritized) and a repair approach is then undertaken, since repairs costs are often approximately an order of magnitude less that replacement costs.

A recent example where API pursued replacement instead of repair involves the Desbarats DS T1 power transformer failure. As discussed at page 56 of the DSP, immediately after the failure of the T1 power transformer at Desbarats DS, a system spare transformer was mobilized to restore power. Following this sequence of events, API evaluated the cost of repairing the failed T1 transformer, compared to the cost of procuring a replacement. API engaged a third party to perform testing on the failed T1 transformer to determine whether the unit was repairable. It was estimated that the repair would cost $173,500, while replacing the unit with one with the same specification would cost $240,856. API also considered the option of replacing the system spare that was used to replace the failed T1 transformer with a platform-mounted ratio bank installation that could improve its East of Sault Ste. Marie contingency response. This option was estimated at $250,000. API decided to proceed with the platform-mounted installation as it provided several additional advantages over the replace/repair options:

- API will leverage the ratio bank at its Bar River and Bruce Mines stations, improving the contingency and reliability of those stations;
- The type of installation has the flexibility of being located inside or outside the station;
- Mobilizing the transformers will not require specialized equipment (crane/float) – this aspect was particularly important since API determined that its contingency response to the Desbarats DS transformer failure would have been significantly delayed in the event that certain third-party equipment had not been immediately available; and,
- There will be reduced civil requirements at other substations to improve contingency response as compared to the repair/replace options.

b) An example of funding reallocation can be seen in API's planned vs. actual System Service spending for the 2015-2020 period, as shown in Section 4.3.1 of the DSP. The Hawk Junction DS Rebuild project was identified as a high-priority project due to load increases to the point where API's prior contingency plan of bypassing the single 44 kV voltage regulator could no longer provide adequate voltage levels. As the project progressed, it became clear that actual costs would exceed the original budget (see Section 4.2.3.1 of the DSP and the response to 2-VECC-5). At the same time as this station rebuild was considered, the results from a SCADA pilot project suggested that the long-term SCADA communications solution for API's service area should be re-evaluated (see Section 4.2.3.2 of the DSP). API therefore partially reallocated its 2015-2020 System Service spending to complete the higher priority Hawk Junction DS rebuild, and deferred the majority of its planned SCADA spending until a revised communication solution and implementation plan could be developed.

c) Please see the following studies and reports included as appendices to the DSP:
   i. Regional Planning Needs Assessment Report (DSP Appendix E);
   ii. API Planning Study Report (DSP Appendix K);

   Additionally, a number of other studies and reports included as appendices to the DSP incorporate long-term considerations and objectives (such as improving reliability, sustaining a least-cost vegetation management program, and meeting long-term facility needs) into the development of short to medium-term plans:
   i. Substation Strategic Plan (DSP Appendix D);
   ii. Reliability Study (DSP Appendix H);
   iii. SCADA Implementation Report (DSP Appendix I);
   iv. Vegetation Management Update (DSP Appendix L); and,
   v. Strategic Facility Planning (DSP Appendix M).

2-SEC-16

[Ex.2, DSP, p.82; Appendix 2-AB] Please provide a revised version of Appendix 2-AB, that excludes, a) all capital expenditures related to the work conducted/to be conducted in the Township of Dubreuilville that was previously Dubreuil Lumber Inc, b) the two proposed ACM projects.

RESPONSE:

A revised version of Appendix 2-AB is provided on the following page. Adjustments include:

- Removal of the Dubreuilville substation rebuild in 2020 ($1,245,949)
- Removal of the Echo River TS Project in 2021 ($7,500,000)
- Removal of the Sault Facility Project in 2022 ($14,118,000)
- Removal of other immaterial annual amounts in 2020-2024:
  - $17,600-$17,711 in customer-driven work form System Access
  - $11,947-$24,798 in small capital work from System Renewal

No adjustments were made to 2015-2019 values, since DLI-related costs for those years were not included in Appendix 2-AB. See Section 2.5.6 of Exhibit 2 for API’s proposed treatment of 2017-2019 capital investments in the Township of Dubreuilville.

Appendix 2-AB (For IRR 2-SEC-16; Exludes ACM and DLI)
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2020*

CATEGORY	Historical Period (previous plan1 & actual)															Forecast Period (planned)				
	2015			2016			2017			2018			2019			2020	2021	2022	2023	2024
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual2	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	1,020	963	-5.6%	1,020	992	-2.8%	1,020	883	-13.4%	1,020	960	-5.9%	1,020	913	-10.5%	886	945	912	888	888
System Renewal	4,044	3,809	-5.8%	4,834	4,229	-12.5%	4,834	3,434	-29.0%	4,834	4,971	2.8%	4,834	5,144	6.4%	4,494	4,685	4,808	6,481	4,604
System Service	1,232	3,033	146.2%	538	990	84.0%	5,088	192	-96.2%	538	339	-37.0%	538	868	61.4%	562	478	472	461	461
General Plant	2,679	3,084	15.1%	2,679	2,369	-11.6%	2,529	2,963	17.2%	2,029	3,240	59.7%	1,029	1,500	45.8%	1,357	1,238	1,290	1,178	1,098
TOTAL EXPENDITURE	8,975	10,889	21.3%	9,071	8,580	-5.4%	13,471	7,472	-44.5%	8,421	9,510	12.9%	7,421	8,425	13.5%	7,299	7,346	7,482	9,008	7,051
Capital Contributions	- 100	- 157	57.1%	- 100	27	-127.3%	- 100	- 137	36.5%	- 100	- 69	-30.7%	- 100	- 140	40.0%	- 102	- 100	- 100	- 100	- 100
Net Capital Expenditures	8,875	10,732	20.9%	8,971	8,607	-4.1%	13,371	7,336	-45.1%	8,321	9,441	13.5%	7,321	8,285	13.2%	7,197	7,246	7,382	8,908	6,951
System O&M (exclude Admin)	$ 6,761	$ 6,296	-6.9%	$ 6,897	$ 6,361	-7.8%	$ 7,035	$ 6,715	-4.5%	$ 7,175	$ 6,712	-6.5%	$ 7,319	$ 7,016	-4.1%	$ 7,080	$ 7,186	$ 7,294	$ 7,404	$ 7,515

2-SEC-17
[Ex. 2, DSP, p.82, 123] For each 2019 and 2020 material capital project, please provide the specific month the project is planned to go in-service. For projects in which the in-service date has changed since the filing of the application, please indicate the original in-service date.

RESPONSE:

The following tables provide the planned completion month for 2019 material capital projects. Detailed scheduling has not yet been completed for 2020 projects, therefore the in-service timing reflects the quarter in which API currently forecasts completing each project.

2019 Material Capital Projects	
Project	**Completion Month**
*Line Rebuild - Crawford St Bruce Mines	September
*Line Rebuild - HWY17 Wawa P1-P110	October
*Line Rebuild - Andrews to Mackay	November
*Line Rebuild - Mackay to Rabbit Blanket	November
*Line Rebuild - Hwy17N Step-up Xfmr to Mirian lake	November
*Line Rebuild - Hwy 552 East, Post Office Rd to Turmain Rd	September
*Line Rebuild - Hwy 17W of MacLennan Rd	September
*2018 Polecare PoleRepl - Phase 3 North of Sault	September
*2019 Pole Replacement (Various Locations)	December
No 4 Circuit feeder protection upgrade	September
Desb DS Upgrades	November
2020 Freightliner M2 106 RBD	December
Wawa workcenter - Transformer stand	July

(*) – Due to radial feeders, renewal projects have individual replaced assets coming into service on the same day as the installation date staggered over the duration of the project. Based upon customer scheduling (ie: MNR Prov Parks) projects could be broken into stages, with each stage separated by several weeks or months. Therefore, the dates above reflect the final completion of each project, but many assets may have been placed in service in prior months.

Category	Category Total Expenditure $'000	Program Name/Description	2020 $'000	Timing
System Access	**750**	Customer Connection & Service Upgrades	750	Monthly
System Renewal (*)	**5,618**	Line Rebuild – Havilland Shores Dr – Goulais (40 Poles)	300	4th Qtr
		Line Rebuild - 10th Side Rd – St. Joseph Island (40 Poles)	300	2nd Qtr
		Line Rebuild - Highway 17 - Agawa Bay (100 poles)	750	4th Qtr
		Line Rebuild - Highway 17 - North of Wawa (90 Poles)	675	3rd Qtr
		Line Rebuild - Highway 17 - South of Batchewana TS (20 Poles)	150	2nd Qtr
		Line Rebuild - Brickyard Rd - St. Joseph Island (37 Poles)	277.5	2nd Qtr
		Line Rebuild - Echo Lake Rd - Echo Bay (45 Poles)	337.5	2nd Qtr
		Express Feeder Rebuild - 34.5kV Desbarats to Bruce Mines (91 Poles)	912	4th Qtr
		Dubreuilville #2 DS Rebuild	1250	4th Qtr
		Small Capital	444	Monthly
		Storm Rebuild Capital	222	Monthly
System Service	**512**	Dubreuilville #2 DS – Reliability/Protection Upgrades	267	4th Qtr
		Installation of Capacitor Bank - Goulais/Batchewana Area	120	4th Qtr
		Feeder Protection Upgrades	125	3rd Qtr
General Plant	**1,253**	ROW Access Program	100	4th Qtr
		IT Hardware	227	4th Qtr
		Business Systems (SCADA, OMS, GIS, etc.)	132	4th Qtr
		Transportation and Work Equipment	662	4th Qtr
		Business Systems (SCADA, OMS, GIS, etc.)	132	4th Qtr

(*) – Due to radial feeders, renewal projects have individual replaced assets coming into service on the same day as the installation date staggered over the duration of the project. Based upon customer scheduling (ie: MNR Prov Parks) projects could be broken into stages, with each stage separated by several weeks or months. Therefore, the dates above reflect the final completion of each project, but many assets may have been placed in service in prior months.

2-SEC-18
[Ex.2, DSP, p.84] What specific assets are replaced in the Small Lines/Stations Capital program.

RESPONSE:

Assets includes items such as crossarms, insulators, hardware, fused cutouts, anchoring and guying components, grounding components, etc.

2-SEC-19
[Ex.2, DSP, p.87] With respect to the Echo River TS:

a. Please provide a copy of all internal business cases or similar documents outlining the cost, benefits, risks, options, etc. for the proposed Echo River TS project.
b. Please provide a detailed budget and schedule for the proposed project.
c. Please provide an explanation of the procumbent method that the Applicant will use for construction of the new TS.

RESPONSE:

a) Please see response to 2-VECC-16 and 2-Staff-21.

b) API only has preliminary budget and schedule information available at this time. Please see response to 2-VECC-16.

c) For clarity, the project involves the purchase and installation of a second transformer in an existing Hydro One substation. Hydro One will therefore be responsible for procurement and construction, and API will be required to make a capital contribution in accordance with the TSC.

2-SEC-20
[Ex.2, DSP, p.149] With respect to the Sault Facility Project:

a. Please provide a copy of all internal business cases or similar documents outlining the cost, benefits, risks, options, etc. for the proposed project.
b. Please provide a detailed budget and schedule for the proposed project.
c. With respect to your response to part (b), what is the basis for the estimate?
d. What is the annual cost of the lease of the current Sault St. Marie facility?
e. Has the Applicant had any discussions with Hydro One SSM/Hydro One Networks Inc. regarding sharing of jointly constructing a facility.
f. The evidence states: "API has leveraged a third-party consultant to assess options and costs
associated with extending the existing lease versus constructing a new facility". Please provide a copy of the assessment.
g. What is the proposed square footage of the new building and how much of that space will be allocated to administration versus operations?
h. Please provide the proposed design of the building and include any preliminary floor plans.
i. How many employees will be working out of the proposed facility.

RESPONSE:

a) Please refer to the response to 2-Staff-29(a).

b) Please refer to pages 6 & 7 of MGP's Master Facility Plan (MFP), included in the response to 2-Staff-29(a).

c) The estimate was prepared on behalf of API by its consultant MGP, after researching API's needs for a facility (through internal department meetings and cataloguing assets, etc) and applying industry standards and Ontario Building Code requirements to come up with a proposed layout of a new facility on the preferred development site, which was identified through the consultant's investigation of available properties and vetting those against requirement criteria for available land. Please refer to MGP's MFP report and API's Business Case document, filed in response to 2-Staff-29(a) for further information.

d) Total annual lease costs, including Rent, and API's share of Operating Costs and Municipal Taxes in accordance with the lease agreement, are as follows:
2015 - $615,150.44
2016 - $652,333.45

2017 - $658,204.63

2018 - $677,223.72

e) No – no such discussions have taken place. API *has* consulted with Hydro One regarding the theory of remaining at the Sackville location and co-existing on the facility footprint, however the concept of building a new shared facility has not been explored. Neither company has an appetite for such an arrangement due to the unique nature of their operations and the fact that there are very limited congruous activities that would promote such an arrangement.

f) Please refer to MGP's MFP report and API's Business Case document, filed in response to 2-Staff-29(a).

g) The new facility is proposed to be 41,703 square feet, including 13,676 square feet of Administrative space and 28,027 square feet of Operations space.

h) The conceptual footprint of the facility is included at pages 3-5 of MGP's MFP report, however the detail has not been created to the level of a floor plan design at this time.

i) 55 FTE employees will be working out of the proposed facility.

2-SEC-21
[Ex.2, DSP, p.118] Please explain how the Applicant prioritizes projects and asset replacements within programs.

RESPONSE:

Projects are prioritized according to API's asset management process outlined in Figure 3.1 (DSP, p.52). Prioritization within programs follows the same approach, with API considering the elements highlighted in the "Annual Budget Considerations".. As an example, for the Line rebuild program API considers not only the age profile of a given line, but also the impacts on reliability, customers, criticality of the line, etc.

2-SEC-22
[Ex.2, DSP, Appendix H] With respect to the SNC-Lavalin: *Reliability Study Report*, please provide the Applicant's response to each of the recommendations.

RESPONSE:

Recommendation # 1: Review of Vegetation Management Practices for Specific Areas

API intends to perform a review of its Vegetation Management Program to determine whether any modification to API's VM program is required (API completed this review through the engagement of a third-party, Ecological Solutions Inc., and has included it in Appendix L of the DSP.

Recommendation # 2: Increased API Coordination with Hydro-One

While API recognizes that potential opportunity to coordinate planned work with the Hydro-One, it is not always possible given timing restriction related to the work, the type of work being performed, etc. However, API continues to work closely with Hydro-One to ensure that we maximize any possible work coordination.

Recommendation # 3: Equipment Inspection/Replacement

API is taking steps to address outages resulting from porcelain switch failures, as described in response to 4-VECC-7. API is not intending on implementing any other proactive equipment replacement at this time, but will continue to track outages to determine if further programs are necessary.

Recommendation # 4: Feeder Automation

API recognizes that its express feeder systems do incur major impacts during outages (customer impacted and restoration time). As a result, API intends on implementing feeder automation on its express feeders East of the Sault (Feeder ER1 and ER2), as described in Section 4.4.5 of the DSP.

2-SEC-23

[Ex.2, DSP, Appendix J] With respect to the METSCO: *Asset Condition Assessment* Report:

a. [p.53-59] The Report makes several recommendations relating to asset condition data that the Applicant should collect. Please provide the Applicant's response to the recommendations its plan, if any, to collect the recommended data.
b. [p.60-64] The Report makes several recommendations relating to the number of assets that should be replaced between 2019 to 2024. For each of those asset categories, please provide a table that compares the number of assets the Applicant forecast to replace and the number recommended in the report.

RESPONSE:

a) Wood Poles: While API will not modify its inspection cycle related to wood poles, API will request this additional dataset be collected as part of the annual pole-testing program.

Overhead Primary Conductor: API does not intend to collect any additional data related to overhead primary conductors.

Underground and Submarine Primary Cable: Going forward, API intends on tracking the service age, outage records and loading history of its underground and submarine primary cables, but does not intend on performing any proactive testing at this time. Given the age and amount of in-service underground and submarine cable, API considers these assets a low risk at this time.

Distribution Transformer (Pole-mount and Pad-mount): While API does visually inspect these transformers during its annual line inspections, API historically was not recording data specific to the transformers. As a result, API intends on modifying its line inspection form such that the inspection notes will be recorded.

Overhead Switch: API maintains all its major overhead switches (typically three-phase gang operated switches) on a six-year cycle. Any deficiencies observed either through the visual inspection or through the manual operation of the device are corrected prior to the device being placed back into service. As such, API does not intend on collecting any further data for this asset class.

Reclosers – Oil Insulated: API maintains all its major oil-insulated reclosers on a six-year cycle, which includes removing the units from the field to perform mechanical and electrical testing, a detailed visual inspection and replacement of components as needed.

API intends to better record the results of this inspection and testing so that the data is available for subsequent asset condition assessments.

Reclosers – Vacuum Insulated: API maintains all its major vacuum-insulated reclosers on a six-year cycle, which includes removing the units from the field to perform mechanical and electrical testing, a detailed visual inspection and replacement of components as needed. API intends to better record the results of this inspection and testing so that the data is available for subsequent asset condition assessments.

Capacitors: API currently inspects its capacitors on a semi-annual frequency. API intends to better capture the results of the visual inspection and note specifically the components noted in METSCO's recommendation.

Substation Power Transformers: In addition to its current inspections and annual dissolved gas analysis, API intends to collect the dataset recommended for substation power transformers going forward.

Protection Relays: API intends to collect the dataset recommended for substation power transformers going forward.

b) Please refer to the following table:

		2019	2020	2021	2022	2023	2024
Wood Poles	METSCO recommendation (TUL 45 Yrs)	660	660	660	660	660	660
	METSCO recommendation (TUL 55 Yrs)	450	450	450	450	450	450
	API Planned	500	500	500	500	500	500
Distribution Transformers - Pole Mount	METSCO Recommendation	33	33	33	33	33	33
	API Planned	0	0	0	0	0	0
Distribution Transformers - Pad Mount	METSCO Recommendation	0	0	0	0	1	1
	API Planned	0	0	0	0	0	0
Overhead Switch	METSCO Recommendation	0	0	0	0	0	0
	API Planned	0	0	0	0	0	0
Reclosers	METSCO Recommendation	0	0	0	0	0	1
	API Planned	2	0	1	0	3	5
Capacitors	METSCO Recommendation	0	0	0	0	0	0
	API Planned	0	0	0	0	0	0
Power Transformers	METSCO Recommendation	0	0	0	0	0	0
	API Planned	0	3	0	0	0	0

2-SEC-24

[Ex.2, DSP, Appendix L] With respect to the Ecological Solutions Inc.: *Vegetation Management Update* Report:

a. Please provide a copy of the 2014 report.
b. For each recommendation that has not been fully implemented, please explain why not.

RESPONSE:

a) The 2014 report has been filed as “API_IRR_2-SEC-24_2014 VM Report.pdf”.
b) For each of the recommendation not fully implemented please see the updates below:

Recommendation 12-2

Establishment of cycles required to deliver a sustainable, least cost VM program.

Since the 2014 study, API has made significant efforts to complete its Right of Way (ROW) Expansion and ROW Hardening Programs. With completion of these program API’s current program is on track to implement the recommended cycles starting in 2020.

Recommendation 12-9

Collect field data in more detail.

API has implemented a customized software solution that will provide the capability to collect detailed information as recommended. API has been testing and piloting this effort in 2019 with the intent to be fully implemented to capture the work units in 2020.

3-SEC-25
[Ex.3, Appendix 2-H] Please provide a revised version of Appendix 2-H with an additional column showing year-to-date actuals.

RESPONSE:

See 3-VECC-24 for Other Revenue breakdown provided for June 2019 year-to-date actuals.

4-SEC-26

[Ex.4, Appendix 2-JC] Please provide a revised version of Appendix 2-JC with an additional column showing year-to-date actuals.

RESPONSE:

See table below.

Programs	Last Rebasing Year (2015 Board-Approved)	Last Rebasing Year (2015 Actuals)	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year	Variance (Test Year vs. 2018 Actuals)	Variance (Test Year vs. Last Rebasing Year (2015 Board-	2019 Jun YTD Actuals
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Customer Focus										
Customer Service, Mailing Costs, Billing and Collections, LEAP	908,819	809,242	728,128	721,552	779,344	849,591	848,296	68,951	-60,523	413,873
Community Relations	22,102	24,430	32,308	47,552	141,890	94,552	96,558	-45,332	74,456	-10,951
Bad Debts	100,000	64,251	62,004	49,190	43,555	71,000	71,000	27,445	-29,000	-4,414
Meter Reading	106,363	115,582	117,111	131,602	124,976	77,735	104,058	-20,918	-2,305	65,786
								0	0	
								0	0	
Sub-Total	1,137,284	1,013,505	939,551	949,897	1,089,765	1,092,879	1,119,912	30,147	-17,372	464,294
Operational Effectiveness										
Stations	329,020	243,664	169,781	141,119	198,821	190,271	201,225	2,404	-127,795	99,054
Load Dispatching	106,000	39,766	40,668	127,237	135,356	157,587	165,702	30,346	59,702	63,186
Supervision and Engineering	209,996	196,955	166,716	206,344	281,939	300,320	246,582	-35,357	36,586	133,044
Meters Maintenance	839,470	755,168	776,309	835,155	752,357	844,549	846,103	93,746	6,633	412,196
Overhead Lines and Feeders	1,287,589	1,202,398	1,307,560	1,425,626	1,157,007	1,258,908	1,321,533	164,526	33,944	527,694
Distribution Transformers	27,197	16,045	10,937	2,776	3,520	15,413	17,446	13,926	-9,751	0
Right of Way Maintenance Program	3,301,180	3,231,088	3,346,741	3,409,082	3,616,124	3,578,067	3,571,764	-44,360	270,584	1,282,201
Underground Lines, Feeders, and Services	37,102	13,552	2,964	9,927	10,293	12,530	14,466	4,173	-22,636	11,923
Poles Towers & Fixtures	174,034	127,827	150,750	121,217	101,801	129,056	130,195	28,395	-43,839	47,770
Salaries, Wages and Benefits for Administrative Services	2,484,276	2,704,652	2,521,175	2,621,314	2,510,807	2,966,460	3,080,168	569,361	595,892	1,455,620
Other External Administrative Services	478,490	398,334	629,516	507,229	512,310	434,790	441,194	-71,116	-37,296	204,578
Rent and Maintenance of General Plant	869,183	836,940	858,254	868,096	886,554	903,530	1,287,715	401,161	418,532	475,550
Other Operating and Maintenance	449,758	469,965	389,061	436,901	454,422	529,601	565,230	110,808	115,472	289,376
Other General and Admin	358,416	324,708	295,860	314,599	292,394	358,915	361,170	68,776	2,754	148,382
								0	0	
Sub-Total	10,951,711	10,561,062	10,666,290	11,026,620	10,913,705	11,679,996	12,250,493	1,336,788	1,298,782	5,150,575
Public and Regulatory Responsiveness										
Regulatory & Compliance	215,886	240,992	198,062	155,204	131,127	151,580	306,783	175,656	90,897	62,877
								0	0	
								0	0	
								0	0	
								0	0	
Miscellaneous								0	0	
Total	**12,304,881**	**11,815,559**	**11,803,904**	**12,131,721**	**12,134,596**	**12,924,455**	**13,677,187**	**1,542,591**	**1,372,306**	**5,677,746**

4-SEC-27
[Ex.4, p.41] With respect to lease costs:

a. Please provide an update on the status of negotiations of the Sault Ste. Marie Facility lease.
b. Please provide the total amount spent or forecast to be spent on the lease of the Sault Ste. Marie Facility for each year between 2015 to 2020.

RESPONSE:

a) API has not signed a new lease. API is currently in discussion with Hydro One regarding a sublease consistent with the terms of the head lease. Hydro One is currently negotiating a short term lease (head lease) with Brookfield. All parties are targeting a new short term lease to be finalized before the expiry of the current lease.

b) The total annual lease costs for 2015-2018, including Rent, and API's share of Operating Costs and Municipal Taxes in accordance with the lease agreement, are as follows:

2015 - $615,150.44

2016 - $652,333.45

2017 - $658,204.63

2018 - $677,223.72

The forecast spending for lease costs in 2019 is $755,092.80.

For the forecast of 2020 lease costs, API is currently working with the landlord to establish a new lease. Please refer to page 29 of Exhibit 4 for API's projection of increased costs associated with a new lease agreement for 2020.

4-SEC-28

[Ex.4, p.47] The evidence states that the current collective agreement with the PWU ends at the end of 2019. For the purposes of the 2020 test year budget, what assumptions is the Applicant making regarding the new collective agreement?

RESPONSE:

Please refer to response provided in 4-Staff-56.

4-SEC-29

[Ex.4, p.49] Please revise Appendix 2-K to:

a. Add an additional column to show 2019 year-to-date actuals.
b. Add two rows to show the annual amount of total compensation allocated to OM&A and Capital.

RESPONSE:

a) See table below.

b) See table below.

Appendix 2-K
Employee Costs

	Last Rebasing Year (2015 Board Approved)	Last Rebasing Year (2015 Board Approved Restated)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year	2019 Jun YTD Actuals
Number of Employees (FTEs including Part-Time)[1]									
Management (including executive)	15	15	12	11	10	11	11	11	11
Non-Management (union and non-union)	66	59	59	59	59	58	60	59	57
Total	81	74	71	70	69	69	71	70	68
Total Salary and Wages including ovetime and incentive pay									
Management (including executive)	$ 1,663,095	$ 1,663,095	$ 1,593,050	$ 1,527,913	$ 1,365,026	$ 1,464,209	$ 1,560,527	$ 1,608,679	$ 771,076
Non-Management (union and non-union)	$ 4,722,845	$ 4,722,845	$ 5,066,718	$ 5,078,369	$ 5,090,533	$ 5,427,381	$ 5,671,376	$ 5,843,490	$ 2,619,726
Total	$ 6,385,940	$ 6,385,940	$ 6,659,768	$ 6,606,283	$ 6,455,559	$ 6,891,590	$ 7,231,903	$ 7,452,169	$ 3,390,802
Total Benefits (Current + Accrued)									
Management (including executive)	$ 645,642	$ 645,642	$ 446,204	$ 359,625	$ 358,614	$ 388,910	$ 403,538	$ 367,350	$ 193,056
Non-Management (union and non-union)	$ 2,112,645	$ 2,112,645	$ 2,106,901	$ 1,687,039	$ 1,888,383	$ 1,966,521	$ 2,080,049	$ 1,760,359	$ 851,536
Total	$ 2,758,287	$ 2,758,287	$ 2,553,105	$ 2,046,664	$ 2,246,996	$ 2,355,431	$ 2,483,587	$ 2,127,710	$ 1,044,592
Total Compensation (Salary, Wages, & Benefits)									
Management (including executive)	$ 2,308,737	$ 2,308,737	$ 2,039,254	$ 1,887,539	$ 1,723,640	$ 1,853,120	$ 1,964,065	$ 1,976,029	$ 964,132
Non-Management (union and non-union)	$ 6,835,490	$ 6,835,490	$ 7,173,619	$ 6,765,408	$ 6,978,916	$ 7,393,902	$ 7,751,424	$ 7,603,850	$ 3,471,262
Total	$ 9,144,227	$ 9,144,227	$ 9,212,873	$ 8,652,947	$ 8,702,556	$ 9,247,021	$ 9,715,489	$ 9,579,879	$ 4,435,394

Note:

[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

Allocated to OM&A	$ 6,776,828	$ 6,776,828	$ 6,316,206	$ 5,567,697	$ 6,082,224	$ 5,836,322	$ 6,936,778	$ 6,811,772	$ 3,312,197
Allocated to Capital	$ 2,367,399	$ 2,367,399	$ 2,896,667	$ 3,085,250	$ 2,620,332	$ 3,410,699	$ 2,778,711	$ 2,768,107	$ 1,123,197
Total	$ 9,144,227	$ 9,144,227	$ 9,212,873	$ 8,652,947	$ 8,702,556	$ 9,247,021	$ 9,715,489	$ 9,579,879	$ 4,435,394

4-SEC-30
[Ex.4, p.57] Please provide a copy of the referenced BDR Report filed in the EB-2016-0061 proceeding.

RESPONSE:

This has been provided in 4-Staff-47.

4-SEC-31
[Ex.4, p.73] Please confirm that no one-time regulatory costs that the Applicant seeks to recover beginning in 2020 on an amortized basis are also included in any 2015 to 2019 costs contained in Appendix 2-JA, JB or JC. If so, please remove the costs from those years, and revise the appendices.

RESPONSE:

Confirmed; there is no overlap between the one-time regulatory costs to be recovered beginning in 2020 and any of the amounts included in Appendix 2-JA, JB or JC for 2015 to 2019. See response to 4-VECC-31 for additional detail.

4-SEC-32
[Ex.4, p.73] Please provide a detailed breakdown of the costs included in the Recovery of Transaction and Integration Deferral Account.

RESPONSE:

Please refer to 4-Staff-57.

4-SEC-33
[Ex.4, p.85] Please revise the PILS information to account for the passing of Bill C-97, the Federal Budget implementation legislation. Please explain any changes made.

RESPONSE:

Any applicable changes have been explained and have been incorporated in the revised PILs model submitted in response to 4-Staff-58.

4-SEC-34

[Ex.4, Appendix 4A] The Applicant filed a letter from Korn Ferry providing an estimate of base salary increases for 2020.

a. What base salaries are Korn Ferry providing an estimate increase to?
b. How does the Applicant actually determine the increase to base salaries?

RESPONSE:

a) The base salaries Korn Ferry provided an estimate for were the executive, management, non-union and union salary increases in the application.

b) Union salaries are negotiated and agreed to during the collective bargaining process. For management and non-union positions, salary increases are based on market information provided annually by Korn Ferry. Salaries are adjusted accordingly based on this recommendation and individual performance.

7-SEC-35

[Ex.7, p.7; EB-2018-0271 Decision and Order, p.24] The Board stated in its Decision in EB-2018-0271: "However, the OEB agrees with Algoma that its approach to integrating Dubreuil costs into Algoma's revenue requirement should be done in a manner that ensures there is no harm to Algoma's existing customers." Please demonstrate that under a scenario that the Applicant had not acquired and integrated the former Dubreuil Lumber Inc distribution system, rates for its customers in 2020 would be no higher than those proposed rates in this application. Please provide all supporting calculations.

RESPONSE:

For the majority of API's customers in the RRRP-eligible rate classes, distribution rates are adjusted annually based on the OEB-approved RRRP adjustment factor, as described on page 6 of Exhibit 8. The RRRP methodology for calculating the RRRP adjustment factor is set by regulation, and is therefore not impacted in any way by the acquisition and integration of the former DLI distribution system. It therefore follows that there is no rate impact or bill impact for these customers relating to the acquisition.

To ensure no harm to the Seasonal and Street Lighting rate classes, which are not eligible for RRRP, API proposed to directly allocate costs associated with the DLI distribution system to certain rate classes in the cost allocation model, based on the proportion of customers and load in each rate class for the former DLI customers.

As shown on page 9 of Exhibit 7, all of the acquired customers are either R1 or Street Light customers. Since there are no Seasonal customers being acquired, none of the costs related to DLI are allocated to API's Seasonal customer class, and there is therefore no rate or bill impact to Seasonal Customers.

Finally, the impact to the Street Lighting rate class can be determined by comparing the incremental revenue that will result when API begins billing the street lights in Dubreuilville in 2020 to the DLI related costs that are allocated to the Street Lighting class in the cost allocation model. The table on the following page shows that there is a net benefit to the Street Lighting class.

	2020 Rate	**Connections/Load**	**2020 Revenue**
Fixed Revenue	$1.31	50	$786
Variable Revenue	$0.3237	26,651	$8,627
Total Revenue			*$9,413*
DLI-related costs allocated to Street Lighting Rate Class: (Cost Allocation Model; Sheet I9; Cell K153)			*$1,988*
Net Benefit to Street Lighting Rate Class:			**$7,425**

9-SEC-36

[Ex. 9, p.11] Please confirm that in this application, the Applicant is not seeking approval and disposition of the balances of any deferral and variance accounts related to its activities regarding the operation and acquisition of the Dubreuil Lumber Inc distribution system.

RESPONSE:

Not confirmed. Please see response to 9-VECC-48(a).

1.0 ADMINISTRATION (EXHIBIT 1)

1.0-VECC-1

Reference: Exhibit 1, page 32

a) Please explain the purpose of the holding 1228158 Ontario Limited by Algoma Power Inc.

RESPONSE:

a) The sole purpose of the numbered company is the ownership of a right of way permit related to an API asset on a specific First Nation reserve.

1.0-VECC-2

Reference: Exhibit 1, page 62 / Appendix B

a) Please provide the total cost of customer engagement activity undertaken in support of this application. Please provide this cost in two parts: (1) internal utility costs and (2) external consulting and other costs.

b) In what years were these costs incurred?

c) Was the AIM insight report completed by internal staff or by external consultants (Utility Pulse)? If the latter please provide the cost of that exercise/report.

RESPONSE:

a) Please see a breakdown of costs, both internal and external related to customer engagement activities in support of the application:

	2017	**2018**	**2019**	
Internal Utility	2,300	25,223	13,114	
External Consulting				
Annual Phone Survey		25,250		
AIM Program		18,421	34,350	
Total	2,300	68,894	47,464	**$ 118,658**

b) Please see above for cost allocation by year.

c) The AIM program was completed as a collaboration between internal staff and the consultant. See part a) for the cost of the AIM program, which includes the production of the final report.

API notes that only the external consulting amount of $34,350 in 2019 is recorded as a one-time regulatory cost. All other costs in the above table were treated as regular OM&A expense.

API further notes that the annual phone survey was included in the above table because the 2018 version of the survey incorporated supplemental questions in coordination with the Taking AIM program in support of application-specific engagement. Similar annual phone surveys for other years are not included since the content was not specific to the current application.

1.0-VECC-3

Reference: Exhibit 1, Appendix A (PDF 124)

a) Please update the scorecard results to provide the 2018 actual results.

RESPONSE:

a) Please see attached.

Scorecard - Algoma Power Inc.

8/14/2019

Performance Outcomes	Performance Categories	Measures		2014	2015	2016	2017	2018	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		100.00%	100.00%	99.40%	99.24%	98.63%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		82.60%	81.90%	86.60%	80.06%	86.06%		65.00%	
	Customer Satisfaction	First Contact Resolution		99.76%	99.74%	99.97%	99.96%	99.97%			
		Billing Accuracy		99.88%	99.85%	99.85%	99.48%	99.86%		98.00%	
		Customer Satisfaction Survey Results		69%	92%	79%	88%	93%			
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%	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]		7.96	8.80	5.46	7.68	7.51			10.62
		Average Number of Times that Power to a Customer is Interrupted [2]		3.24	3.68	2.57	3.95	2.20			4.46
	Asset Management	Distribution System Plan Implementation Progress		In Progress	Completed	Completed	In Progress	Completed			
	Cost Control	Efficiency Assessment		5	5	5	5	5			
		Total Cost per Customer [3]		$1,980	$2,107	$2,126	$2,116	$2,182			
		Total Cost per Km of Line [3]		$12,483	$13,306	$13,453	$13,408	$13,831			
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%	74.00%			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		100.00%	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)		2.33	1.14	1.10	0.37	1.07			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.22	1.12	1.02	1.17	1.42			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.85%	9.30%	9.30%	9.30%	9.30%			
			Achieved	8.38%	11.07%	9.89%	8.11%	8.22%			

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.

2.0 RATE BASE (EXHIBIT 2)

2.0-VECC -4
Reference: Exhibit 2, page 37, Table 14 & Appendix 2A-DSP pg. 23

a) In a number of places API notes that it has or is expects overhead conductors to exceed the life of its poles (see, for example DSP, pg.75). Yet the service life for this category of asset chosen by API is below the Kinectrics band (45 years rather than 50-60 years). Please explain this apparent discrepancy.

RESPONSE:

a) At the time of setting a 45-year depreciation rate for conductor, API had been replacing conductor along with poles for the vast majority of its line rebuild projects, and the service lives were therefore set equal for poles and conductors.

Cases of replacing larger quantities of poles without conductor replacement is a relatively new trend, and this practice is also not applied to all of API's pole replacement projects. API does not have age information on the conductors that have been left in place during recent pole replacement projects and based the decisions on assessment of condition only (based on visual inspection and sample testing). As such, the re-use of existing conductor may end up being a short-term trend based on the condition of certain vintages and sizes of conductor.

For those conductors that have been recently left in place, discussions of a run-to-failure strategy such as at p.75 of the DSP, are intended to reflect API's expectation that in most cases, conductor condition will not be the driver of future line rebuild project. API does however expect that in most cases going forward, these conductors would be replaced at the same time as future pole replacement because that is the most cost-effective way to proceed.

2.0-VECC-5
Reference: EB-2014-0055 Exhibit 2, Appendix A DSP, page 55 & Exhibit 2, page 34, Table 12 System Service variances

a) The EB-2014-0055 DSP showed the Hawke Junction DS Rebuild/Expansion as costing $997,000. In the event, the project costs were $3,576,098 ($2,805,052 + 771,046) or a difference of $2,579,098.

The following list summarizes the main drivers of approximately $1.7 million in cost increases, in relation to the descriptions provided above:

- $535k – Inability to include preliminary cost saving strategies during detailed design
- $220k – Increased excavation depth resulting from geotechnical report
- $293k – Refinement of preliminary design assumptions during detailed design
- $375k – Line rebuild and SCADA-capable reclosers budgeted in other DSP categories
- $238k – Competitive bid costs higher than engineering estimates adjusted for final design

This explains $1,661,000 of the overspending from the original estimate. What accounts for the remaining $918,098 in spending above the original estimate?

RESPONSE:

a) In addition to the budgeted amounts shown above of $997,000, OEB Appendix 2-AA from EB-2014-0055 identified $693,404 in forecasted 2014 bridge year spending for this same project. The budgeted amount should be further adjusted to include actual 2013 spending of $35,728 for early engineering which was included in 2014 CWIP. This results in a total original estimate of $1,726,132 that was included in the 2015 application.

In addition to the actual 2015 and 2016 costs of $3,576,098 identified above, 2013 and 2014 actual costs totaled $257,807, for a total 2013-2016 cost of $3,833,907, the total variance is therefore $2,107,773 ($3,833,907 - $1,726,132).

Of the $2,107,773 difference material variances totaling $1,661,000 are explained in the reference above, leaving $446,773 in spending above the original estimate. This amount relates to several items less than API's materiality threshold, as detailed in the following table:

Category	Explanation	Amount
Decommissioning of original station site	At the time of budgeting the original project, API expected to install a third voltage regulator in this site in the near future related to a system expansion to accommodate a new large industrial customer. This never materialized, requiring the original station site to be decommissioned.	$121,625
Contractor change orders during construction	Approx. 5% of total contract value, which is typical for this type of project.	$119,329
API Lines Labour	Efforts relating to installation of major material, 44 kV bypass line, switching for planned outages, etc. exceeded the original estimate.	$81,150
Increased land acquisition costs	Purchasing the required property was more expensive than originally estimated.	$48,443
Project Management and Engineering	Efforts relating to project management, contract administration, land acquisition, records and commissioning exceeded the original estimate.	$43,430
Tree Clearing	The final size and orientation of the new substation required tree clearing that was not included in the original estimate.	$17,500
Miscellaneous		$15,296
Total		**$446,773**

2.0-VECC -6
Reference: Exhibit 2, pages 48

a) Are the 34 Mist Meters to be installed in 2019 included as part of API's capital expenditure budget/forecast for 2019 (i.e. included as part of projects in Appendix 2-AA)?

RESPONSE:

a) The 34 Mist Meters to be installed are not included as a material project in Appendix 2-AA. Given the small number of meters, API expects that the total costs will be immaterial and will be managed in the miscellaneous System Access budget.

2.0-VECC -7
Reference: Appendix 2A-DSP pg. 39 / Appendix H – API Reliability Study

a) API experienced a large increase in outages due to defective equipment in 2018. There also does not appear to be an improving trend in this category of outages. Has API identified any particular equipment issues (e.g. porcelain insulators, transformers etc.) that are the primary cause of equipment failure outages? If yes, what program(s) are being proposed for the rate period to try to reduce this type of outage?

RESPONSE:

As discussed at page 64 of the DSP, porcelain switches have been identified as a significant contributor to the equipment failure category. API has implemented a program to proactively replace these switches in conjunction with other planned work, with the goal of preventing outages and reactive replacement. All porcelain switches are replaced with polymer versions during any planned line projects. Also, line crews will replace porcelain switches in the general vicinity in cases where they are mobilized for smaller routine work orders such as service connections or upgrades.

Given the geographically dispersed nature of API's distribution network, combining the replacements with other planned work allows for cost-effective replacement over time as compared to a program solely focused on switch replacement.

2.0-VECC -8
Reference: Exhibit 2, page 17

	Includes outages caused by loss of supply					Excludes outages caused by loss of supply					Excluding Major Event Days				
Index	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018
SAIDI	12.31	19.17	6.22	15.90	13.83	10.12	16.94	5.46	11.10	11.96	8.68	11.03	6.22	12.20	9.38
SAIFI	6.47	7.12	3.85	5.97	4.26	4.04	4.40	2.57	4.26	3.14	4.93	6.39	3.85	5.15	3.31

a) Please clarify Table 26 (reproduced above). Does the third category (Excluding Major Event Days - MEDs) also exclude outages due to loss of supply? If not please provide a table showing SAIDI/SAIFI without both loss of supply and MEDs.

b) Does API have any specific initiatives in the DSP or other business plans to reduce the duration of outages? If yes please explain if these are new initiatives and if there is any incremental cost associated with the initiative(s).

RESPONSE:

a) No. The third category (Excluding Major Event Days – MEDs) reflects all outages with only MEDs removed from the total. Table 27 at the above reference provides SAIDI/SAIFI without both loss of supply and MEDs.

b) API has a number of strategies related to reducing the response time and overall outage duration. Namely,

   a. Installing fault indicators at strategic locations with the goal of quicker fault location identification and reduced the patrol time
   b. Tracking weather patterns and notifying crews ahead of major weather events
   c. Installing additional SCADA-capable devices on API's East of Sault 34.5kV system, ultimately creating a looped ring bus configuration with distribution automation capability.

2.0-VECC -9
Reference: Exhibit 2, Appendix 2A-DSP pg. 45

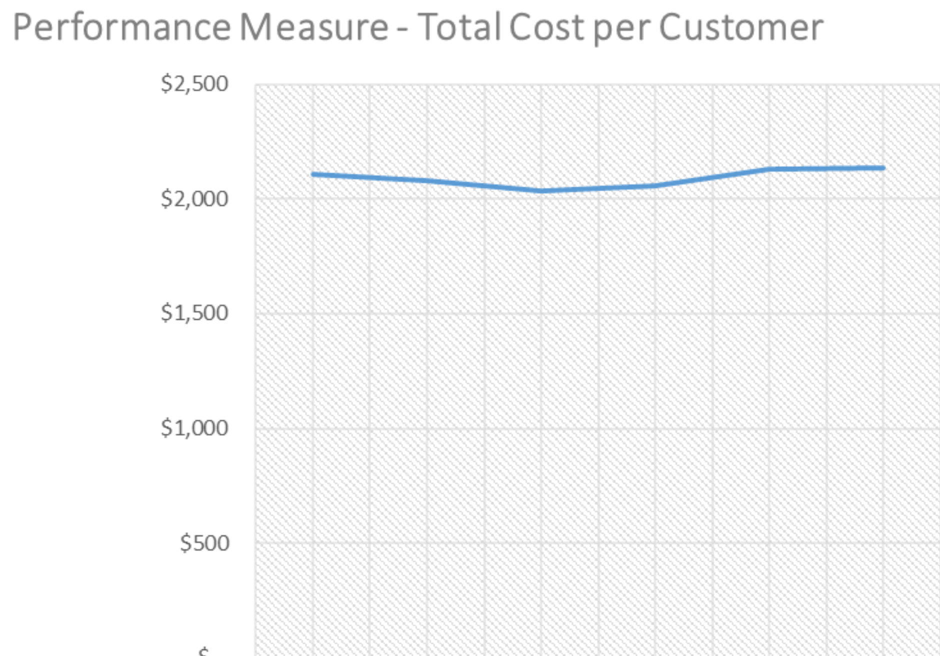
a) Are Figures 2.15, 2.16 and 2.17 (Performance Measures) shown in actual (nominal) dollars or constant (real) dollars? If the former please recast the figures to show the performance measures in constant dollars over the 2015 to 2019 period.

RESPONSE:

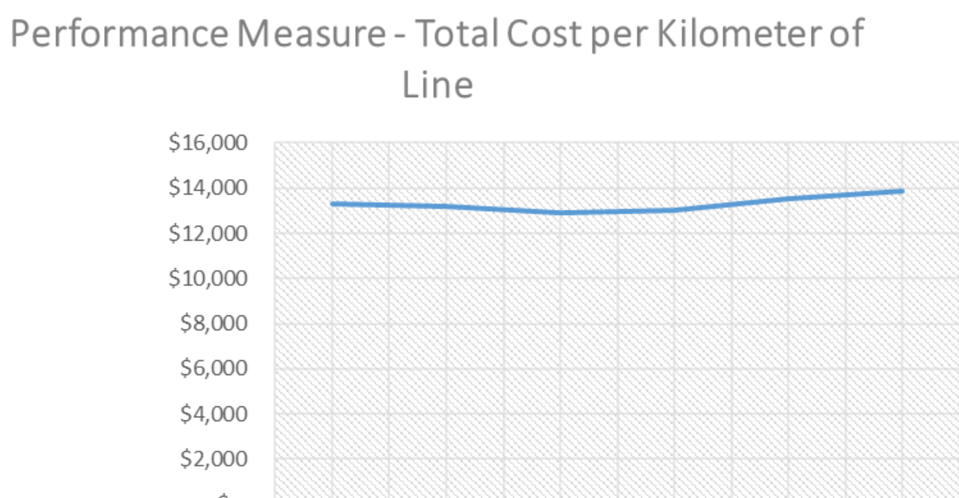
a) These figures show actual dollars, consistent with the values presented on the OEB Scorecard. The figures have been adjusted to 2015 constant dollars, using the following adjustment factors, with 2020 set equal to 2019 since the OEB has not yet published an inflation factor for 2020 applications:

	2016	**2017**	**2018**	**2019**	**2020**
OEB Inflation Factor for IRM	2.10%	1.90%	1.20%	1.50%	1.50%
Compound Inflation	2.10%	4.04%	5.29%	6.87%	8.47%
Adjustment Factor (1 / Compound Inflation)	97.94%	96.12%	94.98%	93.57%	92.19%

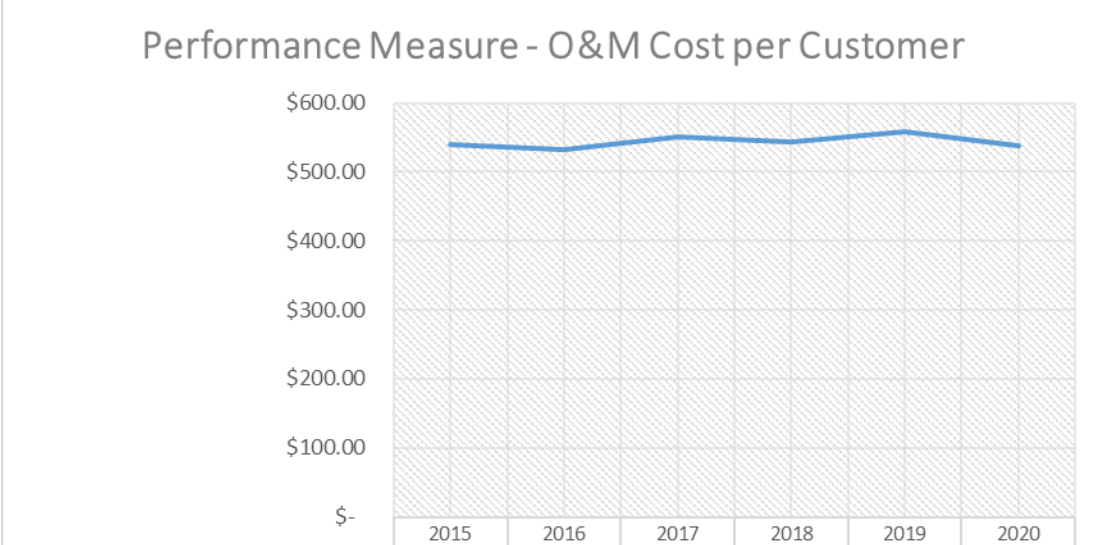
The resulting updated cost performance graphs in 2015 constant dollars are as follows:



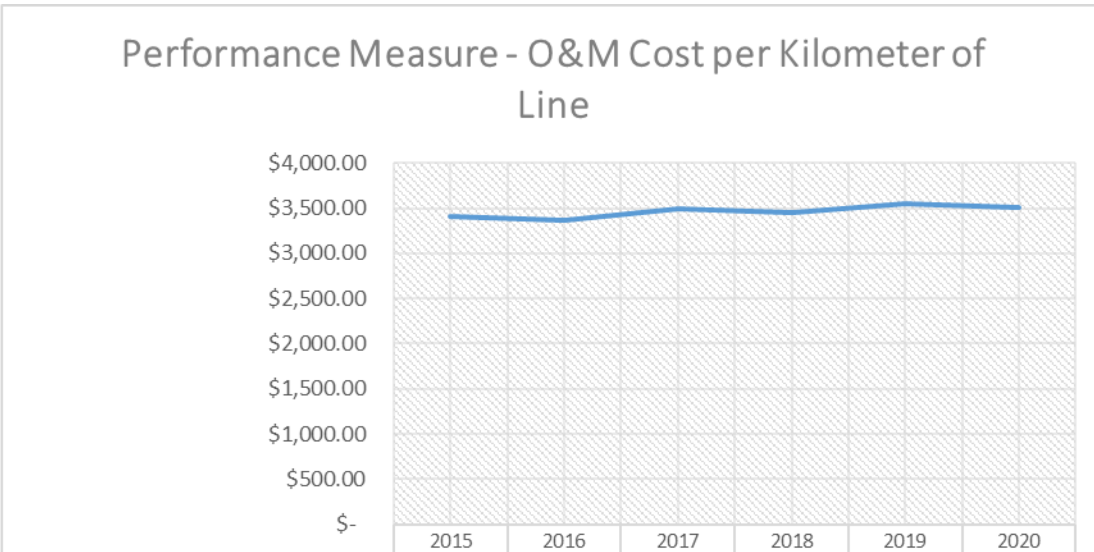
	2015	2016	2017	2018	2019	2020
Performance Measure - Total Cost per Customer	$2,107	$2,082	$2,034	$2,057	$2,130	$2,134



	2015	2016	2017	2018	2019	2020
Performance Measure - Total Cost per Kilometer of Line	$13,306	$13,177	$12,887	$13,042	$13,526	$13,897



	2015	2016	2017	2018	2019	2020
Performance Measure - O&M Cost per Customer	$539.17	$532.22	$550.55	$543.76	$559.19	$538.60



	2015	2016	2017	2018	2019	2020
Performance Measure - O&M Cost per Kilometer of Line	$3,405.32	$3,367.92	$3,488.99	$3,447.56	$3,550.79	$3,507.43

2.0-VECC-10

Reference: Exhibit 2, Appendix 2-A, DSP

a) Federal Government PCB regulations require the testing of electrical equipment and elimination of PCBs in equipment by the end of 2025. Please outline the program API is implementing during the rate period to achieve this requirement. Please show the spending per year from 2009 to 2024 on the program.

RESPONSE:

a) API's approach since 2007 has been to replace equipment containing PCB's above the regulatory thresholds (mostly pole-top transformers with PCB concentrations greater than or equal to 50mg/kg) in conjunction with other planned projects. For example, during line rebuild projects driven by pole and/or conductor replacement needs, or during system voltage conversion efforts, API has replaced any PCB-contaminated transformers instead of transferring the contaminated transformer to a new pole. Following this approach, API had substantially replaced the required equipment by 2014, and subsequently undertook a focused program for the small number of remaining transformers with PCB concentrations above 50 mg/kg in 2015 and 2016. 2015 and 2016 costs are shown in the table below. Since PCB equipment replacements in other years were completed in conjunction with other planned work, API has not separately tracked costs specific to PCB replacement. Please see the response to 4-Staff-57 for details of PCB transformer testing and replacement in Dubreuilville in 2019.

	2015	**2016**
PCB Program	$45,545	$38,954

2.0-VECC-11

Reference: Exhibit 2, Appendix 2-A, DSP, pg.79

a) What was the average age of each category of fleet vehicles (as listed in the DSP but excluding trailers and ancillary vehicles) at the end of 2018 and what will be the expected average age at the end of 2020?

- 12 aerial devices (bucket trucks, radial boom derricks)
- 19 pickup trucks
- 1 AWD Crossover
- 8 snowmobiles
- 5 off-road vehicles

RESPONSE:

a) The average ages are provided in the following table:

Average age at end of	**2018**	**2020**
12 aerial devices (bucket trucks, radial boom derricks)	5.4	5
19 pickup trucks	4	3.7
1 AWD Crossover	1	3
8 snowmobiles	5.9	7.9
5 off-road vehicles	4.6	4

2.0-VECC -12
Reference: Exhibit 2, Appendix 2A-DSP pg. 83

Table 4-1: System Access Capital Investments ($,000)

Capital Investments	2020	2021	2022	2023	2024
Customer Demand Work (New Connections and Service Upgrades)	$750	$780	$780	$780	$780
Total of Items Less Than Materiality (New Transformers/Meters, Plant Relocations)	$153	$184	$151	$127	$127
System Access Total	**$903**	**$963**	**$930**	**$906**	**$906**

a) Please provide the forecast contributions for each year 2020 through 2024. Please explain how the forecast contributions are estimated.

b) Do any of the categories of capital spending other than System Access attract capital contributions? If so please provide the expected contributions for each category with capital contributions.

RESPONSE:

a) API has included the forecasted contributions in Table 9 of Exhibit 2, as well as in Appendix 2-AB. The forecasted contributions are estimated based on annual rolling averages from the previous 5 years.

b) No, the capital contribution is required for customer and third-party work, which is all contained with the System Access category.

2.0-VECC -13

Reference: Exhibit 2, Appendix 2A-DSP pg. 89 & 145-

> In an effort to properly organize and manage important records and documents, API will be investigating its record-producing processes and evaluating the benefits of the implementation of an Electronic Document and Record Management System (**EDRMS**)

a) Please provide the forecast cost and year of implementation of this program.

b) Please explain why the IT hardware costs in 2020 are significantly higher than in any of the prior 5 years.

RESPONSE:

a) As discussed on page 8 of API's DSP: "The process of developing an EDRMS would be initiated with a process review, project description and product investigation by the end of 2020. A cost-benefit analysis to be completed in the future will confirm if further investment in better document and record management processes and an associated EDRMS will be worthwhile."

b) There are various communication and computer systems at the API office which are on a 5-year replacement cycle. In 2020, the solid-state hard disk storage arrays and supporting servers are up for replacement, at a cost of approximately $107k.

2.0-VECC -14
Reference: Exhibit 2, Appendix 2A-DSP pg. 116

a) Please provide an update as to the current status and costs of the Desbarats work centre and associated transformer stand project. What is the current estimated completion date of this project?

b) Please explain what remaining work is being completed at the Wawa Work Centre. Please provide the current estimated 2019 costs for work at this location and the forecast costs for 2020.

RESPONSE:

a) The Desbarats Workcentre project was completed in November of 2018 (as stated on page 116 of DSP). The total cost for that project was $930,000.

The transformer stand project will be released for tender by August 15, 2019, with an estimated completion date of November 30, 2019. Costs-to-date for this project are minimal. The estimated cost of the construction and installation of the stand is approximately $110,000.

b) Final installation of the second transformer stand (which was placed on a temporary platform in December of 2018 due to ground conditions prohibiting the designed permanent installation from being completed) was completed in July of 2019, at a cost of $10,000. Additionally, the second half of the Stores Addition was completed in February of 2019. 2019 costs attributed to that project amounted to $117,000.

Current estimated 2019 and 2020 costs are consistent with the amounts shown in Appendix 2-AA, which reflect completion of the projects discussed above, and a small annual budget for immaterial purchases/investments.

2.0-VECC-15

Reference: Exhibit 2, Appendix I – SCADA Deployment Plan

a) Among the consultant's recommendation are:

> API should review its overall needs for operational communication infrastructure for voice, SCADA, AMI, and operational applications. There are likely opportunities for sharing facilities for backhaul communication between Sault Ste Marie and major outlying areas. <u>A detailed long term communication plan for SCADA should be completed with consideration of other API operational communication needs.</u> (Emphasis added)

Has API undertaken such a study? If not, why is it proceeding with SCADA investments prior to such a study?

RESPONSE:

a) The majority of the SCADA investment outlined in Table 4-5 is independent of the communication backhaul that will be used (i.e. Engineering, Commissioning, Field devices, etc.). The estimated cost of the communication equipment is $1,500- $4,000. Given the size of API's service territory, API anticipates that different communication solutions will be required depending on the area being considered. For this reason, API intends to perform the detailed communication study on a case-by-case basis during the Engineering effort.

2.0-VECC -16
Reference: Exhibit 2, Appendix 2A-DSP

a) API is requesting approval for only two ACM projects: (1) Echo River and (2) API Sault Facility Replacement Project. However we are unable to locate evidence supporting documentation including:

i. a detailed business plan;

ii. detailed description of the projects Sault Facility replacement project, including real-estate studies;

iii. detailed descriptions of the various components of the Echo River project including potential cost sharing with Hydro One;

iv. AACE or other forms of contractor cost estimates for either project, including contingencies for the projects' various components; and

v. project schedules and timelines.

Has this type of supporting evidence been filed and if not when does API expect to be in the position to provide greater detail on these projects?

RESPONSE:

a) Supporting documentation is referenced and/or discussed below for each of the ACM projects.

Echo River TS

Echo River TS is owned by Hydro One and supplies power to the east of Sault areas serviced by API. The proposed project is a result of API's collaborative efforts with Hydro One (and previously GLPT) to identify an optimal solution to address the identified need through the OEB-mandated Regional Planning process. API has not produced a formal business plan for this project, however the information that would typically be included in a business plan has been documented in detail in API's DSP, as required by the Chapter 5 Filing Requirements. This includes the identification of the need to provide a reasonable contingency for failure of the existing single transformer (see DSP pp. 70-71), API's efforts to coordinate planning with third parties (i.e. GLPT/Hydro One; see DSP pp. 25-26), and analysis of alternatives considered to address the contingency need (see DSP p.143 and response to 2-Staff-20). Further, a recent distribution planning study conducted by SNC-Lavalin (see DSP Appendix K) confirmed the voltage violations that result from the loss of the Echo River TS supply, and also recommend the installation of a second transformer at this location.

The scope of the Echo River TS project includes the purchase and installation of a second 230/34.5 kV power transformer, and associated modifications to buswork, switching devices, protections and other components required to permit the transformer to be placed in service within a reasonable period (24-48 hours). Cost estimates for this project are based on initial estimates from Hydro One, on the assumption that API would be required to contribute 100% of the capital costs. API anticipates that upon receiving ACM approval for the project in the current application, it would confirm with Hydro One to proceed with detailed engineering on the preferred option of installing a "hot spare" transformer. API expects that it would determine detailed cost, schedule and required contributions with Hydro One in parallel with detailed engineering. Hydro One has confirmed its commitment to a 2021 in-service date in the Regional Planning Status letter, included as Appendix E to API's DSP.

Sault Facility Replacement Project

In addition to the Strategic Facility Planning document provided as Appendix M to the DSP, a final business case was completed on August 8, 2019. This business case and supporting documentation that includes detailed descriptions containing detailed descriptions of the project, has been filed in response to 2-Staff-29(a).

Please see the responses to the following interrogatories for further detail:

- 2-Staff-29
- 2-Staff-30
- 2-SEC-20

3.0 OPERATING REVENUE (EXHIBIT 3)

3.0-VECC-17

Reference: Exhibit 3, pages 13 and 26
Load Forecast Model, Input – Adjustments and Variables Tab

a) Are the Wholesale Purchases values set out in Exhibit 3, Table 3 the same as those in Column B of the Input – Adjustments and Variables Tab of the Load Forecast Model? If not, what is the difference?

b) Do the Wholesale Purchases values for 2009-2018 in the Load Forecast Model include volumes to serve Dubreuil and its associated retail customers?

c) Do values used in both references include purchases by Algoma from embedded generation?

   i. If yes, please provide breakdown between embedded generation and purchases from the IESO.

   ii. If not, please revise the Load Forecast Model so as to include embedded generation in wholesale purchases and provide a revised version of the model.

d) The Adjustments and Variables Tab includes other adjustments (i.e., TrapRock1 and TrapRock2) to the historic whole purchases values for purposes of developing the load forecast model. Please explain the purpose of these adjustments and why they are appropriate.

RESPONSE:

a) The values are the same.

b) Yes.

c) The values do not include purchases from embedded generation. In the revised load forecast model filed with these interrogatory responses, monthly purchases from embedded generation are included in Column I of the “Input – Adjustments and Variables” Tab, and the formulas in column J have been adjusted to add these values to the unadjusted wholesale purchases.

d) Consistent with the approach in API’s previous cost of service application, the load forecast model was tested to see if the regression would improve by removing any of the larger customer loads from historical values. In the model as filed, API’s strategy was to remove any load that that was inconsistent over the period of the regression. The load related to two of API’s larger accounts was only in effect for 8 of the 10 years therefore API’s strategy was to remove this load in an effort to normalize the historical wholesale load prior to running the regression. In updating the model to include purchases for embedded generation, the regression statistics improve if the historical wholesale values are normalized to exclude the load from all six accounts listed on the “Inputs – Adjustments and Variables” Tab and the formulas in column J have been updated accordingly.

3.0-VECC-18

Reference: Exhibit 3, pages 17-18

a) Precisely what is the basis for the Employment variable (i.e., definition) used in the Load Forecast Model.

b) It is noted that the coefficient for the Employment variable is negative such that increases in the value for the variable will lead to a reduction in the predicted wholesale purchases.

  i. Based on the definition of the variable, does this result make sense intuitively?

  ii. If not, please provide an alternative Load Forecast model where Employment is not included as an explanatory variable.

c) Apart from employment, were any other variables that associated with economic activity (e.g., GDP, customer count etc.) specifically tested for inclusion in the model? If yes, what were the results?

RESPONSE:

a) The variable originates from the Stats Canada website. More specifically the CANSIM 292-0122 which is no longer available. Statca.gc.ca defines the variable used namely Employment (x 1,000) as such;

> *Number of persons who, during the reference week, worked for pay or profit, or performed unpaid family work or had a job but were not at work due to own illness or disability, personal or family responsibilities, labour dispute, vacation, or other reason. Those persons on layoff and persons without work but who had a job to start at a definite date in the future are not considered employed. Estimates in thousands, rounded to the nearest hundred.*

b) VECC is correct in that the employment factor used in the May 17, 2019 application produces counter intuitive results and should have been excluded from the calculations. The table below shows the results of the May 17, 2019 regression without the effects of the Employment variable.

Equation Parameters	
R Squared	0.9167
Adjusted R Squared	0.9146
Standard Error	959414.5625
F - Statistic	425.6013

91.46% of the change in WS can be explained by the change in the 3 independent variables to +/- on result of Regression Equation

Multiple Regression Equation	Coefficients	Standard Error	t Stat	p Value
Intercept	12,903,662.559	284,386.402	45.374	0.00%
HDD	11,397.646	398.097	28.630	0.00%
CDD	34,424.284	7,546.963	4.561	0.00%
Spring/Fall	-496,161.017	200,424.404	-2.476	1.47%

95% Confidence/Autocorrelation	
0.887	Durbin-Watson Statistic
1.67 - 1.74	Positive autocorrelation detected
2.681	Critical F-Statistic - 95% Confidence
80.13%	Confidence to which analysis holds

Independent Analysis			Auto Correlation	Multicoll
R Squared	Coefficient	Intercept	Dl=1.69 Du=1.72 DW-Stat	Adjusted R-Squared against other Indep
88.13%	10272.24	13412634.00	0.33	44.83%
18.84%	-84759.30	18331426.00	0.98	51.10%
4.11%	-1324554.25	18258134.00	1.34	22.31%

In updating the LF to include adjustments for Customers #1 to #6 as well as the embedded generation, the results for the Employment variable are no longer counter intuitive. The use of the Employment variable improves the Adjusted R-Squared by 4% therefore API is opting to keep the variable as part of the equation. The revised model supporting the results shown in the table below is being filed along with these responses.

Equation Parameters	
R Squared	0.9535
Adjusted R Squared	0.9519
Standard Error	609528.7500
F - Statistic	589.6832

95.19% of the change in WS can be explained by the change in the 4 independent variables to +/- on result of Regression Equation

Multiple Regression Equation

	Coefficients	Standard Error	t Stat	p Value
Intercept	-4,120,458.956	2,113,289.953	-1.950	5.36%
HDD	10,285.733	274.946	37.410	0.00%
CDD	27,113.474	4,795.106	5.654	0.00%
Spring/Fall	-403,605.728	130,116.791	-3.102	0.24%
Employment	48,004.527	8,067.204	5.951	0.00%

c) The other variables tested are shown in the tab entitled "Input-Adjustments and Variables" and were the "Ontario Cost of Electricity" "Customer Number" and "Days per month". The table below shows the regression results using the adjusted wholesale as presented in the May 17, 2019 application.

Equation Parameters	
R Squared	0.9743
Adjusted R Squared	0.9727
Standard Error	459015.6250
F - Statistic	607.1437

97.27% of the change in WS can be explained by the change in the 7 independent variables to +/- on result of Regression Equation

95% Confidence/Autocorrelation	
0.822	Durbin-Watson Statistic
1.60 - 1.81	Positive autocorrelation detected
2.087	Critical F-Statistic - 95% Confidence
93.41%	Confidence to which analysis holds

	Multiple Regression Equation				Independent Analysis			Auto Correlation	Multicollinearity	
	Coefficients	Standard Error	t Stat	p Value	R Squared	Coefficient	Intercept	Dl=1.69 Du=1.72 DW-Stat	Adjusted R-Squared against other Indep	Variables With RSQ at > 90%
Intercept	34,684,168.451	17,846,208.300	1.944	5.45%						
HDD	9,756.931	219.954	44.359	0.00%	90.00%	8788.93	8707579.00	0.33	57.17%	
CDD	21,527.242	3,745.941	5.747	0.00%	19.30%	-72646.62	12917198.00	0.98	52.96%	
Ontario cost of electricity	-14,110.918	2,159.554	-6.534	0.00%	3.92%	-23150.20	15625101.00	0.11	29.25%	
Customer #	-3,311.469	1,475.904	-2.244	2.68%	0.31%	-4933.61	69887520.00	0.42	13.61%	
Days in month	377,631.346	54,656.191	6.909	0.00%	0.58%	-261906.47	20259616.00	2.98	4.27%	
Spring/Fall	-631,138.267	101,112.530	-6.242	0.00%	4.99%	-1236434.30	12904963.00	1.34	27.66%	
Employment	11,657.547	7,611.053	1.532	12.84%	9.93%	-108478.11	39821744.00	0.24	50.63%	

3.0-VECC-19

Reference: Exhibit 3, pages 24-26
Load Forecast Model, Input Customer Data Tab

a) Are the historical customer counts set out in Table 10 based on the customers served directly by Algoma over the period (with Dubreuil treated as an embedded distributor)? If not please, provide these values for each customer class.

b) Please provide the 2018 year-end and the June 2019 customer count for each customer class for Algoma (with Dubreuil treated as an embedded distributor customer).

c) Is Dubreuil Lumber itself still a customer of Algoma? If yes, why is the R2 customer count reduced by one?

d) Please provide the 2018 year-end and the June 2019 customer count for each customer class served by Dubreuil as an embedded distributor. (Note: If Dubreuil Lumber is now a retail customer of Algoma, please include it in the "count" and indicate which customer class it is in).

e) Please provide the average annual customer count for each of the years 2009-2018 for each of the customer classes served by Dubreuil as an embedded distributor. (Note: Please indicate those years where Dubreuil Lumber was itself an end-user of electricity and include it in the "counts").

f) It is noted that, for 2020, the Street Lights customer count is based on increasing the 2018 value by 50. Please explain the basis for using this approach for the 2020 forecast as opposed adding 50 to a 2020 forecast for Algoma (excluding Dubreuil) based on the historic geomean (as was done for the other customer classes).

RESPONSE:

a) Yes.

b) The customer counts are provided in the table below. Dubreuil Lumber is included as a single R2 customer, and individual retail accounts in Dubreuilville are excluded.

Rate Class	2018 Year-End	June 2019 Month-End
R1(i)	7662	7693
R1(ii)	961	961
R2	39	39
Seasonal	3061	3024
Street Lights	1075	1075

c) The historical R2 account associated with Dubreuil Lumber is only being used for the purpose of billing costs and revenues to the deferral account until the end of 2019. The service to the lumber mill that is downstream of the bulk 44 kV meter has been disconnected and Dubreuil Lumber would be required to meter this service as a new account if it ever chooses to reconnect.

d) The customer counts are provided in the table below. As confirmed in part c) above, Dubreuil Lumber's historical R2 account will no longer be active. Dubreuil Lumber does have a number of small commercial accounts in the town of Dubreuilville, which have been billed as individual retail accounts since 2017, and are therefore included in both the 2018 and 2019 totals below.

Rate Class	2018 Year-End	June 2019 Month-End
Residential	311	311
Commercial	46	47

e) API does not have the data required to respond to this request. API is only able to provide averages for the 2017 to 2019 period, noting that it started gathering this data in May of 2017.

Rate Class	2017 (May-Dec)	2018	2019 (Jan-Jun)
Residential	311	310	312
Commercial	43	45	47

f) Based on the June 2019 counts provided in part b) above, API agrees that the approach contemplated in the question has merit, and has revised the load forecast model accordingly.

3.0-VECC-20

Reference: Exhibit 3, page 22 (Table 8)
Load Forecast Excel Model, Forecast Tab (Columns D, E and G)

a) It is noted that, in the Load Forecast Model, the HDD and CDD monthly values used for the 2019 and 2020 forecasts are different. Why is this when the forecast is based on 10 years of historical data?

b) It is noted that the 10 year average of the monthly values for HDD and CDD set out in Table 8 do not match the HDD and CDD monthly values used in the Excel Model to forecast wholesale purchases for either 2019 or 2020. Please explain.

c) What is the basis for the 2019 and 2020 forecast values for Employment as used in the Load Forecast Model?

d) What are the "predicted" wholesale purchases for 2017 and 2018 based on the 10 year average of the monthly values for HDD and CDD used for 2020?

RESPONSE:

a) The formulas for 2020 inadvertently referred to 2010 to 2019 values instead of 2009 to 2018 values. The formulas have been corrected accordingly in the revised load forecast model.

b) The formulas in the excel model inadvertently averaged only 9 of the 10 years. The formulas have been corrected accordingly in the revised load forecast model.

c) The employment variable (CANSIM 282-0122) indicates the number of persons in the labour force in that region. In regression with multiple independent variables, the coefficient indicates how much the dependent variable is expected to increase (kWh) when that independent variable increases by one, holding all the other independent variables constant. For details on API's intention in using the variable in question, please see responses to 3.0 VECC-17. The Employment Stats was the only variable that used a forecast methodology different than the Average. To forecast the "Employment Stat", API used the Linear Trending instead. To forecast a linear trend line for the Employment Stat, API used a Microsoft Excel LINEST function to calculate the statistics for a straight line and return an array describing that line. API then multiplies the "period count" by the "Slope" and then adds it to the "Intercept".

d) Please see table below. API notes that actual HDD and CDD for 2017-2018 are available therefore API is not proposing to use calculated values in its forecast.

	Actual	Predicted	HDD 2009-2016 avg	CDD 2009-2016 avg
Jan-17	14217028.00	16584670.26	895.23	0.00
Feb-17	12901952.00	15437202.05	793.00	0.00
Mar-17	13971201.00	13976530.46	682.76	0.00
Apr-17	10498810.00	11800630.59	458.55	0.03
May-17	9942487.00	9874363.00	236.09	4.87
Jun-17	8794731.00	9384223.62	105.80	10.54
Jul-17	9593147.00	9815521.34	42.12	40.86
Aug-17	9465230.00	9725703.85	42.08	38.10
Sep-17	8870447.00	9235136.87	129.70	9.09
Oct-17	9772971.00	10849104.16	322.68	0.19
Nov-17	12203098.00	12244627.49	469.11	0.00
Dec-17	16061539.00	14982266.17	710.50	0.00
Jan-18	16624671.00	16531220.27	885.83	0.00
Feb-18	14549432.00	15447311.92	798.65	0.00
Mar-18	13969451.00	13777562.63	683.02	0.00
Apr-18	12598153.00	11559981.10	462.68	0.03
May-18	9786784.00	9488495.29	228.24	5.48
Jun-18	9032830.00	9093542.88	103.26	9.45
Jul-18	10160881.00	9633079.26	36.43	44.97
Aug-18	10093070.00	9571205.59	38.67	39.71
Sep-18	9599775.00	9233641.36	134.27	9.60
Oct-18	11735841.00	10779422.38	315.37	0.21
Nov-18	13348024.00	12412824.16	475.66	0.00
Dec-18	14932444.00	14981413.46	705.75	0.00

- API used an 8-year avg as 2007-2009 are not readily available

3.0-VECC-21

Reference: Exhibit 3, pages 27-31
Load Forecast Excel Model, Bridge and Test Year Class Forecast Tab

a) Please confirm that the additional 2020 Street Lights load associated with the inclusion of Dubreuil's Street Lights is 26,650 kWh (i.e. 533 x 50) which would account for 0.32% of the DLI 44 kV supply (26,650/8,373,019). If not, what is the additional kWh that were added?

b) It is noted that the Residential and GS<50 customers are attributed 52.48% and 36.30% of the DLI 44 kV supply (per Tables 11 and 12). What accounts for the remaining 11% of the DLI 44 kV supply?

RESPONSE:

a) Confirmed. Without rounding, the result is 26,651 kWh, or 0.36% of the 44 kV supply.

b) The remaining 11%, or 912,998 kWh is attributed to losses. This includes both losses on API's system (since the 8,373,019 starting value for 44 kV supply is loss-adjusted), and losses on DLI's distribution system beyond the historical 44 kV supply point.

3.0-VECC-22

Reference: Exhibit 3, pages 34-39
Load Forecast Excel Model, CDM Adjustment & CDM Allocation Tabs

a) With respect to page 34, please provide a copy of Algoma's most recently approved CDM plan.

b) With respect to Table 18, which years' CDM results are based on actuals and which are based on Algoma's CDM Plan?

c) With respect to Table 18, why is there no loss of persistence in savings attributed to 2018 CDM programs for the years after 2018?

d) With respect to page 36, please explain the basis for the weightings used for the manual load forecast adjustment (i.e., 2018- 1.0; 2019 – 0.5 and 2020 – 1.0).

e) Please explain why the total saving attributable to 2018-2020 programs in Table 19 (8,289,615 kWh) does not equal the total in Table 18 for the impact in 2020 of 2018-2020 programs (8,295,615 kWh).

f) With respect to the CDM Allocation Tab, please explain why savings from 2017 programs are included in the determination of the class shares when the results being allocated are attributable to 2018-2020 programs.

RESPONSE:

a) Please see Excel file "API_IRR_CDM Plan Submission_20180116.xlsx."

b) 2015-2017 values in rows "2015 CDM Programs" through "2017 CDM Programs" were based on IESO 2017 verified results from the verified results spreadsheet filed with the application. 2018-2020 values in these same rows reflect the IESO's estimated persistence of 2015-2017 savings, from this same data source.

   All values in rows "2018 CDM Programs" through "2020 CDM Programs" were based on API's most recently approved CDM plan.

c) In reviewing the 2015-2017 savings and persistence from the IESO final verified results, API determined that there was little to no loss of persistence in the first few years for most programs. Only the 2017 Save On Energy Coupon and Instant Discount programs had a material change between first year savings and persistence estimates (2015 and 2016 did not have material changes for these same programs. Since approximately 2% of API's 2018-2020 planned savings were related to these programs (which had little to no persistence changes for 2 of 3 recent years) and the remaining 98% of planned savings were related to programs with little to no change persistence changes for 2015-2017, API did not make any adjustments to persisting savings from 2018-2020 programs. API notes that on July 15, 2019, the OEB updated the Filing Requirements to direct distributors to use the IESO's monthly Participation and Cost reports for 2018 CDM savings. Please see response to 3-Staff-40(f), where persistence effects for 2018 projects have been factored into 2020 savings based on the most recent IESO report.

d) The values in the May 17, 2019 model were populated in the load forecast model template based on 2019 test year filings. In finalizing the model to reflect API's 2020 test year, the step of updating the weighting factors was inadvertently overlooked. The 2018, 2019, and 2020 weighting factors should have been set to 0.5, 1 and 0.5 respectively. The weighting factors have been updated accordingly in the revised load forecast model filed with these interrogatory responses.

e) API notes that the CDM plan included placeholder values of 1 MWh for two programs (Industrial Accelerator Program and Energy Performance Program) for each year 2018-2020, for a total of 6 MWH. While no specific projects were planned at the time of the CDM plan submission, including the placeholder values would allow API to capture savings from these programs if the event that any projects materialized. The allocation of 2018-2020 CDM plan savings to rate classes for adjustments to the 2020 load forecast did not include these programs since no actual projects are expected. A revised Appendix 2-I has been filed in response to 3-Staff-40(g) to incorporate adjustments required as a result of the revocation of the 2015-2020 Conservation First Framework and related updates to the OEB's filing requirements.

f) The load forecast model allows for the persistence of a prior year's results by class to allocate the future year target between rate classes (i.e. zeroing out columns I and J would have led to the 2018-2020 target value in cell N32 being allocated based on 2017 actual results. API determined that the makeup of its 2018-2020 target was sufficiently different than 2017 results to warrant direct input of target kWh/kW by rate class in columns I and J. The 2017 results should have been zeroed out to avoid skewing the 2018-2020 allocations. API has made this correction in the revised load forecast model filed with these interrogatory responses.

3.0-VECC-23

Reference: Exhibit 3, page 57

a) In 2019 were all of the retail customers of Dubreuil billed based on Algoma's approved 2019 rates?

b) If not, please provide two tables for revenues at current rates: one based on the customers served by Algoma in 2019 at Algoma's approved rates (Note: For this table please exclude any customers who were served by Dubreuil in its role as a "distributor") and a second setting out the customers Dubreuil served based on their 2020 forecast loads and the 2019 rates that they paid.

RESPONSE:

a) Yes, as of August 7, 2019.

b) Not applicable, based on the response to part a). The 2020 forecasted loads in Table 32 at the above reference includes the 2020 forecasted loads for all of the former retail customers of Dubreuil Lumber Inc., which are now customers of Algoma Power Inc.

3.0-VECC-24

Reference: Exhibit 3, pages 59 and 66-67

a) Based on the variance analysis of the 2020 vs 2019 forecasts (page 66), no adjustment appears to have been made to Other Operating Revenues to account for the fact Dubreuil's former customers will be customers of Algoma in 2020. What USOA accounts will be impacted by this change (e.g., SSS Admin) and what is the expected impact for 2020 for each of these accounts?

b) It is noted that both Table 33 and Appendix 2-H include Expenses for Non-Utility Operations (USOA 4380).

i. Please confirm that these expenses are Algoma's allocation of CNPI-Distribution's shared IT costs (per page 67).

ii. Please explain why these expenses are included as an offset against Other Operating Revenue whereas other shared costs allocated from CNPI-Distribution are not.

c) Please provide the Other Revenue Offsets for the first six months of both 2018 and 2019 broken down per Table 33.

d) Does Algoma have any microFIT customers and, if so, where are the revenues from the monthly service charges included in Table 33?

RESPONSE:

a) Based on a net increase of 356 customers (311 R1(i) + 46 R1(ii) – 1 R2), SSS admin revenue would increase by an immaterial amount of approximately $1068. Late payment charges may also be affected; however, API expects that the impact would be immaterial and is unable to quantify the amount since API does not have any historical late payment charge data for these customers. API does not expect an impact to the remaining Other Revenue accounts.

b)

i. Confirmed.

ii. API has allocated the shared costs with an intent to be consistent with how CNPI-Distribution has classified the revenues for the same shared costs. For the shared IT costs, the revenue has been recorded in CNPI-Distribution OEB 4375, while the cost has been recorded in OEB 4380 for API. Both of these USoA accounts map back to Other Revenue within the Revenue Requirement model.

c) See table below.

	Reporting Basis	**MIFRS**	**MIFRS**
		2018 JUN YTD	**2019 JUN YTD**
	USoA Description		
4235	**4235-Miscellaneous Service Revenues**	-$26,053	-$28,891
4225	**4225-Late Payment Charges**	-$23,685	-$29,986
4082	4082-Retail Services Revenues	-$2,300	-$2,279
4084	4084-Service Transaction Requests (STR) Revenues	-$14	-$6
4086	4086-SSS Administration Revenue	-$17,509	-$17,508
4210	4210-Rent from Electric Property	-$119,874	-$119,515
4215	4215-Other Utility Operating Income	$0	$0
4220	4220-Other Electric Revenues	-$946	-$210
4305	4305-Regulatory Debits	$46,489	$46,489
4325	4325-Revenues from Merchandise Jobbing, Etc.	-$33,633	-$29,542
4330	4330-Costs and Expenses of Merchandising Jobbing, Etc.	$32,536	$27,303
4355	4355-Gain on Disposition of Utility and Other Property	-$3,283	-$32,001
4360	4360-Loss on Disposition of Utility and Other Property	$0	$0
4380	4380-Expenses of Non-Utility Operations	$286,141	$273,265
4390	4390-Miscellaneous Non-Operating Income	$0	$0
4398	4398-Foreign Exchange Gains and Losses, Including Amortization	-$236	$224
4405	4405-Interest and Dividend Income	-$21,045	-$29,026
	Total	$116,590	$58,317

	Specific Service Charges	-$26,053	-$28,891
	Late Payment Charges	-$23,685	-$29,986
	Other Distribution/Operating Revenues	-$140,642	-$139,518
	Other Income or Deductions	$306,970	$256,712
	Total	$116,590	$58,317

d) Yes, API has microFIT customers. The monthly service charge revenue is recorded in OEB 4235.

4.0 OPERATING COSTS (EXHIBIT 4)

4.0 -VECC-25
Reference: Exhibit 1, page 26/ Exhibit 4, pg. 34

a) Please explain how the bad debt costs were estimated for 2019 and 2020.

RESPONSE:

a) Based on the timing of the 2019 and 2020 budget process, as described in response to 1-SEC-3, API only had actuals up to 2017 at the time of determining its 2019 and 2020 budgets. 2015 and 2016 actuals of $62-64k were reasonably close to prior year budgets of $71k. While 2017 actuals were lower than this amount, there was some uncertainty as to what impacts the winter disconnection moratorium and more recent changes to OEB customer service rules would have on API's bad debt costs over the longer term and API therefore did not adjust its budget from prior years.

API notes that the response to 4-SEC-26 shows a credit balance in bad debt expense for 2019 YTD. This is due to the fact that API has not yet run a write-off simulation in 2019, so this balance should not be viewed as indicative of 2019 bad debt expense.

4.0 -VECC-26
Reference: Exhibit 4, Section 4.6.1, page 64-

a) Is API a member of the Electricity Distributors Association? If yes, please provide the annual fees paid to the EDA in the years 2015 through 2020 forecast (or the allocated share of fees if paid by an API affiliate).

RESPONSE:

a) Yes, API is a member of the EDA. The allocated share of annual fees were as follows:

Year	$ Amount
2015	15,972
2016	16,106
2017	14,137
2018	14,359
2019	14,644
2020	14,923

4.0 -VECC-27
Reference: Exhibit 4, page 41

a) Has API signed a new lease for the Sault Ste. Marie facilities? If yes, please provide the terms of the lease. If not, please provide the expected date for finalization of negotiations.
b) In the interim is API on a month-to-month rent agreement for the current site? If yes, please provide the monthly rental amount.
c) What are the terms of vacating the property under the current lease?

RESPONSE:

a) API has not signed a new lease. API is currently in discussion with Hydro One regarding a sublease consistent with the terms of the head lease. Hydro One is currently negotiating a short term lease (head lease) with Brookfield. All parties are targeting a new short term lease to be finalized before the expiry of the current lease.

b) No. The current lease is valid until December 30 , 2019.

c) Early Termination notice must be served 18 months prior to the termination.
Surrender of the premise - at the expiry of the Term or other sooner termination, to quit the Premises and surrender the Premises in good order and condition as required under the provisions of Section 10.11 (Maintenance and Repairs), subject only to the provisions of Section 10.14 (Replacement of Damaged Building), and all the right, title and interest therein of the Subtenant ceases and vests in the Sublandlord. Except to the extent expressly agreed by the Sublandlord in writing, no trade fixtures, furniture or equipment shall be removed by the Subtenant from the Premises either during or at the expiration or sooner termination of the Term except that (a) the Subtenant, if not in default hereunder, may at the end of the Term remove its trade fixtures, furniture and equipment; and (b) the Subtenant shall at the end of the Term remove such of its trade fixtures, furniture and equipment as the Sub landlord shall require to be removed. The Subtenant shall, in the case of every removal either during or at the end of the Term, make good any damage caused to the Premises and the Buildings by the installation and removal.

4.0 -VECC-28
Reference: Exhibit 4, pg. 49, Table 8 – Appendix 2-K

a) Please amend Table 8 (Appendix 2-K) to show the total amount of compensation capitalized and expensed in each year.
b) Please provide a list of positons operating out of an API location in 2015, currently and expected to be working in the API service territory at year-end 2019.

RESPONSE:

a) See response provided in 4-SEC-29.

b) See table below. Please note that the corporate positions identified in the table reflect the number of staff that work on corporate functions, and are based out of the API location. In preparing the number of FTE as well as salaries, wages and benefits in Appendix 2-K, similar to other corporate administration staff, only an allocated portion of this staff member would be included in the values reported.

API POSITION	2015	2019
Regional Manager	1	1
Administrative Assistant	1	-
Admin/HR Assistant	-	1
Manager Forestry	1	-
Vegetation Management Coordinator	1	1
Forestry Technician	1	1
Forestry Supervisor	1	1
Group Leader Forestry	1	1
Utility Arborist Designate	3	3
Utility Arborist	2	3
Utility Arborist Apprentice	1	-
Supervisor Distribution Engineering	1	1
Distribution Engineer	1	1
Distribution Technician	2	2
Lands Technician	1	1
Records Technician	1	1
Admin Support	0.5	-
Supervisor Technical Services	1	1
Electrical Trade Technician	2	2
Customer Service Rep (Field)	2	1
Supervisor Customer Service	1	1
Customer Service Agent	-	5
Customer Service Rep	2	-
Billing Clerk	1	-
Admin Support	0.5	-
Superintendent Fleet, Facilities & Materials	1	1
Operations Technician	1	1
Tool Repair Person	1	-
Stores Clerk	1	-
Equipment Mechanic Group Leader	1	-
Equipment Mechanic	-	1
Utilityperson/Storekeeper	-	2
Supervisor Line Services	1	1
Group Leader Lines	3	3
Line Trade Technicians	14	14
Distribution Specialist	1	1
Admin Assistant	1	-
Operations/HS&E Administrator	-	1
Technical Services/Work Methods Specialist	-	-
Corporate:		
Asset Analyst	1	1
Systems Administrator	1	1
HS&E Advisor	1	-
HR Coordinatior	1	-
Temp/Seasonal (Approx. 9 mths each year)		
Customer Service	1	-
Labourer	2	3
Contract Monitor	2	2
TOTAL	**63**	**60**

4.0 -VECC-29
Reference: Exhibit 4, pg. 59-

a) Please explain why the shared IT services of $525,645 in 2015 were not anticipated in the Board approved amounts for shared services.

RESPONSE:

a) Shared IT assets were anticipated in 2015 Board approved amounts. Please refer to section titled 'Allocation of Shared Assets' on the page preceding the page referenced for this question. To add further clarity, the $525,645 referenced in this question is the shared IT assets from CNPI Distribution allocated to API. In 2015 Board Approved, API's portion of the IT shared assets were added to API's calculation of rate base which in turn resulted in revenue requirement. See pages 10-11 of Exhibit 2 for further discussion on shared IT assets. In accordance with Board staff's preference as outlined in its submission dated October 17, 2014 within EB-2014-0055, instead of including a portion of the shared assets in rate base for amounts presented in this Application for 2015 Actual to 2020 Test Year, API has included a shared IT charge within OEB 4380. These amounts have been reported in Table 12 referenced in this IR.

4.0 –VECC-30
Reference: Exhibit 4- pages 60-

a) Please explain why shared service and corporate cost allocations have exceeded the pace of inflation when comparing 2015 actual costs to 2020 forecast costs (~16% increase over the period).

b) What "building" is API paying building rent for?

RESPONSE:

a) The material increase over the period related to an increase in administrative services allocated to API from CNPI Distribution. API has highlighted shared services from CNPI Distribution as a cost driver in Table 5 of Exhibit 4. There were several factors outlined on page 30 of Exhibit 4, outside the pace of inflation that drove the change in dollars allocated.

b) This is the building located at 1130 Bertie Street in Fort Erie, where the majority of the shared service staff are based.

4.0 –VECC-31

Reference: Exhibit 4, pages 70-71 Appendix 2-M (Table 15)

a) Please provide the actual one-time application related costs incurred to-date in the following categories (as per Table 14):

- Legal costs
- External Consultant costs
- Internal staff costs
- Intervenor costs

b) What portion of the one-time regulatory costs are included in the presentation of OM&A costs as shown in Appendix 2-JA for 2018, 2019 and 2020?

RESPONSE:

a) Application related costs incurred to date are as follows:

Cost Category	Total Costs Incurred to June 30, 2019
Legal	$12,816
External Consultants (Incl Customer Engagement)	$99,844
Internal Staff*	$0
Intervenor	$0
Total	**$112,660**

*API internal labour costs have not been charged to one-time application related costs.

b) Only the amortized portion of the one-time costs are included in the presentation of OM&A costs in Appendix 2-JA. $44,629 is included for 2015-2019, corresponding to 2015 approval of $225,000 in one-time cost to be amortized over 5 years. $181,004 is included in the 2020 forecast, based on the following one-time costs to be amortized over the 2020-2024 period:

Cost Category	Total One-Time Costs	Amount Included in 2020
Application Related Costs	$353,500	$70,700
DLI Transaction and Integration Costs	$551,520	$110,304
Total One-Time Costs	**$905,020**	**$181,004**

4.0 –VECC-32
Reference: Exhibit 4, page 84

a) Please show the actual income and capital taxes paid by API in each year 2015 through 2018.

RESPONSE:

a) See table below.

	2015	2016	2017	2018
Federal Income Tax Paid	$ 238,950	$ 176,908	$ 200,770	$ 240,537
Provincial Income Tax Paid	$ 179,217	$ 135,087	$ 153,924	$ 184,412
Total Income Tax Paid	**$ 418,167**	**$ 311,995**	**$ 354,694**	**$ 424,949**

**Capital tax rate was 0% throughout the period requested, therefore $nil capital taxes were paid.*

4.0 –VECC-33
Reference: Exhibit 4, pages 90-93
EB-2014-0055, Exhibit 3, Tab 2, Schedule 1, pages 3-4

a) Please provide a copy of Appendix 4G in excel format.

b) Please confirm that the LRAM threshold value of 750,000 kWh reflects the impact of 2014 and 2015 programs on the 2015 load forecast used in EB-2014-0055.

c) Please explain why the current LRAM claim includes CDM savings in 2015-2017 from programs implemented in 2011-2014 when the threshold established in EB-2014-0055 was based on savings from 2014 and 2015 programs.

d) Please provide a revised LRAMVA Work Form that excludes savings from CDM programs implemented in 2011-2014.

RESPONSE:

a) The requested spreadsheet was filed on May 17, 2019 as "API_2020 CoS_2017 Verified Annual LDC CDM Program Results Report_20190517.xlsx"

b) Confirmed.

c) API has removed the savings resulting from 2011-2013 programs since these savings were embedded in the 2015 OEB-approved load forecast. See response to 4-Staff-59(b). Savings from 2014 programs are included since these were not embedded in the 2015 load forecast. The LRAM threshold from EB-2014-0055 is included in the LRAMVA model so that forecasted savings based on this threshold act as an offset to actual savings based on IESO verified results.

d) Based on the response to part c) above, API has filed a revised LRAMVA model that excludes savings from 2011-<u>2013</u> programs.

5.0 COST OF CAPITAL AND RATE OF RETURN (EXHIBIT 5)

5.0-VECC-34
Reference: Exhibit 5, page 6-

a) Please explain what efforts were made to determine the relative cost of the promissory note negotiated with API's affiliate and short to mid-term debt otherwise available in the market?

b) Given the description of the $12.75 million promissory note with the parent company as "*to support its capital program spending requirements until the balance is sufficient to replace it with the issuance of third party long-term debt*" why would it not be more appropriate that this debt attract the Board's short term interest rate?

RESPONSE:

a) See response to b.

b) As of December 31, 2018 the affiliated debt outstanding was $12.75 million. This amount has grown from approximately $1 million in the 2015 test year and is forecast to grow to $32 million in 2024. The 2018 affiliated debt represents approximately 11% of rate base, which is materially more than the OEB's deemed short-term debt of 4% of rate base. Given the forecast term (i.e. 10 plus years) and the size of the debt, classifying as short term would not be appropriate. Also, as stated in Exhibit 5, the requirement for this funding is to support the long-term capital program, which will be replaced with 3rd party, long-term debt in the future.

The alternative to obtaining 3rd party long-term debt is not, as the question implies, treating it as short-term debt, but rather maintaining long-term debt with the affiliate which, as a matter of Board policy, will attract the Board's long-term deemed debt rate. This treatment of the affiliated debt is consistent the Report of the Board on Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, and with past practices including API's affiliated company (i.e. Canadian Niagara Power Inc.).

Notwithstanding API's position described above, short-term and long-term debt rates are applied on the basis of deemed as opposed to actual capital structure. Treating the affiliated debt as short-term debt would leave the 30-year note at 5.118% as the only long-term debt. The end result would be an increase to API's weighted average cost of debt from 4.81% (as presented in the application) to 4.96%.

7.0 COST ALLOCATION (EXHIBIT 7)

7.0 – VECC –35
Reference: Exhibit 7, page 5

a) Please provide a schedule that sets the actual derivation of the values in Table 2 starting from the 2015 OEB-approved revenue requirements for each class.

RESPONSE:

a) The following Schedule (Schedule VECC-35) reproduces the portion of API's 2019 IRM application (*with updates noted in italics)* in which API's 2019 class-specific revenue requirements were determined, on the basis of applying revenue-to-cost ratio adjustment and price-cap adjustment factors to API's 2015 approved revenue requirements for each class.

SCHEDULE VECC-35

2019 Rate Design

In API's 2015 cost of service proceeding, EB-2014-0055, the Board approved the following revenue to cost ratios and allocation of class revenues as the basis of the electricity distribution rates effective January 1, 2015.

Table 3

EB-2014-0055 Target Revenue to Cost Ratios						
	Allocation of Revenue Requirement Including Net Income	Misc. Revenue	Allocation of Distribution Revenue Requirement Including Net Income	Distribution Revenue at Status Quo Equivalent Rates	Target Revenue to Cost Ratio	Adjusted Distribution Revenue to Achieve Target Revenue to Cost Ratios
Residential - R1	15,134,936	292,845	14,842,091	16,601,471	110.63%	16,451,085
Residential - R2	3,731,937	75,827	3,656,111	4,093,854	110.74%	4,056,974
Seasonal	3,719,751	79,308	3,640,443	1,965,214	60.00%	2,152,542
Street Lighting	696,314	18,778	677,536	155,642	25.04%	155,579
	23,282,938	466,758	22,816,181	22,816,181		22,816,181

Further, the Board directed API to increase the revenue to cost ratios of the Seasonal and Street Lighting customer classes as defined in the table below.

Table 4

Future Revenue to Cost Ratio Design Criteria - EB-2014-0055					
	2015	2016	2017	2018	2019
Residential - R1	110.63%	Beneficary			
Residential - R2	110.74%	Beneficary			
Seasonal	60.00%	66.00%	72.00%	78.00%	85.00%
Street Lighting	25.04%	10% Total Bill Impact			

The revenue to cost ratio for the Seasonal class is set to increase in increments each year while the Street Lighting class will increase annually by a measure limited by the total bill impact for that class. Annual incremental increases will cease once the class has reached the lower threshold of the Board's policy guideline.

The following two tables show the Board accepted rate design for the electricity distribution rates effective January 1, 2015.

Table 5

Accepted Residential R1 & R2 2015 Electricity Distribution Rates and RRRP Funding - EB-2014-0055

2015 Distribution Base Rate Determinations											
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8496	105,791,701		13.6%	86.4%	22.02	0.1343	2,245,034	14,206,051	16,451,085
Residential - R2	kW	50		198,901	12.0%	88.0%	812.05	17.9473	487,230	3,569,744	4,056,974
									2,732,264	**17,775,795**	**20,508,059**
The Accepted 2015 Application of Rate Indexing Methodology											
Delivery Charges Indexed by Simple Average of Other LDC Increases in Current Year											
Simple Average Increase in Delivery Charge for 2015 using the 2014 Board Approved RRRP Adjustment Factor											**0.79%**
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8496	105,791,701		40.7%	59.3%	23.34	0.0328	2,379,862	3,465,392	5,845,254
Residential - R2	kW	50		198,901	36.8%	63.2%	600.83	3.1131	360,498	619,199	979,696
Transformer Ownership Allowance - Allocated to the Residential - R2 class										74,096	74,096
The Rural and Remote Rate Protection Amount Required for 2015 (EB-2014-0055)											$13,757,205

Table 6

Accepted Seasonal and Street Lighting Distribution Rates - EB-2014-0055

2015 Distribution Base Rate Determination											
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Seasonal	kWh	3138	7,731,414		47.5%	52.5%	27.15	0.1462	1,022,458	1,130,085	2,152,542
Street Lighting	kWh	1018	804,705		8.6%	91.4%	1.10	0.1767	13,380	142,199	155,579
									1,035,837	**1,272,284**	**2,308,121**

The first step in the Annual Price Cap Index Adjustment and 2019 Rate Design is to adjust the revenue to cost ratios of the classes to comply with the direction of the Board in the matter of EB-2014-0055. The 2019 approved fixed and variable rates for the Street Lighting class were increased (while maintaining the historical fixed/variable split) to the point of achieving a total bill impact of approximately 10%. Once these rates were determined, the resulting 2019 Street Light Class Revenue was calculated using the proposed 2019 rates and the approved billing determinants from the 2015 Test Year. The 2019 revenue requirement was then converted to a 2015 equivalent revenue requirement (using the price cap adjustment factors for 2016-2019), in order to re-balance the class revenue allocations in accordance with the EB-2014-0055

Settlement Agreement. The details of these adjustments can be found in the "2019 SL Adj for 10% Impact" tab of the API Rate Model.

Table 7 shows the re-allocated 2015 Test Year class revenues required to achieve a revenue to cost ratio of 85% for the Seasonal customer class as stipulated in Table 4 and the adjustment to the Street Lighting as described above.

Table 7

2019 Proposed Revenue to Cost Ratios - EB-2018-0017
Applied to 2015 Approved Revenue Requirement

	Allocation of 2015 Revenue Requirement Including Net Income	2015 Misc. Revenue	Allocation of 2015 Distribution Revenue Requirement Including Net Income	2015 Distribution Revenue at Status Quo Equivalent Rates	Target Revenue to Cost Ratio	Adjusted Distribution Revenue to Achieve Target Revenue to Cost Ratios
Residential - R1	15,134,936	292,845	14,842,091	16,601,471	105.07%	15,608,707
Residential - R2	3,731,937	75,827	3,656,111	4,093,854	105.06%	3,844,955
Seasonal	3,719,751	79,308	3,640,443	1,965,214	85.00%	3,082,480
Street Lighting	696,314	18,778	677,536	155,642	42.91%	280,038
	23,282,938	466,758	22,816,181	22,816,181		22,816,181

Table 8 shows the determination of the equivalent electricity distribution rates for the re-allocated class revenue shares provided in Table 7. The overall revenue and fixed/variable splits are the same as that accepted in EB-2014-0055. Equivalent electricity distribution rates are those rates required to recover the full revenue requirement in the absence of RRRP funding.

Table 8

Equivalent Distribution Rates Required to Recover the Proposed 2015 Base Revenue Requirement at the Proposed 2019 Revenue to Cost Ratios
Excluding Transformer Ownership Allowance

2019 Proposed Equivalent Electricity Distribution Rates

Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues			
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue	Reconciliation
Residential - R1	kWh	8496	105,791,701		13.6%	86.4%	20.89	0.1274	2,130,077	13,478,631	15,608,707	-
Residential - R2	kW	50		198,901	12.0%	88.0%	769.61	17.0094	461,767	3,383,188	3,844,955	-
Seasonal	kWh	3138	7,731,414		47.5%	52.5%	38.88	0.2093	1,464,178	1,618,302	3,082,480	-
Street Lighting	kWh	1018	804,705		8.6%	91.4%	1.97	0.3181	24,083	255,955	280,038	-
									4,080,105	**18,736,075**	**22,816,181**	**-**

Tables 9a, 9b, and 9c show the final price cap adjustment factors for 2016, 2017 and 2018 electricity distribution rates, while Table 9d shows the placeholder price cap adjustment factors for 2019 rates being used by API in this Application. API acknowledges that the Board is expected to determine values for the 2019 factors and that the API Rate Model will require updates to reflect any changes to the placeholder values. The values in Tables 9a-9d are then used to index the re-allocated 2015 class revenue requirements from Table 8 to the proposed 2019 class revenue requirements shown in Tables 10a to 10d. *[Note – Tables 9d and 10d below has been updated from the 2019 IRM application to reflect the actual 2019 price cap adjustment factor of 1.5%].*

Table 9a

EB-2015-0051 Final Price Cap for 2016 Electricity Distribution Rates

Price Cap Metric	Status	Value
Inflation Factor	Final	2.10%
Productivity Factor	Final	0.00%
Stretch Factor	Assigned	0.60%
Price Index	Calculated	1.50%

Table 9b

EB-2016-0055 Final Price Cap for 2017 Electricity Distribution Rates

Price Cap Metric	Status	Value
Inflation Factor	Final	1.90%
Productivity Factor	Final	0.00%
Stretch Factor	Assigned	0.60%
Price Index	Calculated	1.30%

Table 9c

EB-2017-0025 Final Price Cap for 2018 Electricity Distribution Rates

Price Cap Metric	Status	Value
Inflation Factor	Final	1.20%
Productivity Factor	Final	0.00%
Stretch Factor	Assigned	0.60%
Price Index	Calculated	0.60%

Table 9d

EB-2018-0017 Final Price Cap for 2019 Electricity Distribution Rates

Price Cap Metric	Status	Value
Inflation Factor	Estimated	1.50%
Productivity Factor	Estimated	0.00%
Stretch Factor	Estimated	0.60%
Price Index	Calculated	0.90%

Table 10a

IRM Indexed Revenue Requirement for 2016 Using the Actual 2016 Price Cap			
Excluding Transformer Ownership Allowance			
Customer Class	**Revenues**		
	Fixed	**Variable**	**Total Revenue**
Residential - R1	2,162,028	13,680,810	15,842,838
Residential - R2	468,694	3,433,936	3,902,629
Seasonal	1,486,141	1,642,577	3,128,717
Street Lighting	24,445	259,794	284,239
	4,141,307	**19,017,116**	**23,158,423**

Table 10b

IRM Indexed Revenue Requirement for 2017 Using the Actual 2017 Price Cap			
Excluding Transformer Ownership Allowance			
Customer Class	**Revenues**		
	Fixed	**Variable**	**Total Revenue**
Residential - R1	2,190,134	13,858,661	16,048,795
Residential - R2	474,787	3,478,577	3,953,364
Seasonal	1,505,461	1,663,930	3,169,391
Street Lighting	24,762	263,171	287,934
	4,195,144	**19,264,339**	**23,459,483**

Table 10c

IRM Indexed Revenue Requirement for 2018 Using the Actual 2018 Price Cap			
Excluding Transformer Ownership Allowance			
Customer Class	**Revenues**		
	Fixed	**Variable**	**Total Revenue**
Residential - R1	2,203,369	13,942,408	16,145,778
Residential - R2	477,656	3,499,598	3,977,253
Seasonal	1,514,493	1,673,914	3,188,407
Street Lighting	24,837	263,965	288,802
	4,220,355	**19,379,884**	**23,600,240**

Table 10d

IRM Indexed Revenue Requirement for 2019 Using the Estimated 2019 Price Cap			
Excluding Transformer Ownership Allowance			
Customer Class	**Revenues**		
	Fixed	**Variable**	**Total Revenue**
Residential - R1	2,223,200	14,067,890	16,291,090
Residential - R2	481,955	3,531,094	4,013,049
Seasonal	1,528,124	1,688,979	3,217,103
Street Lighting	25,060	266,340	291,401
	4,258,339	**19,554,303**	**23,812,642**

7.0 – VECC –36
Reference: Exhibit 7, pages 6-7

a) What is the basis for the customer count and kWh/kW values used in Tables 3 & 4 and why are they the appropriate values to use?

RESPONSE:

a) The customer counts and load used in Tables 3 and 4 are the 2015 amounts approved in API's last cost of service application. They are the basis upon which API's 2019 rates and RRRP requirement were determined, following the determination of 2019 class-specific revenue requirements, as described in response to 7-VECC-35. The use of 2019 actual rates on Sheet I6.1 of the cost allocation model for the Seasonal and Street Lighting classes is consistent with the instructions in the model. The 2019 equivalent rates calculated for the R1 and R2 rate classes are the rates that would recover API's revenue requirement in the absence of RRRP funding. The use of equivalent rates for these classes on Sheet I6.1 of the cost allocation model results in realistic revenue-to-cost ratios by effectively allocating the revenue from RRRP funding between these two rate classes. This approach is consistent with API's prior cost of service applications.

7.0 – VECC –37

Reference: Exhibit 7, page 8 (lines 1-19)
Cost Allocation Model, I9 Direct Allocation Tab
Board Directions on Cost Allocation Methodology For Electricity Distributors (EB 2005 0317), page 31

Preamble: The Board Directions on Cost Allocation Methodology state: “Direct allocation must be applied if, and only if, 100% of the use of a clearly identifiable and significant distribution facility can be tracked directly to a single rate classification”.

a) Please explain the nature and use of the assets that Algoma proposes to directly allocate.

b) It is noted that in each case (per Tab I9) the asset/expense values are split between Residential and Street Lights. What is the basis for the split between customer classes?

c) Are all of the individual assets/expenses for which direct allocation is proposed used only by either the Residential or Street Light class or are some/all of the assets/expenses common to and shared by both classes as suggested at lines 23-26?

d) Please provide an alternative Cost Allocation Model where there is no direct allocation of the Dubreuil’s former assets/costs.

RESPONSE:

a) API proposes to directly allocate the costs of the assets that comprise the distribution system historically owned by Dubreuil Lumber Inc.

b) The basis for the split is an analysis of customer counts and load for the two classes, as detailed on pages 8-9 of Exhibit 7.

c) All of the assets and expenses are common to and shared by both classes.

d) Please see the response to 7-Staff-64.

7.0 – VECC –38
Reference: Exhibit 7, page 8 (lines 20-26)

a) How many months of demand history does Algoma have for Dubreuil's former large commercial/industrial customers?

b) If more than one year (12 months) of history now exists for any of these customers, is the average monthly demand for any of them over 50 kW? If yes, for how many customers is this the case?

RESPONSE:

a) API has no demand history for DLI's former large customers. These customers have historically been billed on an energy basis only. The majority of the associated metering installations were not capable of producing accurate demand reads due to the absence of a demand register and/or other issues with the meter installation.

b) N/A.

7.0 – VECC –39
Reference: Exhibit 7, page 10 (lines 7-17)
Cost Allocation Model, I4 BO Assets Tab

a) Please clarify precisely what assets Algoma considers to be “Bulk” and why. In providing the explanation please address separately: i) overhead facilities and ii) underground facilities.

b) Please explain how the 15% allocation bulk was established for each by type of asset (i.e., USOA 1830, 1835 and 1845).

c) Please explain how/why there are costs associated with underground conductor (USOA 1845) but not costs related to underground conduit (USOA 1840).

RESPONSE:

a) API considers its express feeders to be “Bulk” assets. The function of these circuits, which operate primarily at 34.5 and 44 kV, is to supply the peak demand of a number of distribution substations and a very small number of large industrial customers. In consideration of the relative distances and load, these assets were originally built as an efficient alternative to 115 kV transmission assets. API did not differentiate between overhead and underground in the categorization of bulk assets; a small portion of one express feeder is sub-marine cable by necessity due to an expansive water crossing.

b) For poles and overhead conductor, API established the allocation based on consideration of the number of kilometres of each asset, and cost estimates for each voltage level as follows:

O/H Category	km	$/km	Total Cost	% of Total
Primary	1638.8	78,000	127,826,400	75%
Bulk	196.3	130,000	25,519,000	15%
Secondary	307	55,000	16,885,000	10%
Total	**1835.1**		**170,230,400**	**100%**

API used a similar approach for underground conductor, estimating a cost for 14 km of primary underground conductor as shown in the table below. For bulk underground, the only asset is a single submarine cable crossing, and API therefore used the actual recent replacement cost for this asset. API does not own any secondary underground cable, however it does install and connect customer-supplied cable to its system at either a riser pole or a pad-mounted transformer. 1520 customers have an underground connection to API's system, and API estimated a cost of $250 (labour and connectors) for each connection point, for a total of $380,000.

U/G Category	km	$/km	Total Cost	% of Total
Primary	14	117,000	1,638,000	65%
Bulk	See explanation above		509,920	20%
Secondary	See explanation above		380,000	15%
Total	**14**		**2,527,920**	**100%**

API notes that the Secondary value of 15% was inadvertently input for the Bulk allocation (cell D51 on Sheet I4). This has been corrected in the cost allocation model filed in conjunction with these interrogatory responses (see 1-Staff-2 for details).

c) Cost of conduit is included in USOA 1845 with the associated underground conductor due to the relative immateriality of the cost of conduit and the limited amount of underground conductor in API's system. Underground conductor comprises a very small portion of API's asset base (<1%). Further, a portion of API's underground assets are either sub-marine or direct buried, and therefore do not have any conduit associated with the installation.

7.0 – VECC–40
Reference: Exhibit 7, page 10 (lines 18-20)

a) Does the updated value for km of road in service area reflect the inclusion of Dubreuil’s service area?

RESPONSE:

a) Yes.

7.0 – VECC–41

Reference: Exhibit 7, page 7 (Table 4) and page 11 (lines 3-5)
Cost Allocation Model, I6.1 Revenue Tab and
I6.2 Customer Data Tab

a) Please explain why, in theI6.2 Tab, the Secondary Customer Base value for Street Lights is set at 15.

b) Please explain why, in the I6.1 Tab, there is no value included for the Existing Distribution kWh Rate for the Seasonal Class per Table 4.

RESPONSE:

a) The customer base of 15 represents the number of Street Lighting accounts, consistent with the value of 15 used in the “Total Number of Customers” cell above.

b) Cell O34 on Tab I6.1 was locked, however API was able to enter the variable rate under “Additional Charges” in cell O37. The resulting total revenue in cell O39 is the same as if the variable rate had been entered in the locked cell.

7.0 – VECC –42
Reference: Exhibit 7, page 10 (lines 7-17) and 11-13
Cost Allocation Model, I8 Demand Data Tab

a) Were the demand allocators adjusted in order to account for the direct allocation of certain accounts to the Residential and Street Lights classes?

 i. If yes, what adjustments were made?

 ii. If no, why not and, in Algoma's view, should adjustments should be made?

RESPONSE:

a) Adjustments were implicitly made to the demand allocators during the process of adjusting the 2020 load forecast in consideration of API's acquisition of the customers in Dubreuilville (see page 26 of Exhibit 3) and subsequently scaling the 2004 load profiles for consistency with the 2020 load forecast (see Table 10 of Exhibit 7). As a result, the 2020 demand allocators reflect the shift in load from the single DLI R2 Customer Account to multiple Residential accounts and a Street Light account. The associated customer counts and load are the same basis upon which the direct allocation of certain costs was based (see response to 7-VECC-37).

8.0 RATE DESIGN (EXHIBIT 8)

8.0 –VECC - 43

Reference: Exhibit 8, page 9 (lines 4-11)

a) To be deemed to be receiving Residential Service must a customer meet both criteria (i) and (ii) or just one of the two criteria? If just one must be met please explain the use of the conjunction “and” at line 7.

RESPONSE:

a) These statements should be viewed as mutually exclusive definitions of services that fall within API’s residential rate classes. Definition i) is the historical definition of a residential service, whereas definition ii) identifies services that were historically considered general service, but are reclassified as residential pursuant to Regulation 445/07. API’s residential customer classes therefore include all customers meeting definition i) and all customers meeting definition ii).

8.0 –VECC -44
Reference: Exhibit 8, pages 11-12

a) When does Algoma expect the Board to determine the actual RRRP Adjustment Factor for 2020 electricity distribution rates?

RESPONSE:

a) On August 13, 2019, the OEB confirmed to API (with copies to all intervenors) that the actual RRRP Adjustment Factor for 2020 is 1.17%. Calculation details have been filed as "API_IRR_RRRP_2020.pdf". The revised RRRP adjustment factor has been incorporated in the Rate Design and Bill Impact models filed with these interrogatory responses.

8.0 –VECC -45

Reference: Exhibit 8, page 19 (lines 12-17)
Exhibit 7, pages 20-21

a) Please explain more fully why maintaining the current fixed to variable split of 64.09%/35.91% for the Seasonal rate class would result in a decrease to the Seasonal fixed rate (prior to the 2020 adjustment under the 13 Residential Rate Design Policy) when the proposed revenue from the Seasonal rate class is increasing from $2,757,773 based on current rates to $3,013,020 based on the proposed revenue to cost ratios?

RESPONSE:

a) The 2019 fixed rate of $54.75 is based on 2019 allocated revenue of $3,217,103, which originates from the 2015 OEB approved amount, adjusted by 2016-2019 approved changes to revenue-to-cost ratios and price-cap IR adjustments. Further, the 2015 Seasonal customer counts and load approved in API's 2015 cost of service application were used as the basis for determining rates during the 2016-2019 IRM period. The value of $2,757,773 stated in the question refers to the 2020 revenue that would result from applying 2019 rates to the 2020 load forecast. This amount is used for the purpose of determining 2020 revenue deficiency, but is not the basis upon which 2019 rates were determined. The revenue allocated to the Seasonal class for rate-setting purposes is therefore decreasing from $3,217,103 in 2019 to $3,013,020 in 2020. This decrease is a result of declining customer counts and load over the 2015-2019 period, resulting in a lower Seasonal customer count and load forecast being input in the 2020 cost allocation model as compared to 2015.

The following table compares the derivation of API's approved 2019 Seasonal rates with an alternative derivation of 2020 Seasonal rates where the fixed/variable split is unchanged from 2019, confirming that maintaining the 2019 fixed/variable split would result in a reduction to the fixed rate.

Calculation of Seasonal Rates

Year	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
2019 IRM	kWh	3138	7,731,414		64.09%	35.91%	54.75	0.1494	2,061,841	1,155,262	3,217,103
2020 Maintain F/V	kWh	2960	5,439,365		64.09%	35.91%	54.36	0.1989	1,931,045	1,081,975	3,013,020

8.0 –VECC- 46

Reference: Exhibit 8, pages 20-22
RTSR Work Form, Tab 4 – RRR Data and Tab 6 – Historical Wholesale

a) What is the basis (i.e., year) for the customer class consumption data entered in Tab 4?

b) What is the basis for the IESO billing data enter in Tab 6 and also used in Tabs 7 and 8?

c) If the basis (i.e. year used) is not the same please explain why this mismatch won't bias the calculation of the RTSRs.

d) Please provide a revised RTSR Work Form where the usage data used in Tab 4 is based on the same year as the billing unit data in Tab 6.

RESPONSE:

a) 2020 data was entered in Tab 4.

b) 2018 data was entered in Tab 6.

c) Tab 4 has been adjusted to reflect 2018 RRR such that the same year of data has been used in both Tabs 4 and 6. See d) below.

d) A revised RTSR Work Form has been submitted along with these IR responses.

8.0 –VECC - 47
Reference: Exhibit 8, pages 34-35

a) Algoma notes that 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. Please comment on the anticipated total bill impact in 2021 for the affected rate classes when this rate rider terminates.

b) Please comment on the merits of extending the disposition period for this account over more than one year so as to ameliorate the year to year swings in the total bill impact.

RESPONSE:

a) Following corrections to the DVA continuity schedule resulting from other interrogatory responses, the GA credit rate rider has been reduced. The revised bill impacts presented in response to 1-Staff-3 confirm that there are no longer large total bill decrease for non-RPP customers.

b) N/A, based on response to a) above.

9.0 DEFERRAL AND VARIANCE ACCOUNTS (EXHIBIT 9)

9.0 –VECC -48

Reference: Exhibit 9, page 17 & Exhibit 4, page 69

a) Is API seeking to dispose of either the interim Licence Deferral Account (ILDA) or the Integration Costs Deferral Account (TICDA) in this application and as contemplated in the Board's recent EB-2018-0271 Decision?

b) Please provide the current balance of each account.

RESPONSE:

a) API is proposing to transfer amounts related dispose of the TICDA balance by amortizing the balance over the 2020-2024 period, consistent with the treatment of other one-time costs, as described in Section 1.3.7 of Exhibit 1 and Section 4.6.2 of Exhibit 4.

This disposition request includes current and forecasted transaction costs, as well as the transfer of one-time costs and 50% of 2017 OM&A costs from the ILDA to the TICDA. Please see the response to 1-SEC-10(c), and related attachments, for further detail on the rationale and relevant sections of the MAAD application.

API is further proposing to transfer the net book value of the 2017-2019 investments in the DLI system into its rate base in 2020, as described in Section 1.3.7 of Exhibit 1 and Section 2.5.6 of Exhibit 2.

A rate rider applicable to the former DLI customers was established in EB-2018-0271 for the disposition of the forecasted remaining balance in the ILDA.

b) Please see response to 4-Staff-57(b).