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| **Ontario Energy** **Board** P.O. Box 231927th Floor2300 Yonge StreetToronto ON M4P 1E4Telephone: 416- 481-1967Facsimile: 416- 440-7656Toll free: 1-888-632-6273 | **Commission de l’énergie****de l’Ontario**C.P. 231927e étage 2300, rue YongeToronto ON M4P 1E4Téléphone: 416- 481-1967Télécopieur: 416- 440-7656Numéro sans frais: 1-888-632-6273 |  |

**BY E-MAIL**

July 24, 2019

Kirsten Walli

Board Secretary

Ontario Energy Board

2300 Yonge Street, 27th Floor

Toronto, ON M4P 1E4

Dear Ms. Walli:

**Re: Algoma Power Inc. (Algoma Power)**

**2020 Cost of Service Appliaction**

**OEB File Number EB-2019-0019**

**OEB Staff Interrogatories**

In accordance with Procedural Order No. 1, please find attached OEB staff’s interrogatories in the above noted proceeding. Algoma Power and all intervenors have been copied on this filing.

Algoma Powers’ responses to interrogatories are due by August 14, 2019.

Yours truly,

*Original Signed By*

Birgit Armstrong

Project Advisor, Major Applications

Attach.

**OEB Staff Interrogatories**

**2020 Cost of Service Rate Application**

**Algoma Power Inc. (API)**

**EB-2019-0019**

**July 24, 2019**

**Exhibit 1**

**1-Staff-1**

Following publication of the Notice of Application, has API received any letters of

comment in respect of this application?

1. 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.

1. 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.

**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.

**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.).

**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:

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

**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:

1. 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.
2. 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.

**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

**2-Staff-7**

**Ref: Exhibit 2 / DSP / p.108**

Questions:

1. Please explain System Renewal forecasted investment spikes in 2020 and 2023?
2. Please explain the System Service actual investment spike in 2019?

**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:

1. 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.
2. What is the reason for a significant actual winter and summer peak load increase in 2018 over the previous years?

**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:

1. Please explain what you mean by “continued integration” of the existing business system and what are the associated costs?
2. 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?

**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:

1. Please provide measures and metrics for customer oriented performance, such as customer bill impact and power quality (not service quality)
2. 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
3. Please provide information regarding system line losses

**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.

**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?

**2-Stff-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:

1. Do capital and inspections plans presented in the DSP address only API owned poles or also include joint use poles owned by third parties?
2. 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?

**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?

**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:

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

**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.

**2-Staff-17**

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

Questions:

1. Please confirm that no Heath Index distribution was provided for overhead switches and reclosures due to the lack of condition data.
2. 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.

**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:

1. What is the correct number of station power transformers for which a Health Index was calculated?
2. What is the correct number of spares and voltage regulating transformers for which a Health Index was calculated?
3. What is the correct number of ratio banks for which a Health Index was calculated?

**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?

**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:

1. Please indicate what API’s final capital contribution amount is expected to be?
2. 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?
3. What are the costs of other alternatives being considered, e.g. reinforcement of the feeder NA1?

**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:

1. 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.
2. Provide further justification of the delay for this project, initially planned in 2017.
3. Please explain the increased cost estimate for this transformer over a three year period.

**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?

**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:

1. 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?
2. 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.

**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

**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:

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

**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?

**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)?

**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?

**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:

1. Please provide a copy of the Applicant’s formal business case for the new facility and provide the proposed location of the facility.
2. Please provide a copy of all materials provided to the applicant’s Board of Directors in approving the proposed Facility in Sault Ste. Marie.
3. 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.
4. 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.

**2-Staff-30**

**Ref: Exhibit 2 / DSP / pp. 149 - 151**

 **Exhibit 2 / Appendix M**

Questions:

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

**2-Staff-31**

**Ref: Exhibit 2 / DSP / pp. 142 -143**

**Exhibit 2 / DSP / pp. 149 – 151**

Questions:

1. 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.
2. Provide a calculation of the rate riders for the non-RRRP eligible rate classes and estimated bill impacts.

**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.

**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.



Questions:

1. 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.

**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.

**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.

**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.

**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:

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

**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:

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

**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.

**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:

1. 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
2. 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.
3. Please explain why a full year of 2020 CDM program delivery was used when only half of the savings would be realized in 2020.
4. 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.
5. 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.
6. Please re-file all relevant tables and supporting documentation to show the changes and impact on the load forecast.
7. 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.

**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:

1. Please confirm OEB staff’s calculation or provide a derivation of the 15,332 kW adjustment.
2. If 2017 savings were used in the CDM adjustment, please provide the rationale
3. Please provide a breakout of forecasted CDM program demand savings in 2018, 2019, and 2020.
4. 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.

**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.

**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.

**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:

1. Please confirm that the remaining cost driver in the amount of $78k is due to overhead lines and feeders maintenance in the Dubreuilville area.
2. 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.
3. 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.

**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:

1. Confirm that both requests are driven by the expiry of the existing lease at 2 Sackville Rd. in Sault Ste. Marie.
2. Has API signed the new lease for the 2 Sackville Rd. facility? If not, please provide a status update.
3. Has API received any quotes for an alternate location?
4. 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?

**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.

**4-Staff-47 Shared Services**

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

Questions:

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

**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?

**4-Staff-49 Corporate Cost allocation**

**Ref: Exhibit 4 / s. 4.5**

 **Appendix 2-N**

Questions:

1. 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.
2. 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.
3. 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.
4. Please explain any variances or the absence of variances.

**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:

1. 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.
2. 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.
3. Please elaborate on how charges would be allocated “based on assets and share purchase plan participants” as referenced in the above quotation.
4. Please elaborate on what is meant by “cost-based pricing” in the above paragraph and how it is determined.

**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:

1. Please provide further detail as to the nature of these costs and confirm that they are distinct and incremental.
2. Please explain why 35% of shared IT cost are allocated to API versus 25% of administrative services.
3. 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?

**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:

1. Please specify API’s share of the corporate cost attributed to enhancing cyber security measures as per the Ontario Cyber Security Framework.
2. Please specify the corporate cost allocated for the MSSP that was allocated to API.
3. Does API and/or its affiliates conduct annual risk reviews? If so, are these costs included in corporate costs allocated to API?
4. 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.
5. Which range of technology services are being provided as part of this allocation.
6. Please provide the type of training provided to staff each year for cyber security and highlight the corporate cost allocation for staff.
7. Is the cyber security infrastructure on-site or cloud based?
8. Is this material summarized and reported to its Board of Directors and approved to address identified cyber security risks?

**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:

1. How does API plan to fulfill the above shown vegetation management program following the departure of a key contractor in the area.
2. 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.
3. Provide the unit cost identified through the request for proposal and compare to historic unit cost.
4. Compare 3rd party costs against internal labour costs.

**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:

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

**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.

**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:

1. 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.
2. 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.
3. If not discussed in the response to part b, please state how compensation has been aligned to performance expectations for management and other employees.

**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:



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:

1. 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.
2. 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.
3. 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.
4. 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.
5. 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.
	1. 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.
	2. 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?
	3. 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.

**4-Staff-58**

**Ref: Exhibit 4 / s. 4.9.1 Overview of PILs**

**Exhibit 4 / s 4.9.2 Accelerated CCA**

Questions:

1. Please provide a copy of the following schedules from API’s 2018 Corporate Tax Return:
	1. Schedule 1 (Net Income (Loss) for Income Tax Purposes)
	2. Schedule 2 (Charitable Donations and Gifts)
	3. Schedule 4 (Corporation Loss Continuity and Application)
	4. Schedule 8 (Capital Cost Allowance (CCA))
	5. Schedule 13 (Continuity of Reserves)
2. 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.
3. Please repopulate the test year CCA calculated using the format provided for in the 2020 OEB PILs model.
4. Please prepare an analysis showing the impact that the Accelerated CCA program will have on calculated PILs from 2020 to 2024.
5. 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.

**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:

1. 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).
2. 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.
3. 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.

**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:

1. 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?
2. Please explain the reason for API’s proposed adjustment, specifically:
	1. 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.
	2. Why it is appropriate to revise the IESO’s estimate of net verified peak savings?
	3. 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).
3. 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.
	1. If yes, please file the correspondence from the IESO in response to this interrogatory.
	2. If no, please undertake to ask the IESO on the appropriateness of such an approach, and file the response.
4. Please discuss why an adjustment to the demand savings in 2014 and prior years was not required.
5. 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.
6. 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:
	1. Adjusting the R2 class billed consumption data for free ridership. What is the assumption applied, if any, and what is that based on?
	2. 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?
7. 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.

**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:

1. Please confirm that the kWh reductions to street light savings were applied against the Efficiency: Equipment Replacement Incentive Initiative (EERI) program.
2. 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.

1. 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.
2. Please explain why the adjustment is not required for 2014 and prior years.
3. Please quantify how much lost revenue API is foregoing, had it not reduced savings by the proposed adjustments.

**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.

**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:

1. 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
1. 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).
2. Please confirm any changes to the LRAMVA workform in response to these LRAMVA interrogatories in “Table A-2. Updates to LRAMVA Disposition (Tab 2)”.

**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?

**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:

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

**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.

**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:

1. 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.
2. Please provide the rates that would result from applying the residential rate design policy to the rates derived in part a)
3. 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.

**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.

**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:



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



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:

1. 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
2. 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.

**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:

1. 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?
2. 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.
3. 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.

**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.

**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:

1. 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?
2. Please explain what is meant by overstatement of current year Q4 RPP Settlement true-up. What specifically was overstated?
3. 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.

**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]](#footnote-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:

1. 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).
2. 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.
3. 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.
4. 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).
5. 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.
6. 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).

**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.

**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:

1. 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.
2. 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?
3. 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.
4. 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?

**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)[[2]](#footnote-2)**

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:

1. 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.
2. 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.
3. 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.
4. 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.
5. 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?

**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:[[3]](#footnote-3)



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:

1. Please confirm or correct this table.
2. 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?
3. 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.
4. 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.
5. 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.

1. [EB-2013-0368 Decision and Order](http://www.rds.oeb.ca/HPECMWebDrawer/Record/422238/File/document) [↑](#footnote-ref-1)
2. [Decision and Order (EB-2015-0304)](https://www.oeb.ca/sites/default/files/Dec-Order-ERSC-20190214.pdf) [↑](#footnote-ref-2)
3. Exhibit F/Tab 3/Schedule 1/p. 2 [↑](#footnote-ref-3)