OEB Staff Interrogatories
2019 Cost of Service Rate Application
Energy+ Inc. (Energy+)
EB-2018-0028
August 15, 2018

Exhibit 1 – Administration

1-Staff-1

Responses to Letters of Comment

Following publication of the Notice of Application, the OEB received six letter(s) of comment. Sections 2.1.6 of the Filing Requirements state that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the Board related to the distributor's application. If the applicant has not received a copy of the letters or comments received at the community meetings, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

1-Staff-2

Updated RRWF

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated Revenue Requirement Work Form (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: Section 1.3 Customer Engagement

Energy+ Inc. (Energy+) consulted all customer classes during the augmented customer engagement process. In total, 1,582 of 64,856 customers (approximately 2.5% of the customer base) participated in the activities undertaken in 2017 and early 2018.

Table 1-28 summarizes the scope of the various customer engagement activities and valid completes.

a) Please explain how residential and general service <50kW customers were selected in the online workbook portal and random telephone survey activities.
b) Please specify, among the valid completes shown in Table 1-28, how many residential/general service <50kW customers are from the former Cambridge and North Dumfries Hydro Inc. (CND) service territory and how many customers are from the former Brant County Power Inc. (BCP) service territory.
c) Please explain what opportunities were identified that lead to the $292,000 reduction in departmental budget requests for 2019 OM&A expenditures compared with the initial budget.

1-Staff-5

Ref: Exhibit 1, page 88 of 1145

With respect to system access investments, Energy+ states that it has a detailed Economic Evaluation Policy, with specific costing parameters to ensure the incremental costs of these projects are fairly allocated between the initiator and the customer base, over time based on load forecasts and other factors.

a) Please describe Energy+'s Economic Evaluation Policy and explain how Energy+ ensures the incremental costs of these projects are fairly allocated between the initiator and the customer base.

1-Staff-6

Ref: Section 1.5 Business Plan Highlights

Energy+ states that the action items and initiatives developed in the business planning process set the foundation for the development of the department business plans and 2018 and 2019 operating and capital budgets that underpin this application.

a) Please provide all the communication between Energy+, its Board of Directors and its shareholder from 2016 to 2018, including presentations from Energy+ to its Board regarding capital investments and OM&A. Please explain how spending priorities were arrived at.

1-Staff-7

Ref: Section 1.6 Performance and Benchmarking

Energy+ has benchmarked performance both internally and externally.

For internal benchmarking, Energy+ summarized additional performance measures used to monitor continuous improvements that are divided into three categories of customer-oriented performance, cost efficiency and effectiveness, and asset/system operations performance in Table 1-40A (Exhibit 1, page 141 of 1145).

For external benchmarking, performance comparisons were made to peer distributors.

The PEG model was used to forecast the cohort group for the 2018 bridge and 2019 test years.

a) Please provide Energy+ data for metrics listed in Table 1-40A for 2016 and 2017, if available.
b) If any measures are currently outside the desired outcome, please discuss Energy+'s plan to improve its performance.
c) Please explain how PEG model was used in finalizing the proposed operating and capital plans incorporated into this application.

1-Staff-8

Ref: Section 1.6.4.2 Other Key Cost Metrics – Peer Comparison

Table 1-43 summarizes the 2016 OM&A costs for Energy+ compared to its peers based on information from the 2016 OEB yearbook.

Table 1-43: 2016 OM&A Costs - Energy+ Comparison to Peers

	Energy +	Guelph	Waterloo North	Brantford	Kitchener-Wilmot
OM&A Costs					
O&M	$5,605,598	$6,298,956	$7,546,787	$3,500,830	$9,498,133
Admin Expenses	$11,551,476	$8,165,041	$5,746,284	$6,917,503	$8,006,372
Total Recoverable OM&A	$17,157,075	$14,463,997	$13,293,071	$10,418,333	$17,504,505
Number of Customers	63,651	54,414	56,230	39,405	94,058
Number of FTEs	126	124	136	57	187
Customers/FTEs	505	439	413	691	503
OM&A cost per customer					
O&M per customer	$88.07	$115.76	$134.21	$88.84	$100.98
Admin per customer	$181.48	$150.05	$102.19	$175.55	$85.12
Total OM&A per customer	$269.55	$265.81	$236.41	$264.39	$186.10
OM&A cost per FTE					
O&M per FTE	$44,488.88	$50,798.03	$55,491.08	$61,418.07	$50,792.16
Admin per FTE	$91,678.38	$65,847.10	$42,252.09	$121,359.70	$42,814.82
Total OM&A per FTE	$136,167.26	$116,645.14	$97,743.17	$182,777.77	$93,606.98

a) Please update Table 1-43 using information provided from the 2017 OEB yearbook.
b) The 2016 data shows that Energy+'s total OM&A per customer is higher than comparators; please discuss any higher level of services that customers received for the relatively higher costs.

1-Staff-9

Ref: 2019 CoS Models update

On July 12, 2018, the OEB has issued updated versions of the Chapter 2 Appendices and Models for 2019 rate applications. Please provide updated version of the following models/tabs:

a) Please update Chapter 2 Appendices as follows:
   i. Worksheet 2-Z, Commodity Expense is new.
   ii. Worksheet 2-M is modified to separate ongoing regulatory costs and one-tome regulatory costs
b) Please file Chapter 5 Appendix.

1-Staff-10

Ref: 2017 Actuals

Energy+ provided 2017 forecast data instead of 2017 actuals in various Exhibits throughout the application. Please update the 2017 forecast for the actuals for the following documents:

a) Please update 2017 OM&A expenditures to the actuals.
b) Please update 2017 capital expenditures to the actuals (e.g. App. 2-AB)
c) Please update Table 1-40C Energy+ Scorecard with 2017 actual data.

Exhibit 2 – Rate Base

2-Staff-11

Ref: DSP, Appendix N, Facilities Business Plan – CND

Tables 3 and 4 in the Facilities Business Plan summarize the current and proposed facilities space. The current administration space is approximately 18,000 square feet (Bishop Street and Thompson Drive) while the proposed administration space is about 35,000 square feet (Southworks and Bishop Street).

Energy+ states that staffing levels are projected to be fairly similar to current levels over the next 5 years.

a) Please confirm the proposed administration space is about 35,000 square feet (Southworks and Bishop Street facilities)
b) Please explain why a 94% increase in administration space is required considering that staffing levels are projected to be fairly similar to the current level.

2-Staff-12

Ref: DSP, Appendix N, Facilities Business Plan – CND

Energy+ is currently operating two facilities in the CND service territory, which are the Bishop Street facility (53,100 square feet) and the Thompson Drive facility (5,147 square feet). Energy+ states that the Bishop Street facility is 12 years past its intended 25-year lifespan and housing additional administrative staff in the Thompson Drive facility has resulted in physical separation with the rest of the organization.

In 2014, the former CND engaged an architect on contract to undertake a space needs analysis and explore options for meeting CND's long term facility requirements. The analysis identified a preferred option being the construction of a new facility and subsequent sale of the Bishop Street Building.

In November 2014, Regional Appraisers Inc. determined that the Bishop Street Building had a value of $4.0 million.

In 2016, Energy+ was approached by a developer of a significant mixed-use condo / office / retail project in downtown Cambridge (known as the Gaslight District). The developer offered to "gift" approximately 21,500 square feet of space in an existing heritage building if Energy+ would undertake renovations to convert it into suitable office space (the Southworks Facility).

Energy+ conducted analysis of this opportunity to determine the feasibility of this alternative compared to the other options explored. Energy+ proposes to relocate all administrative departments to the Southworks Facility, terminating the lease of 5,147 square feet at the Thompson Drive Building, and renovating a portion of the Bishop Street Building to enable it to accommodate engineering, metering, system control room, and operations.

The $4.5 million renovation cost plus an additional $0.5 million for office furniture and equipment in 2020 is the subject of the ACM proposal.

a) Please explain how the 21,500 square feet of space in the Southworks Facility was determined.
b) Please confirm Energy+ owns the Southworks Facility.
c) Please provide a copy of the Purchase and Sale Agreement between Energy+ and the developer.
d) Please provide the architectural drawing for the existing heritage building (site and floor).
e) Please provide the proposed architectural drawing of site plan and floor plan for the Southworks Facility.
f) Please provide the project schedule for the Southworks Facility.
g) Please confirm that an annual $150,000 fee is required for parking at the Southworks Facility.
h) Please discuss if Energy+ has considered an option of renovating the Southworks Facility to a combined administrative office and operation center, and selling the Bishop Street Building.
    i. If so, please explain why Energy+ decided not to go with this option.
    ii. If not, please do a cost estimate for this option.
i) Please provide the assumptions, analysis and calculations used to arrive at the estimated cost of $4,145,500 (excluding HST) to make 21,892 square feet of space suitable to be an administrative office for Energy+ (estimated by Melloul-Blamey on March 9, 2017).
j) Please provide a breakdown of the $0.5 million budget for the cost of IT system, furniture, and any unforeseen heritage site modification.
k) Please discuss the accuracy of the estimated renovation cost and discuss Energy+'s plan to mitigate any risks.
l) Please discuss if Energy+ has considered/will consider renting out the administration space of the Bishop Street building if all administrative staff were located to the Southworks Facility.

2-Staff-13

Ref: DSP, Appendix N, Facilities Business Plan – CND

Energy+ stated that "Separation of administrative offices from the operations facility provides greater efficiency and utilization of space in the event of any future mergers or acquisitions."

a) Please identify any future mergers or acquisition opportunities.
b) Please explain why the separation provides greater efficiency and utilization of space.

2-Staff-14

Ref: ACM Model

a) Please reconcile 2019 revenue requirement from distribution rates in tab 6 of the ACM model with RRWF workform tab 9.
b) Please reconcile 2017 distribution revenue in tab 7 of the ACM model with Exhibit 3, Table 3-38.

2-Staff-15

Ref: DSP, Appendix N, Facilities Business Plan – Brant

Currently, there is one facility in the Brant service territory, which is the Dundas Street Facility. It is comprised of approximately 5,000 sq.ft of administrative space and 9,400 sq. ft of operations space. Energy+ states that the facility is in need of refurbishing, as there have been no significant investments made to the building since it was first constructed.

In November 2014, at the time of the acquisition of the former BCP, there were approximately 27 employees, including 15 administrative personnel and 12 operations and field personnel located at the Dundas Street Facility. Following the acquisition and restructuring of the organization, administrative staff were relocated to the Bishop Street Building or the Thompson Drive Building. Currently, there are 13 operations staff, supporting the Brant County service area, that continue to be located at the Dundas Street Facility. With the relocation and centralization of administrative staff following the acquisition, the office space is currently vacant and underutilized, whereas the operations space is over-crowded.

After considering three options, Energy+ sold Dundas Street Facility for $1.5 million in a sale-leaseback transaction on April 3, 2018 and will enter into a 20-year lease with BPI at its Garden Avenue facility.

The 2019 test year includes a $4.4 million capital cost related to this capital lease.

a) Please provide any space need analysis which has been done for the Dundas Street Facility.
b) Please provide a copy of the Purchase and Sale Agreement of the sale-leaseback transaction.
c) Please clarify whether or not the assets related to Dundas Street Facility has been removed from Energy+'s rate base proposed for 2019.
d) Please provide a detailed cost estimate (cost per square feet and total capital expenditures) for option 1 – renovate or rebuild existing Dundas Street Facility, including all the assumptions, analysis and calculations.
e) Please provide the architectural drawing of site plan and floor plan for the Garden Avenue facility, indicating Energy+'s exclusive space and shared space with BPI.
f) Please provide the project schedule for the Garden Avenue facility.
g) Please provide a copy of the Shared Services Agreement with BPI.
h) Please provide an Excel spreadsheet to show the assumptions, analysis and calculations used to arrive at the estimated cost of $20/s.f./year of base rent and $12.50/s.f/year rent for shared space with BPI.
i) Please show the calculations to arrive at the estimated capital lease cost of $4.4 million.
j) Please identify factors that lead to the +/- 30% uncertainty of the cost estimate.
k) Please discuss Energy+'s plan to mitigate the risks of uncertainty in cost estimate for each factor identified in j.
l) What is the typical travel time between the two proposed Operations Centres?

m) Did Energy+ review the option of servicing its entire service territory from the new BPI facility (i.e. Garden Avenue) and what would be the principle drawbacks of consolidating operations at the single facility?

2-Staff-16

Ref: DSP, Appendix N, Facilities Business Plan – Brant

Energy+ states that "There will be significant efficiencies gained by drawing from a single inventory pool, yard, fueling station, and tower that will be shared and can service both Energy+ and BPI."

a) Please provide an estimate of expected savings (both operating and capital costs) by sharing the costs of facilities and services with BPI for the next 5 years.

2-Staff-17

Ref: Exhibit 2, page 108, 207-210

Energy+ states that in the Brant area, HONI owns the shared feeders in Energy+'s service area.

a) How many shared feeders are owned by HONI?
b) What is the total circuit length of the feeders owned by HONI?
c) How many poles are part of these shared feeders?
d) Please confirm that HONI is responsible for assessing the condition of the poles supporting the shared feeders and eventual replacement of these poles at end of life.

2-Staff-18

Ref: Exhibit 2, pages 108, 113, 121

Energy+ states that the ownership of Powerline MTS is shared between Energy+ and BPI. Energy+ also states that MTS equipment renewal at MTS #1 and Powerline MTS includes replacement of relays and electronics. Energy+ and BPI have hired an engineering firm (IBI Group) to make recommendations after a full review of the complete dc system at Powerline MTS.

a) How are station capital, operating and maintenance costs split between Energy+ and BPI?

2-Staff-19

Ref: Exhibit 2, page 114, 115, 122, 123, 218-219, 266

Table 2-1 presents the capital expenditures by investment category and the system operations and maintenance (O&M) costs for both the historical and forecast period. Energy+ states that reduction in third-party infrastructure development requirements is also responsible for the reduced capital contributions budgeted over the forecast period, there are no large relocation projects in the period from 2019 to 2023 and new residential subdivision servicing activities were significantly higher over the historical period compared to the test year. Energy+ has reduced its forecast of subdivision lots compared to historical period development. Energy+ states that the annual average forecast System Access spend, net of capital contributions, is $3,384,253.

a) Please explain any net increases in 2019 system access investment spending compared to net 2018 system access investment spending in light of the statements above indicating less relocation and subdivision activity in the test year and following forecast period.
b) Please confirm that the statement on page 266 “Forecast system access investments over the forecast period are, on average, 24% less than the historical period spending.” is based on capital spending excluding the impact of capital contributions.
c) Please confirm that forecast system access investments over the forecast period are on average 5% higher than the historical period spending when the effects of capital contributions are taken into account.

2-Staff-20

Ref: Exhibit 2, page 116, 162, 214, 272, 337

Energy+ states that it is reviewing various options for cable injection and cable testing to improve the efficacy of its underground rebuild programs. Energy+ states that it has not seen a significant number of cable failures.

a) Please provide timelines for Energy+’s review of options.

b) On p. 337 of the DSP, Energy+ states that "Replacement of the underground primary cable provides a better long-term result than injection". Please provide the analysis that resulted in this conclusion.

2-Staff-21

Ref: Exhibit 2, page 117

Energy+ states that the 2016 merger between BCP and CND would result in reductions in capital expenditures of $0.2 to $0.3 million per year.

a) Please detail the specific capital expenditure savings obtained since the merger.

2-Staff-22

Ref: Exhibit 2, page 120, 216, 247-249

Energy+ states that it uses the Kinectrics PROSORT tool for prioritization of investment across asset categories and investment portfolios based on Energy+'s Business Values and their attributes. Energy+ states that this analysis will be performed annually.

a) Please provide specific examples of the use of the PROSORT tool for each of the four investment categories.
b) What is the specific linkage between the Asset Management Objectives and the Business Values?
c) How are the Business Values and Asset Management Objectives incorporated into the Risk Matrix?
d) In Figure 4-11 please identify the specific Risk Matrix Consequence Assessment for each of the Business Value categories.
e) Has Energy+ reanalyzed projects using the PROSORT tool in 2018? If so, please provide information with respect to changes in projects, project ranking and prioritization.

2-Staff-23

Ref: Exhibit 2, pages 120, 138-140, 145, 214

Energy+ states that it is shifting the tree trimming cycle in BCP from a five year cycle to a four year cycle in 2020. Based on information provided in Tables 2-6 and 2-7, tree contacts are the third highest cause of outages on Energy+'s system.

a) Please provide the incremental annual cost for tree trimming work in BCP based on the four year cycle proposed.
b) Please provide forecast estimates for customer interruptions and customer hours of interruption due to Code 3 – Tree Contacts based on the amended tree trimming program.
c) How many tree contact outages during the historical period were due to "danger" trees outside the normal trim zone?
d) Please advise what other changes, if any, to the tree trimming program Energy+ plans to undertake to reduce future customer interruptions due to Code 3 events.

2-Staff-24

Ref: Exhibit 2, page 128, 217-218

Energy+ states that a new TS (designated as MTS #2) is expected to be required in the Cambridge area outside of the forecast period of this DSP. Energy+ has started to acquire land and begin the engineering/environment assessment process for the siting of MTS #2, but has otherwise not budgeted for any related capital expenditures. No costs related to MTS #2 are proposed to be included in test year rates.

a) Please confirm that the IESO, as part of the Regional Planning process, has issued a letter to Energy + confirming the need for the station and recommending that Energy+ proceed with the work leading to the implementation of a new transformer station.
    i. Please provide a copy of the letter.
b) Is it the intention of Energy+ to recover the above noted costs at a future Cost of Service application?
c) As capacity is available at Galt TS and MTS#1, what is Energy+'s planning position on the maximum length for 4 circuit pole lines.

2-Staff-25

Ref: Exhibit 2, page 129-130

Energy+ states that it has entered into a Cost Recovery Agreement (CCRA) with HONI for the Brant TS 115-kV switching facilities in April 2017. The CCRA represents approximately a $5.67M cost recovery commitment to HONI. The new incremental load is forecast to be 21.7 MW after the tenth (10th) anniversary of the project in service date.

a) What is the average annual load growth rate used by Energy+ for the first 10 years of the CCRA true-up period?
b) Please advise in what anniversary year, based on Energy+ load forecasts and guarantees in the CCRA, HONI will have recovered their costs from Energy+ load growth.

2-Staff-26

Ref: Exhibit 2, pages 132

Energy+ states that system reliability metrics are tracked as per the OEB Reporting & Record Keeping Requirements (RRR) dated May 3, 2016. The current version of the OEB RRRs are dated March 15, 2018.

a) Please advise if the updated version of the reporting requirements has any impacts on the performance metrics presented in this DSP.

2-Staff-27

Ref: Exhibit 2, pages 153-154, 253

Energy+ states that, in consideration of feedback from customer consultations, limits have been proposed on capital spending to keep rates reasonable and projects are prioritized within this budget constraint. Table 4-34 presents the imposed limits on distribution capital expenditures based on customer feedback, which was $10 million in the bridge year and is proposed to be $10 million in the test year and $12 million each year of the forecast period thereafter.

a) How were the capital limits that were presented to the customers arrived at?
b) While Table 4-34 states that forecast capital expenditure is less than the imposed limit, Table 2-1, Fig. 4-2 and Table 4-42 show forecast spending in excess of this limit. Please explain.

2-Staff-28

Ref: Exhibit 2, page 154

Energy+ states that it has a “Priority One” telephone line that will be further shared with the key customers that have time-sensitive processes and require immediate information regarding outages and restoration times. The “Priority One” line elevates the call to the front of the telephone queue for “improved response times”.

a) Please provide a list of “key customers” that this applies to.
b) Is Energy+ proposing a higher level of service (compared to other customers of the same rate class) for these key customers that will be put at the front of the line for service restoration?
c) Will these key customers get service restoration precedence over critical loads that may be present in the Energy+ service area?

2-Staff-29

Ref: Exhibit 2, page 162

Energy+ states that it has experienced a low level of growth in its CND service territory over the past five (5) years, both in terms of number of customers and kilometers of lines. Energy+ also states that the cost per customer and cost per kilometre of line have increased year over year with the increase in operating and capital expenditures. Energy+ also states that utilities with low growth rates with upward cost pressures experience higher increases in cost per customer and cost per kilometre of line as compared to utilities with higher growth rates that are able to fund capital renewal and operating costs through customer growth.

a) If Energy+’s growth was high, would it be Energy+’s intention to defer the needs of asset replacement as capital renewal and operating costs can be funded through customer growth?

2-Staff-30

Ref: Exhibit 2, page 162, 166-167, 180, 200-205

Energy+ states that the Flagged for Action (FFA) plan in the ACA has identified 39 km of single phase underground cable for replacement between the years 2018 and 2023. Energy+ plans to replace 48% of the FFA plan for single-phase underground cables and approximately 6% of the FFA plan for three-phase underground cable over the years 2018 through 2023. This works out to approximately 19 km of cable to be replaced over the years 2018 through 2023. Energy+ also states that it has not seen a significant number of cable failures in recent years. The underground system has performed reliably over the years; cable faults are extremely rare. The biggest cause of failure on the underground system is typically near primary elbow connectors. Cable "condition" is based on age of installation only. FFA identified underground cables are primarily replaced through Underground Rebuild projects.

a) Energy+ data shows that primary cable failures amounted to only 2.1%/3.5% (BCP/CND) of customer interruption hours over the historical period. Considering this low level of failure, why would Energy+ not consider delaying the start of cable replacement program until cable testing and cable injection options have been reviewed and put in place?
b) Why does Energy+ consider the physical characteristics of its cable, with low failure rates, equivalent to the physical characteristics of other LCD's cables of similar age but with much higher failure rates?
c) What is the failure mechanism related to the primary elbow connectors?

2-Staff-31

Ref: Exhibit 2, page 166-167, 190-192

Energy+ states that the FFA plan in the ACA has identified 2091 poles requiring replacement between the years 2018 and 2023. Of these, only 743 poles are considered to be in "poor" or "very poor" condition. Energy+ is targeting the replacement of 78% of FFA poles (1660) over the years 2018 through 2023. Energy+ also states that FFA poles are also replaced through Energy+'s Pole Replacement Program and planned Overhead Rebuild and Conversions. All of the FFA concrete poles were assessed to be in "good" or "very good" condition

a) How many FFA wood poles are expected to be replaced over the forecast period due to:
    i. System Access projects
    ii. Energy+'s Pole Replacement Program
    iii. Overhead rebuilds and conversions
b) For the poles identified in a) above, please indicate the number of "poor" and "very poor" in each of the three categories.

c) How many FFA concrete poles are expected to be replaced over the forecast period due to:
   i. System Access projects
   ii. Energy+'s Pole Replacement Program
   iii. Overhead rebuilds and conversions

d) Why are 24 concrete poles budgeted for replacement versus 18 in the FFA plan?

2-Staff-32

Ref: Exhibit 2, pages 173

Energy+ states that IT priorities are set based on short-term and long-term operational requirements of the business.

a) Please provide the most recent version of the IT Business Plan.

2-Staff-33

Ref: Exhibit 2, page 173, 242

Energy+ states that it stores data on its distribution assets in the GIS database. This process is currently being updated with an electronic process where inspection information will be captured electronically through the use of a tablet and the data will be converted and pushed into the GIS database for immediate update.

a) What quality control measures has Energy+ enacted to ensure the integrity and accuracy of date entered into the GIS from multiple sources?

2-Staff-34

Ref: Exhibit 2, pages 179

Energy+ states that replacement of poles drive the annual work program for overhead line crews while underground primary cable replacements drive the annual work program for underground crews and a balance of both overhead and underground work is necessary to maximize productivity of resources and utilization of equipment.

a) Does this imply that some programs are selected for implementation to ensure that some specific segments of Energy+'s workforce have something to do?

b) Does the annual budget envelope distinguish between available man hours of different areas of the workforce?

2-Staff-35

Ref: Exhibit 2, pages 180

Energy+ states that the overhead line rebuild and conversion program will extend over a period of nine (9) years, from 2017 through 2025, for an average of 18 km of line segment replaced per year. A fifteen-year plan would increase the cost of pole replacements over the longer term.

a) What is the incremental cost if the program was extended over a fifteen year period instead of the nine year period proposed?

2-Staff-36

Ref: Exhibit 2, page 186, 212

Energy+ states that the FFA plan recommended renewal for nine (9) overhead switches over the forecast period and Energy+ is planning to replace eight (8) of these switches through its overhead rebuild programs and load-break switch replacement program. All the overhead switches are considered to be in “good” or “very good” condition.

a) Please confirm that switches replaced as part of the overhead rebuild program are 8kV rated switches being replaced by 28kV rated switches.
b) How many switches are being replaced as part of the load-break switch replacement program?
c) The numbers indicate that a number of “good” or “very good” overhead switches are to be replaced in the forecast period. What has been the historical annual failure rate for these switches?

2-Staff-37

Ref: Exhibit 2, pages 194-195, 212

Energy+ states that the FFA plan identified 217 single-phase pad-mounted transformers for renewal over the years 2018 through 2023. Only 8 are assessed to be in “poor” or “very poor” condition. Energy+ is planning to replace seventy-four (74) of these transformers over the same period through its underground rebuild programs and pad-mounted transformer replacement program. The FFA plan also identified seventeen (17) three-phase pad-mounted transformers for renewal over the years 2018 through 2023 and Energy+ is planning to replace twelve (12) of these over the same period through its underground rebuild programs and pad mounted transformer replacement program. All three-phase pad-mounted transformers are considered to be in “fair” or better condition.

a) Please explain why Energy+ planned to replace fewer transformers than the FFA plan identified.
b) How many pad- mounted transformers are being replaced as part of the pad-mounted transformer replacement program?
c) How many pad- mounted transformers are being replaced as part of the underground rebuild program?
d) The numbers indicate that a number of “fair” or better pad-mounted transformers are to be replaced in the forecast period. What has been the historical annual failure rate for these transformers?

2-Staff-38

Ref: Exhibit 2, pages 196, 212

Energy+ states that the FFA plan identified fourteen (14) pad-mounted switchgear for renewal over the years 2018 through 2023. Only 1 is assessed to be in “poor” or “very poor” condition. Energy+ is planning to replace twelve (12) of these switchgear over the same period through its underground rebuild programs and pad-mounted switchgear replacement program.

a) How many switchgear are being replaced as part of the pad-mounted switchgear replacement program?
b) How many are “live-front” switchgear?
c) How many switchgear are being replaced as part of the underground rebuild program?
d) The numbers indicate that a number of “fair” or better pad-mounted switchgear are to be replaced in the forecast period. What has been the historical annual failure rate for these switchgear?

2-Staff-39

Ref: Exhibit 2, page 211

Energy+ states that grounding systems are run to failure (Table 3-21).

a) Does Energy+ have an inspection and testing program to determine when grounding has failed at various locations?

2-Staff-40

Ref: Exhibit 2, page 222

Energy+ states that asset refresh for IT hardware is based on a 3 year cycle.

a) How has this cycle been determined?

2-Staff-41

Ref: Exhibit 2, page 228

Energy+ states that it has implemented formal policies and procedures designed to: (i) increase interaction with customers; (ii) obtain feedback with respect to customer satisfaction levels, complaints, stated needs, and preferences; and (iii) integrate this ongoing and augmented customer feedback into the annual business/department planning processes.

a) Please provide copies of these formal policies and procedures.

2-Staff-42

Ref: Exhibit 2, page 168, 245

Energy+ has stated its Asset Management Objectives and Planning Objectives in the DSP.

a) What is the specific linkage between the Planning Objectives and the Asset Management Objectives?

2-Staff-43

Ref: Exhibit 2, page 276

Energy+ forecasts $1.175 million in capital spending annually in the 2020 – 2023 period for underground servicing of new or upgraded industrial, commercial, multi-unit residential or institutional buildings. Energy+ states that as the exact number of projects is not known until customer requests are made, Energy+ examines historical customer attachment figures to gain insight for planning.

a) How was this forecast calculated from the historical customer attachment figures?

2-Staff-44

Ref: Exhibit 2, page 287, 293, 296

On pages 293 and 296, Energy+ indicates 1100/1022 new meters in 2019. No customer attachment numbers are shown for the 2020 – 2023 forecast period, however capital costs for meter installations are shown as increasing every year after 2019. In contrast, forecasts on page 287 indicates only 465 residential connections annually over the forecast period.

a) Please explain the difference between the meter customer attachment forecasts and the residential connection forecasts.

2-Staff-45

Ref: Exhibit 2, page 303

Energy+ states that the total estimated cost of the Brant Business Park servicing is $496,500. The cost estimate for this project has been reduced by 40% to $297,900 in the 2019 budget to reflect timing uncertainty. This represents a potential budget shortfall of approximately $200k.

a) What other works will be deferred in order to accommodate the additional $200k in capital spending should actual servicing costs be on track and per original estimate?

2-Staff-46

Ref: Exhibit 2, page 340-341

System Renewal – SR-002 is an overhead 3 phase rebuild project. 95 poles are to be replaced of which 88 are owned by Energy+.

a) Who owns the other 7 poles?
b) Are these poles owned by others in similar asset health condition as the Energy+ owned poles?
c) Please confirm that the previous pole owner(s) will now be joint use on Energy+ owned poles.

2-Staff-47

Ref: Exhibit 2, pages 379

In 2019, Energy+ has budgeted $450,000 for replacement transformer cost and transformer repair cost.

a) Please confirm that spare distribution transformers, for replacement purposes, are held in inventory and not PPE.

2-Staff-48

Ref: Exhibit 2, pages 402

Energy+ has a program for the planned replacement of line post style porcelain insulators with polymer insulators.

a) What is the kV rating of the replacement polymer insulators?

2-Staff-49

Ref: Exhibit 2, pages 766

Energy+ states that "With regards to investments that focus on replacing aging equipment in poor condition, between 58% and 64% of low-volume customers feel that Energy+ should "invest what it takes to replace the systems aging infrastructure, even if that increases my monthly electricity bill by a few dollars over the next few years."" Specifically Energy+ stated to the customers that their renewal projects focused on replacing aging equipment in poor condition.

a) As a number of projects will result in replacing equipment in "fair" or better condition over the forecast period, does Energy+ still consider the low volume customer response to be an accurate understanding of what was being undertaken by the System Renewal investments?

2-Staff-50

Ref: Exhibit 2, pages 770, 778

Energy+ states that 1,573 of 65,000 Energy+ customers (2%) participated in the customer engagement exercise.

a) Does Energy+ consider this to be a statistically relevant sampling?

Exhibit 3 – Operating Revenue

3-Staff-51

Ref: Load Forecast Model, Tab Rate Class Energy Model, Loss Factor

Energy+ uses the average loss factor (1.0282) for the 2010-2017 period to convert the modeled purchases to the billed purchases. Table 1 is reproduced using data from the Rate Class Energy Model tab in the Load Forecast Model. As shown in the table, the loss factor decreases in recent years.

Table 1. Energy+ Historical Loss Factor

Year	Loss Factor
2010	1.0359
2011	1.0361
2012	1.0312
2013	1.0202
2014	1.0300
2015	1.0155
2016	1.0272
2017	1.0294
Average (2010-2017)	1.0282
Average (2013-2017)	1.0245

In Appendix 2-R, the 5-year average loss factor is 1.0261.

a) Please discuss if Energy+ would consider using a five-year average of loss factor for load forecast purpose to reflect the decrease in loss factor in recent years.

3-Staff-52

Ref: Exhibit 3, page 28-29, Table 3-31

Table 3-31 provides a summary of total load forecast, it shows the customer counts and consumption (kWh) for GS<50 kW class as follows:

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Test
General Service < 50 kW										
Customers	5,893	5,932	5,980	6,004	6,057	6,149	6,241	6,298	6,374	6,451
% change year over year		*0.7%*	*0.8%*	*0.4%*	*0.9%*	*1.5%*	*1.5%*	*0.9%*	*1.2%*	*1.2%*
kWh	199,237,830	194,492,494	194,297,829	193,717,267	198,149,245	203,100,575	212,807,519	189,005,848	192,724,357	195,276,256
% change year over year		*-2.4%*	*-0.1%*	*-0.3%*	*2.3%*	*2.5%*	*4.8%*	*-11.2%*	*2.0%*	*1.3%*

a) Please explain why there was an 11.2% decrease of consumption in 2017 compared to 2016 considering that the customer counts increased by 0.9%.

3-Staff-53

Ref: Exhibit 3, pages 6, 15.

Energy+ included a variable named Co-generation Facility Flag in its regression to reflect the impact of new co-generation facilities added in 2016. The regression dummy variable indicated a load reduction of 7.3 GWh per month associated with the co-generation facility. This implies a reduction in load of 88.0 GWh per year.

a) Please confirm that the co-generation added in 2016 is at a single large user site, or please explain.
b) Does Energy+ have a way to directly measure the production of the co-generation added in 2016?
c) If the answer to part b) is yes, why did Energy+ choose to model the impact using a regression rather than a direct adjustment to the forecast?

3-Staff-54

Ref: Exhibit 3, page 22.

Energy+ has also adjusted the CDM adjustment to the load forecast to reflect the “new load displacement generation that will be charged a standby charge“. This adjustment reduced the CDM adjustment from 32.1 GWh to 16.9 GWh, a reduction of 15.3 GWh per year. This serves to increase the load forecast by 15.3 GWh per year.

a) Please explain why Energy+ did this adjustment.
b) Please provide a derivation of the 15.3 GWh reduction to the CDM adjustment.
c) What quantity does Energy+ expect to bill for the standby charge?

3-Staff-55

Ref: Table 3-31, Summary of Total Load Forecast

a) Please clarify whether the kWh forecast for the total system of 1,665,268,498 kWh includes the energy forecast for all WMPs (i.e. including WMPs that are classified in the GS>50 to 999 kW class and GS>1000 to 4999 kW class).

3-Staff-56

Ref: 3.4.1 Other Revenue Overview

Pursuant to the Report of the Board Wireline Pole Attachment Charges (EB 2015-0304) issued March 22, 2018, Energy+ acknowledges the change in the pole attachment charge to $43.63 effective January 1, 2019. Energy+ intends to increase the pole rental revenue included in this application as part of the application process. As the OEB Report was issued late into Energy+'s rate application process, there was insufficient time to update the various models prior to the filing date. In addition, Energy+ noted that it is subject to pole attachment charges from telecommunication companies, which are included in OM&A expenditures. Energy+ expects that the telecommunication companies may in fact increase the pole attachment charges that it charges to Energy+ as a result. Energy+ would also expect to address this as part of the application process.

a) Please update the pole rental revenue with the new pole attachment charge of $43.63.
b) Please update OM&A expenditures with respect to pole attachment charge from telecommunication companies, if required.

3-Staff-57

Ref: 3.4.4 Revenues from Affiliates, Shared Services and Corporate Cost Allocations, Appendix 2-N: Shared Services and Corporate Cost Allocation

Energy+ forecasted revenues of $241,360 from affiliate transactions and shared services for 2019. Appendix 2-N provided the breakdowns for shared services and corporate cost allocation.

a) Please explain how did Energy+ account for revenues of $241,360 related to affiliate transactions and shared services (i.e. as part of revenue offsets of $1,654,991)?
b) Please reconcile the forecasted revenues of $241,360 with Appendix 2-N (for 2019 test year).
c) Please explain the difference between the sum of cell I16:I35 and cell I41 in Appendix 2-H, Other Operating Revenue.

3-Staff-58

Ref: Exhibit 3, pages 6-10.

Energy+ identified two tested and discarded variables for Ontario Real GDP Monthly % and Employment Kitchener-Waterloo-Barrie (000's) due to a lack of statistical significance. It did not indicate whether a trend variable was attempted.

a) Did Energy+ attempt a regression with a trend variable? If so, please provide the results. If not, why not?

3-Staff-59

Ref: Exhibit 3, page 14.
Filing requirements, July 12, 2018, page 23

Energy+ states that its “weather normal values for 2019 are provided on a 20 year trend assumption for weather normalization.” However, the Load Forecast Model, on the Purchased Power Model worksheet, cells G123:H134 appear to be calculating heating degree days and cooling degree days based on a ten year average, and these values appear to be used in the derivation of the forecast for 2018 and 2019. The filing requirements state that “In addition to the proposed test year load forecast, the load forecasts based on 10-year average and 20-year trends in HDD and CDD” must be provided.

a) Please confirm that the forecast is actually based on a ten-year average definition of weather normal, or explain.
b) Please provide a load forecast based both a ten-year average and 20-year trend definition of weather normal

Exhibit 4 – Operating Costs

4-Staff-60

Ref: Exhibit 4, page 27, Incremental Monthly Billing Costs

Included in the 2019 test year OM&A is a $390,000 incremental annual costs as a result of the transition to monthly billing.

In Table 4-11, Energy+ provides the incremental OM&A expenditures with respect to monthly billing.

Table 4-11: Incremental Monthly Billing OM&A Expenditures

Description	Amount	Explanation
Incremental Customer Care/Billing Resources	140,000	Hiring of one additional Customer Care Clerk and 1 Billing Clerk
Incremental Postage and Bill Printing	225,000	Postage costs due to mailing of invoices every month
Other	25,000	Subcontractor costs, incremental Collection Notices; Processing of increased payments.
	$ 390,000	

Energy+ states customers of the former BCP were billed on a monthly basis prior to the acquisition by the former CND in 2014. As such, incremental costs associated with monthly billing for only those customers in the Energy+ CND service territory have and will be recorded in a deferral account up until December 31, 2018. For the 2019 test year, the annual costs incurred by Energy+ for monthly billing are recorded in OM&A and the incremental costs associated with the CND service territory are a specific driver of the increase in OM&A between the 2014 OEB approved proxy and the 2019 test year.

Based on Appendix 2-JA: Summary of Recoverable OM&A Expenses, OEB staff produced Table 2 as follows:

Table 2: Summary of Billing and Collecting Expenses

	Last Rebasing Year (2014 Board-Approved Proxy)	Last Rebasing Year (2014 Actuals)	2015 Actuals	2016 Actuals	2017 Forecast	2018 Bridge Year	2019 Test Year
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Billing and Collecting	$ 3,730,609	$ 3,477,666	$ 3,330,327	$ 3,548,298	$ 3,391,259	$ 3,372,867	$ 3,945,340
$Change (year over year)		*(252,943)*	*(147,339)*	*217,971*	*(157,039)*	*(18,392)*	*572,473*
%Change (year over year)		*-7%*	*-4%*	*7%*	*-4%*	*-1%*	*17%*

a) Please explain why billing and collecting expenses are forecast to be 4% lower for 2017 than 2016, and 1% lower for 2018 than 2017.
b) Please clarify when Energy+ hired one additional customer care clerk and 1 billing clerk as noted in Table 4-11.
   i. Please reconcile your response with Table 4-24 (Exhibit 4, page 60 of 540).
c) Please provide the actual incremental monthly billing OM&A expenditures in 2017.
d) Other than the $390,000 incremental monthly billing costs, please explain the rest of the increase in billing and collecting expenses that supports a 17% higher budget for 2019 test year than 2018.
e) Please explain how much postage and bill printing costs were saved as a result of a 32% increase in e-billing customers from 2015 to 2017.
f) Please specify currently how many customers were enrolled in e-billing (i.e. at the end of the latest billing cycle).
g) Please explain how Energy+ will continue to promote e-billing to customers.

4-Staff-61

Ref: Exhibit 4, page 31, Shared Services with Brantford Power Inc.

There is an increase of $195,000 operating cost in 2019 with respect to shared services with BPI.

The increase in operating costs of $195,000 is comprised of the following:

	Annual Cost
Shared Space Operating Lease Estimate	$255,000
Shared Mechanic (1/2 FTE)	40,000
Operating Costs (Exclusive Space)	35,000
	$330,000
Less: Current Operating Costs (Existing Facility)	(135,000)
Total Operating Costs	$195,000

a) Table 5 of Appendix N in the DSP shows an annual lease cost for shared space of $155,652 while the table above shows shared space operating lease estimate of $255,000. Please explain the difference.
b) Please explain how sharing facilities and services with BPI will reduce operating costs to Energy+ when the operating cost budget is increased by $195,000 in 2019.

4-Staff-62

Ref: Employee Costs

App. 2-JB shows an increase of $1,208,764 from 2014 actual to 2019 test year budget in Merit/Collective Agreement. App. 2-K shows an increase of $1,085,074 from 2014 actual to 2019 test year budget in total compensation.

a) Please explain the difference between these two.

4-Staff-63

Ref: Number of FTEs

App. 2-K and App. 2-L shows different number of FTEs for 2017.

a) Please explain the difference and update Appendix 2 accordingly.

4-Staff-64

Ref: Tab 1-a of LRAMVA workform, Energy+ (CND rate zone)

Exhibit 4, Appendix 4-6 (IndEco Report), page 309 of 540

Energy+ is requesting to dispose of a debit amount of $1,200,452.19 for its LRAMVA as part of its 2019 cost of service application.
Energy+ LRAMVA claim consists of two components:

- Energy+ (CND rate zone) of $862,195.37
- Energy+ (Brant county rate zone) of $338,256.82

Energy+ included a third party LRAMVA report completed by IndEco. The IndEco Report indicated that the LRAMVA disposition included unverified energy savings for 2016 adjustments and 2017 savings provided by the IESO as of January 2018. Tables 1 and 2 of the IndEco Report quantified the amount of unverified savings in the LRAMVA. Energy+ further noted that the LRAMVA values will be updated once the final verified results are available.

At Note 10 of Table A-1 (Tab 1-a of the LRAMVA work form), the final verified results for 2016 and 2017 were to be expected in July 2018.

a) Please confirm whether the Final Results Report for each of Energy+'s CND and Brant county rate zones can be provided by the IESO for 2016 and 2017.
    i. If so, please update the LRAMVA workform with the final verified 2017 results provided by the IESO.

4-Staff-65

Ref: Tab 2 of LRAMVA workform, Energy+ (CND rate zone)

EB-2013-0116, CND's 2014 Settlement Agreement, page 19 of 30

In CND's 2014 Settlement Agreement, an LRAMVA threshold of 40,780,000 kWh was approved. As for the LRAMVA threshold used for calculation of lost revenues, it appears that 1,254,827 kWh of CDM savings was removed. As a result, an LRAMVA threshold of 39,520,173 kWh was used for comparison against actual savings.

a) Please clarify whether any Direct Market Participants in CND's service territory participated in the IESO's provincially funded CDM programs during 2014 to 2017.
b) Please explain how the lost revenues from Direct Market Participant customers have been accounted for in the load forecast from the last rebasing application and in the current LRAMVA claim, if any.

4-Staff-66

Ref: Tab 3-a of LRAMVA workform, Energy+ (CND and Brant county rate zones)

Exhibit 4, Appendix 4-6 (IndEco Report), page 308 of 540

The IndEco Report notes that the allocation of actual savings by rate class and service territory was based on project-specific information, where available.
In Tab 3-a of the LRAMVA work form, a table showing the persisting rates by program level was provided. It was also confirmed that the rate allocations for 2015 adjustments and 2016 savings took into account the relative split of program results by rate zone.

a) Please explain how the allocation of verified savings for the business retrofit program was split between the two rate zones.
b) Please elaborate on the approach used to determine the rate class breakdown of savings.
c) Please discuss how the rate class allocations were determined based on the table provided in Tab 3-a.

4-Staff-67

Ref: Tab 5 of LRAMVA workform, Energy+ (CND and Brant county rate zones)

In Tables 5-b and 5-c, it appears that more savings could be claimed for three CDM programs, as the percentage of these program savings divided between the two rate zones exceeded 100%.
Please confirm the following rate allocations:

a) At program 26 of Table 5-b (i.e., 2016 Save on Energy Retrofit Program), accuracy of the allocation of 79% of savings to the CND rate zone when 26% of savings were allocated to the Brant county rate zone.
b) At program 28 of Table 5-b (i.e., 2016 Save on Energy High Performance New Construction Program), accuracy of the allocation of 72% of savings to the CND rate zone when 38% of savings were allocated to the Brant county rate zone.
c) At program 24 of Table 5-c (i.e., 2017 Save on Energy Home Assistance Program), accuracy of the allocation of 100% of savings to the CND rate zone when 100% of savings were allocated to the Brant county rate zone.

4-Staff-68

Ref: Tab 9 of LRAMVA workform, Energy+ (CND rate zone)

In Tab 9, Energy+ provided a table that showed the persisting savings from a CHP project into 2016 and 2017. Energy+ noted that persistent load reductions are calculated from monthly maximum load in the facility minus the amount billed.

a) Please confirm whether the CHP project was undertaken as part of an IESO CDM Program (specifically, the Process and Systems Upgrades Initiatives – Project Incentive Initiative).
   i. If yes, please confirm the years in which the CHP program savings were verified by the IESO.
   ii. If no, please confirm the appropriateness of claiming lost revenues from the CHP project.
b) Please provide the rationale for claiming demand savings from the CHP program separately from the IESO CDM Program.
c) Please reconcile the demand savings from the CHP project with the verified energy savings for this project (i.e., 58,955,828 kwh as shown in Tab 5, Table 5-a, program 11)? Please provide supporting analysis to show the conversion from energy to demand savings for this project.
d) Please confirm that the energy savings from the CHP project have accordingly been reduced from the IESO CDM program.
e) Please confirm the specific reference source of the NTG value (e.g., NTG ratio of 1.00132) in the IESO Results Report.

4-Staff-69

Ref: Tab 8 of LRAMVA workform, Energy+ (Brant county rate zone)

Energy+ (Brant county rate zone) has included streetlighting savings as part of its LRAMVA claim.

a) For Brant's claim of streetlighting savings in 2016, please confirm:
   i. The period in which the streetlighting demand savings are claimed for Energy+ (Brant county rate zone). Is it over a 2-month period from November to December 2016?
   ii. Whether the monthly breakdown of streetlighting savings is consistent with the Board-approved load profile for streetlighting customers from Brant county's 2011 cost of service application.
   iii. The specific reference source of the NTG value (i.e., NTG ratio of 0.79) in the IESO Results Report.

b) For Energy+ (Brant county rate zone)'s claim of persisting savings from 2016 into 2017, please discuss the appropriateness of the methodology used to determine 1,903 kW in persisting streetlighting savings in 2017.
c) Please confirm whether the persistence rate of streetlighting projects from 2016 into 2017 is consistent with the rate of persistence used by the IESO for similar projects.

4-Staff-70

Ref: Tab 6 of LRAMVA workform, Energy+ (CND and Brant county rate zones)

Please update Table 6 with the Board-approved prescribed interest rates for Q3 2018 and Q4 2018.

4-Staff-71

a) If Energy+ made any changes to the LRAMVA work form as a result of its responses to interrogatories, please file an updated LRAMVA work form.
b) Please confirm any changes to the LRAMVA workforms in "Table A-2. Updates to LRAMVA Disposition (Tab 2)".
c) Please confirm the updated LRAMVA balance and re-file an updated Table 4-57 from Appendix 4 (of Exhibit 4) in response to this interrogatory.
d) Please confirm the LRAMVA rate riders by customer class for Energy+'s rate zones.
e) Please submit the following:
    i. Final Results Report for verified 2016 savings
    ii. Final Results Report for verified 2017 savings (which is inclusive of persistence and adjustment amounts for 2016 programs)

4-Staff-72

Reference: Exhibit 4, Section 4.9.3.1

The applicant has indicated that upon amalgamation of January 1, 2016, the accounting policies for depreciation and capitalization for Energy+ were harmonized to be consistent with former CND.

a) Prior to the amalgamation date, the former BCP's useful livers were different in certain classes of assets. Please provide a summary of the change in the useful lives of BCP's that were made in order to align them with the former CND.

b) With respect to cost capitalization, please provide a summary of the changes to the former BCP's capitalization policy that were made upon amalgamation in order to align it with the former CND's policy.
c) Given that the approved rates during the deferred rebasing period were set under BCP's previous capitalization and depreciation policies, what is the revenue requirement ramification of the above policy changes? Please quantify the impact on the approved revenue requirement for 2016, 2017, and 2018 respectively.
d) Given that the above accounting policy changes directly impact BCP's approved revenue requirement during the deferred rebasing period, please explain why the applicant did not notify the OEB at the time these accounting policy changes were made so that the OEB could consider revenue requirement implications of this change?

4-Staff-73

Reference: Exhibit 4, Section 4.4.2.3.3

a) Please confirm that the accrual method is being used as the basis for recovering both the pension and other post-employment benefit costs.
b) For the 2019 test year, the applicant has indicated that it has assumed OMERS contribution rates of 9% on earning up to CPP earning limits and 14.6% on earnings over CPP earning limit. Please confirm that there has not been any change to these rates since the filing of the application.
c) Please provide the calculation performed to arrive at the estimated test period employer pension contributions to the OMERS plan.
d) With respect to other post-employment benefits, the applicant is seeking to recover $182,354 for the 2019 test period. However the applicant has submitted a valuation that was performed to determine the 2016 expense. What is underpinning the amount being sought for the 2019 test period?
    i. If it is not being underpinned by an actuarial valuation, please provide the back-up used to estimate the test period amount.
    ii. Why has the applicant not used an actuarial valuation to estimate these amounts?
e) In Table 4-33, why is the actuarial expense for the test period and the premiums paid for the test period the same number?
    i. Should not the actuarial expense equal the post-retirement benefits earned by employees in the year as determined on an accrual accounting basis through an actuarial valuation, whereas the premiums paid represent the actual cash costs paid by the utility for the year in respect to the provision of post-retirement benefits?

Please explain what each of these lines represent and why it is appropriate that these numbers are the same.

f) For the pension and other post-employment benefit cost amounts being sought for recovery in the test period, please provide a table that breaks-out the capital and OM&A components of each of these costs.

4-Staff-74

Reference: Exhibit 4, Section 4.10 and PILS Workform

a) The applicant has used a dated version of the OEB PILs Model. Please complete and submit the most up to date version of this Model which is now available on the OEB website. Please ensure that 2017 actual numbers are used when populating the updated PILs Workform (for historical year).
b) Please provide a copy of the 2017 corporate income tax return
c) In Table 4-52, the applicant presents a computation of taxable income for the test period. It has indicated that the change in the financial statement reserves used in this computation represents the post-employment benefit liability as presented in Table 4-33. However the numbers used in the computation do not correspond with Table 4-33, please explain why.

Exhibit 6 – Revenue Requirement

6-Staff-75

Reference: Exhibit 6, Revenue Requirement Workform

a) As part of the acquisition of the former BCP, the purchase price paid by the applicant included a premium of approximately $16.3 million. Please confirm that this premium has been excluded from the calculation of the test period rate base as well as from other areas of the test period revenue requirement being sought in this application.

Exhibit 7 – Cost Allocation

7-Staff-76

Ref: 7.1.3.5 Embedded Distributor Classes

Energy+ is proposing two additional Embedded Distributor Service Classifications in the BCP service area. There will be one class for Brantford and another class for Hydro One. Energy+ has provided the cost allocation and rate design information to each of its embedded distributors.

Energy+ received confirmation from Hydro One that Energy+'s proposal is reasonable, with the exception of one item that was identified. For one of the accounts in the Brant Service territory, Energy+ inadvertently included a value of $33,555 with respect to Meter Capital in the Cost Allocation Model. As the meter for this account is owned by Hydro One, the value should not have been included. Energy+ agrees with the exception noted by Hydro One.

a) Please confirm whether BPI and Hydro One are currently classified under the GS 50 to 4,999 kW service classification.
b) Please update the Cost Allocation Model to exclude the value of $33,555 with respect to Meter Capital for Hydro One in the Brant service territory.

7-Staff-77

Ref: 7.1.3.8 Standby Rates

Energy+ proposes to implement a Standby Charge for all customers in the GS>50 kW and larger rate classes that have load displacement generation (LDG). The options considered were no standby/capacity charge, gross load billing, name plate capacity and contracted capacity. Energy+ proposes to use the contracted capacity method.

a) Please provide a detailed description of the Name Plate Capacity method and Gross Load Billing method.
   ii. Please explain how standby rates would be determined using these methods.
   iii. Please explain how standby customers would be charged using these methods.

b) Please provide detailed rationale supporting Energy+'s proposal to use the contracted capacity method.
c) Please advise whether it is Energy+'s proposal to apply standby rates to all customers with installed LDG (in the noted classes). Alternatively, please advise whether the generation capacity will need to be above a certain threshold to attract standby charges. If a threshold will be applied, please provide the threshold.
d) Please advise whether Energy+ considered taking into account potential system benefits attributable to customers with LDG when determining standby rates. If so, how. If not, why not.
e) Please advise whether Energy+ plans to review the annual peak loads with load displacement generation customers each year and adjust the contracted capacity reserve amount during the IRM period as needed.
f) Please advise whether Energy+ has considered using an average of annual peak load (for all years that LDG has been installed) as the contracted capacity amount. For example, averaging the 2016 and 2017 annual peak load to use as the 2019 contracted capacity reserve amount.
g) Please explain how the proposed inclusion of a contracted capacity reserve amount impacts the allocation and disposition of balances recorded in the various deferral and variance accounts sought for clearance as part of the current proceeding.
h) Please advise whether the definition of a standby/capacity charge is documented in Energy+'s current Conditions of Service? If not, what changes is Energy+ proposing to its Conditions of Service to document the relevant conditions for customers who may be subject to the proposed Standby Rate?

7-Staff-78

Ref: Energy+ Responses to TMMC Questions, dated July 16, 2018

Energy+ provided a number of responses to TMMC questions (dated July 16, 2018).

Specifically, Energy+ provided an analysis of potential rates and cost implications for TMMC using different methodologies to determine standby rates in response to Question 9.

a) Please advise whether it is Energy+'s proposal to use the 2016 peak load amount or the 2017 peak load amount as the contracted capacity for TMMC.
b) Please explain how miscellaneous revenue were allocated in the Q9 scenario analysis.
c) Please discuss which method (i.e. gross load billing, name plate capacity, and contracted capacity) leads to the lowest allocated costs and which method leads to the highest. Please discuss whether it will be the same case for all customers with LDG or the costs are related to each customer's specific load profile?

7-Staff-79

Ref: Exhibit 7, page 6
Cost Allocation Model, Sheet I5.2 – Weighting Factors

Energy+ states that "There were no assets associates with Services recorded in account 1855 for the CND service area". Instead, the account reflects BCP alone for which there are $1.3 million net book value of assets. It has continued to explain that "Since the value in relatively small compared to the asset values in other asset classes, Energy+ has used a weighting factor of 1.0 for the Residential, General Service < 50 kW, General Service > 50 to 999 kW and General Service > 1000 to 4999 kW classes."

a) Which account has been used to track the asset value for service drops in the CND service territory?
b) Please provide an estimate of the value of service drops in the CND service territory.
c) Prior to the integration confirm which rate classes were responsible for providing their own service drop in each of the former utilities of CND and BCP.
d) Currently, which rate classes are responsible for providing their own service drop?
e) Please estimate the proportion of customers in each rate class which have supplied their own service drop.
f) Please estimate the cost to Energy+ of providing a service drop to the average customer in each rate class.

7-Staff-80

Ref: Exhibit 7, page 6
Cost Allocation Model, Sheet I5.2 – Weighting Factors

Energy+ used the billing and collecting weighting factors from the former CND's 2014 Cost of Service application as the basis for the weighting factors in the current application.

a) Has Energy+ integrated the billing and collecting system and processes of CND and BCP into a single set of systems and processes?
b) Please explain which components were retained from CND and which were retained from BCP.

7-Staff-81

Ref: Exhibit 7, page 7
Cost Allocation Model, Sheet I7.1 – Meter Capital
Cost Allocation Model, Sheet I7.2 – Meter Reading

Energy+ has included 3,371 of 6,450 total meters the GS < 50 kW rate class as "Demand without IT (usually three-phase)". The same type was used for 90 of the 801 meters in the GS > 50 to 999 kW rate class. However, Energy+ states that it "has converted all of its residential and GS<50 kW customers to smart meters." And that "meters for all other classes are read using an interval meter." In addition, there are 458 "Demand with IT" meters used by the GS > 50 to 999 kW rate class.

a) Please explain how the "Demand without IT (usually three-phase)" meters are read as smart meters in the GS < 50 rate class, and are read as interval meters in the GS > 50 to 999 kW rate class.
b) Please explain the distinction between the "Demand with IT" and Demand with IT and Interval Capability – Secondary" meter types.
c) If the distinction in part b) is interval capability, please explain how the "Demand with IT" meters are read.

7-Staff-82

Ref: Cost Allocation Model, Sheet I6.2 – Sheet I6.1 Revenue / Sheet I8 Demand Data

On sheet I6.2, 729 GS > 50 to 999 kW customers are included as using line transformers owned by Energy+, while 786 customers in that rate class are included as being connected to the Energy+ secondary distribution system. Similarly in the GS > 1000 to 4,999 kW rate class, 6 customers rely on Energy+ for transformation, while 18 customers are connected to the Energy+ secondary system.

a) Please explain or correct the apparent inconsistency of some customers owning their own transformers, but then being connected to the common secondary system.

7-Staff-83

Ref: Exhibit 7, page 8-9
Cost Allocation Model, Sheet I4 – BO Assets
Cost Allocation Model, Sheet I9 – Direct Allocation
Proposed Embedded Dist Charge Calculation

In the Proposed Embedded Dist Charge Calculation workbook, the sheet Proposed LV Cost WNH indicates $39,916 of amortization expense associated with serving this distributor. This amount reconciles with the direct allocation on sheet I9 Direct Allocation in the cost allocation model. For the same embedded distributor, a total of $20,414 of OM&A has been directly allocated in the Cost Allocation model. However, $22,864 of OM&A is calculated in the Proposed Embedded Dist Charge Calculation workbook. The Proposed Embedded Dist Charge Calculation workbook also includes return on assets of $32,474 and PILs of $6,867.

Energy+ has $7,494,680 net book value associated with transformer stations, yet none of the embedded distributors have any transformer station costs assigned.

a) For all embedded distributors, please reconcile the OM&A, Return on Assets, and PILs between the Cost Allocation Model, and the Proposed Embedded Dist Charge Calculation workbook.
b) Please confirm that none of the embedded distributors rely on the services of an Energy+ transformer station.

7-Staff-84

Ref: Exhibit 7, page 10-14
Cost Allocation Model, Sheet I8

Energy+ has a Large Use customer that has load displacement generation. However, it is not proposing a standby rate class. In 2016, Energy+ provided the standby customer a peak load of 28.8 MW. Energy+ has one other Large Use customer. The total 1NCP for the Large Use rate class, including the other customer in the class is 26.6 MW.

a) Please explain how the demand allocators on sheet I8 Demand Data reflect the standby capacity.
b) What is the capacity of the load displacement generator Energy+ is providing standby service for?
c) What would the 1NCP, 4NCP, 12NCP, 1CP, 4CP, and 12CP values for the large use class be, counting only the demand related to the normal operation of its Large Use customers? I.e. demand that is not related to Energy+ delivering power to replace the load displacement generator.

7-Staff-85

Ref: Exhibit 7, page 3
Cost Allocation Model, Sheet I8
Load profile model 2006 Hydro One Data for 2019

Energy+ has based its load profiles on the 2004 weather normalized volumes; scaled to the 2019 forecast. The load profile model generates NCP and CP values in the sheet Hourly load shapes by class, rows 8802 to 8821. In some classes, for example Residential and GS < 50, the NCP and CP values reconcile to I8 Demand Data exactly. In other classes there are differences. For example, GS > 50 to 999, the load profile model reflects 4CP of 293,095 kW, and 4NCP of 328,083 kW while the corresponding values in the Cost Allocation model are 299,118 kW, and 334,106 kW. Differences are found for all CP and NCP values in the GS > 50 to 999 kW, GS > 1,000 to 4,999 kW and Large Use rate classes.

a) Please reconcile the differences between the load profile model and the cost allocation model
b) If Energy+ believes the values in the Cost Allocation model to be correct, please explain how, in the Large Use rate class, the 12NCP (reflecting the sum of the 12 monthly peaks) is more than 12 times the

1NCP (reflecting the highest peak of the year), and how the 4NCP (reflecting the sum of the four highest peaking monthly peaks) is more than four times the 1NCP.

7-Staff-86

Ref: Exhibit 7, page 18
RRWF Sheet 11. Cost Allocation.

Energy+ proposes to move the revenue to cost ratio for all embedded distributors to 100%.

a) Please explain why a revenue to cost ratio of 100% was selected instead of moving embedded distributors to the boundary of the range.
b) Energy+ indicates a policy range of 85%-115% in the RRWF, and a policy range of 80%-120% for embedded distributors in Table 7-7 of the written evidence.

Exhibit 8 – Rate Design

8-Staff-87

Ref: 8.2.1 Retail Transmission Rates, Harmonized RTSR rates

Energy+ is seeking to harmonize rates, which would include the RTSR rates. In order to facilitate this harmonization, Energy+ undertook the following steps:

- Preparation of the RTSR_Workform for each of the CND and Brant service territories, utilizing the 2017 IRM Approved RTSR Rates by rate zone.
- Energy+ then applied these rates to the 2019 load forecast by rate class and by service territory to determine the total dollars to be collected by rate class. Energy+ divided the calculated total dollars by the total 2019 billing determinants for each rate class.

a) Please update the RTSR_Workform for each of the CND and Brant service territories utilizing the 2018 IRM approved RTSR rates.
b) Please confirm if 2017 RRR data was used in RTSR_Workform for each of the CND and Brant service territories. If not, please update the workform for each territory accordingly.

c) Please explain how Energy+ determine a loss factor of 1.0287 for CND service territory and a loss factor of 1.2870 for Brant service territory in the RTSR_Workform.
d) Please specify what loss factors Energy+ applied to the 2019 load forecast to determine the loss adjusted billing determinants.
e) Please update 2019 RTSR Harmonized Excel file to ensure that the same billing determinants are used for residential class for network rates and connection rates calculation.

8-Staff-88

Ref: 8.2.1 Retail Transmission Rates, Gross Load Billing Method for a Large User

Energy+ has a Large User. Energy+ is charged on a gross load billing basis from the IESO for wholesale transmission services since this customer has load displacement generation. As a result, Energy+ proposes to charge the RTSRs to this customer on a gross load basis.

Energy+ is also requesting the gross load billing methodology for RTSRs for any customer in the future that implements load displacement generation to align to the methodology used by the IESO.

The customer has advised Energy+ that it is not in agreement with Energy+'s proposal with respect to the use of gross load billing for wholesale transmission services.

a) Please clarify whether the proposed gross load billing methodology applies only to Retail Transmission Rate – Line and Transformation Connection Service Rate.

8-Staff-89

Ref: Rate Harmonization

In the MAAD's application, the former CND estimated that approximately 98.6% of the combined CND/BCP customer base will realize lower distribution rates in 2019 than would otherwise be expected in the absence of the transaction.[1] The

[1] Decision and Order, EB-2014-0217/EB-2014-0223, October 30, 2014,

former CND provided an indicative estimate and showed that in the BCP service area, with the exception of the GS>50 kW customer class, 98.8% of BCP's existing customers are expected to realize lower distribution rates in 2019 than would otherwise be expected. For CND, it was stated that 100% of existing customers are expected to realize lower distribution rates in 2019.

Table 3. Estimated distribution rate impacts for CND and BCP customers[2]

Rate Class	Change in CND Base Distribution Rates (%)	Change in CND Total Bill (%)	Change in BCP Base Distribution Rates (%)	Change in BCP Total Bill (%)
Residential	-1.7%	-0.4%	-5.2%	-1.4%
General Service less than 50 kW	-6.7%	-1.2%	-12.7%	-2.5%
General Service 50-999 kW	-2.3%	-0.4%	54.8%	6.2%
General Service 1000-4999 kW	0.0%	0.0%	Not Applicable	Not Applicable
Large User	-7.2%	-0.4%	Not Applicable	Not Applicable

In this application, Energy+ stated that the amalgamation resulted in approximately $1.2M savings in operating, maintenance, and administration expenditures by the end of 2017 and the distribution rates in each of the respective service territories would have been higher in the absence of these cost savings.

a) Please provide an analysis similar to Table 3 to compare the 2019 distribution rates and total bills for CND customers assuming there has been no amalgamation with the rates/total bills proposed in this application. Please provide the analysis both in dollars and in percentages.
b) If any deviations are identified from the 2014 analysis, please explain why.

8-Staff-90

Ref: Section 8.2.6 Low Voltage Service Rates

Energy+ has estimated its LV charges to be $806,325 by using the 2019 load forecast quantities multiplied by the 2017 LV Rates.

a) Please provide actual LV costs for the last three historical years (2015-2017) and explain why 2017 LV rates were used for 2019 forecast.

[2] EB-2014-0217/EB-2014-0223, Exhibit A, Tab 2, Schedule 1, page 19 of 27

8-Staff-91

Ref: Section 8.5 Bill Impacts

The total bill impacts for Unmetered Scattered Load and Sentinel Lighting in the BCP service area are, 19.7% and 27.6% respectively, which are greater than the 10% threshold.

a) Please explain why Energy+ did not propose any mitigation plans for these rate classes.

8-Staff-92

Ref: 8.2.1 – Retail Transmission Service Rates – Gross Load Billing

Energy+ noted that it is charged on a gross load billing basis by the IESO for transmission services related to its LDG customer. As a result, Energy+ proposes to charge the RTSR to this customer (and to any future LDG customer that enters the system) on a gross load basis.

a) Please confirm that during the previous IRM term the LDG customer was not being charged on a gross load basis. If so, please confirm that the difference in the way that Energy+ was billed and the way that Energy+ was billing its LDG customer caused debit variances in the RTSR accounts for which clearance is sought in the current proceeding. If applicable, please quantify those variances.
b) Please explain how the amounts sought for clearance in the RTSR-related deferral accounts are proposed to be allocated.

8-Staff-93

Ref: Exhibit 8, pages 6-7
Cost Allocation Model, O2 Fixed Charge|Floor|Ceiling
Revenue Requirement Work Form, Tab 13. Rate Design

The proposed fixed charge for the GS > 1000 to 4,999 kW class and Large Use class are proposed to increase to $904.08, and $9,388.05 from $864.41 and $8.976.07 respectively. Both of these fixed charges are already above the ceiling value related to the Minimum System with PLCC Adjustment.

a) Please calculate the variable charges that would result from the scenario where the fixed charges for the GS > 1,000 to 4,999 kW class and Large Use class were held at the existing rates.

8-Staff-94

Ref: Exhibit 8, page 24
Appendix 2-R

In Chapter 2 Appendix 2-R, row A(1) is left blank.

a) Please confirm that row A(2) is populated with the lower of the two values from provided by the IESO's MV-WEB. If that cannot be confirmed, please explain the source of the data.

8-Staff-95

Ref: EnergyPlus_2019 Bill Impact spreadsheets
EnergyPlus_2019_Tariff_Schedule_Model-CND
EnergyPlus_2019_Tariff_Schedule_Model-BCP

a) Please explain why 5% tax rebate (i.e. instead of 8%) was used in EnergyPlus_2019 Bill Impact spreadsheets.
b) Please update EnergyPlus_2019_Tariff_Schedule_Model-CND and EnergyPlus_2019_Tariff_Schedule_Model-BCP and ensure that:
    i. Bill impacts for all rate classes are summarized in tab 5 for each service territory.
    ii. Group 2 account riders are included in sub-total A in the bill impacts calculation.

Exhibit 9 – Deferral and Variance Accounts

9-Staff-96

Ref: DVA Continuity Schedule

The applicant is seeking OEB approval to harmonize its rates for the CND and Brant County service territories as part this application. As part of this harmonization, the applicant also seeks to dispose of its December 31, 2017 deferral and variance account balances on a harmonized basis. Therefore a consolidated DVA continuity schedule was submitted by the applicant in support of its requested disposition of the December 31, 2017 DVA balances.

a) Please explain why the applicant feels that it is appropriate to calculate a single rate rider to be charged to customers across both rate territories, when the underlying DVA accounting balances were in fact accumulated on an individual territory basis[3]?

b) Please prepare and submit a DVA continuity schedule for each service territory. Please ensure that the 2019 OEB DVA continuity schedule is used (available on the OEB website).
c) Please amend the support and analysis provided in the application to correspond with the updated DVA continuity schedules by service territory (as needed).
d) Please provide bill impacts for all rate classes for each service territory.
e) Please reconcile tab 4. Billing Determinants with RRWF Workform Tab 10. Load Forecast.

9-Staff-97

Ref: Section 9.5, GA Analysis Workform, and DVA Continuity Schedule

a) Please prepare a separate GA Analysis Workform for each service territory. Please ensure that the latest version of the GA Analysis Workform is used. It is now a standalone workform outside of the DVA continuity schedule. It is available on the OEB website (under the IRM Models in the 2019 Electricity Rates section).
b) Please also refer to the GA Analysis Workform Instructions that must be read in conjunction with completing the GA Analysis Workform in Question 1 above. In particular, Appendix A of these instructions contain a set of questions related to accounts 1588 and 1589 that the applicant must prepare and submit responses for in support of their GA Analysis Workform. Please ensure that Appendix A is completed for each service territory.
c) The applicant had recorded principal adjustments in its DVA continuity schedule during its 2018 rate proceeding which were approved for disposition by the OEB. However the consolidated GA Analysis Workform and DVA continuity schedule that was submitted as part of this current application did not include a reversal of these previously approved principal adjustments.

[3] For example, the applicant has indicated in Exhibit 9 that the balance in Account 1576 relates entirely to Brant County. Therefore, how is it reasonable to allocate the balance across the ratepayers of both service territories when the CND ratepayers had nothing to do with the accumulation of that balance?

   i. Please ensure that these reversals are considered in the updated DVA continuity schedules that the applicant will be submitting as part of their responses to these interrogatories.
   ii. If the applicant believes that these principal adjustments should not be reversed in the GA Analysis/DVA continuity schedule, then please explain why this would be appropriate.

d) The applicant has indicated that a true-up adjustment of ($818,770) is required (on a consolidated basis) in account 1589 as a result of an under accrual of unbilled revenue at the end of 2017.
   i. Please explain how this under-accrual was quantified and provide the calculations to support this balance.
   ii. Please explain why this adjustment was not considered as a principal adjustment to the DVA continuity schedule that the applicant submitted as part of this application.

e) With respect to the applicant’s balance in account 1588, the total amount being sought for disposition is $1,219,725. In light of the fact that the variance between RPP revenue and the cost of energy attributable to RPP customers is settled with the IESO on a monthly basis, and subsequently trued-up in later months as actual data becomes available, the remaining amounts at the end of a particular year should be relatively small (primarily comprised of the difference between amounts billed at the approved loss factor compared to the actual system losses for the year).

   Please confirm that this is the case for the balance in Account 1588 that is being sought for disposition in this application. If not, please provide a detailed explanation for amounts included in the account balance.

9-Staff-98

Ref: Exhibit 9, Section 9.2

The applicant is seeking to recover the balance in Account 1575 as at December 31, 2017 of $1,908,269 (total for both service territories). The applicant has indicated that the amounts recorded in this account relate to losses on de-recognition of assets requiring replacement before the end of their useful lives and therefore had been scrapped before they were fully amortized. These losses are typically caused by unexpected equipment failure or damage, or changes in technology.

a) Please explain the difference between the two accounting standard frameworks that resulted in this IFRS transition adjustment. In providing the explanation, please reference the underlying accounting standard followed under each of the accounting standard frameworks and the particular sections within each of these standards that gives rise to this difference.
b) Under the previous Canadian GAAP, if an asset was scrapped for the reasons identified in this application (and noted in the preamble above), wouldn’t the annual depreciation of that asset cease because it was no longer considered to be in service - irrespective of whether the asset was actually written off in the books?
c) If the answer to the above yes, then please explain how this was factored into the applicant’s calculation of the amounts included within Account 1575. Specifically, as this is the first rebasing since the transition to IFRS, wouldn’t the base rates approved by the OEB in the last rebasing application still include a charge for depreciation and a related return on the impacted assets?
d) Please provide a table that compares the “loss on disposal of property plant and equipment” as per the applicant’s 2015-2017 audited financial statements (Statement of Comprehensive Income) with the amounts presented in table 9-7 of the application.
    i. In some cases the amounts tie directly to the audited statements and in others cases they do not, please provide explanations for the differences.
    ii. It appears that in all cases the annual amount being sought in this DVA account is at least equal to the total “loss on disposal of property, plant and equipment” recognized in the audited Statement of Comprehensive Income. Please confirm that in all cases the expense recognized in the audited Statement of Comprehensive income specifically relates to the accounting difference as a result of the transition to IFRS.
e) The applicant has also included a return on rate base on the balance in Account 1575. Please explain why this would be appropriate when the impacted assets would still be included in the applicant’s rate base approved in its last cost of service application. Would this not double count the return that the applicant gets on these assets?

f) Please provide the 2018 actual losses to date and then prorate this amount to the end of 2018. Compare this to the estimate for the bridge year that is included in table 9-7.

9-Staff-99

Ref: Exhibit 9, Section 9.2

The applicant is seeking the disposition of the balance in Account 1576 as at December 31, 2017 of ($2,456,018).

a) Please explain what the "Amortization Adjustment /Disposals" line of Table 9-6 is presenting and why it is appropriate to include in the overall calculation.
b) Please provide the WACC that was approved in the last rebasing application for Brant County. Would it be more appropriate to use that rate in the calculation of the return component since it represents the actual return that the applicant has been receiving on these assets based on the current approved rates.
c) Please confirm that the asset continuity schedules provided for years 2013-2015 agree to the audited financial statements for that period.
d) Why weren't detailed continuity schedules provided for years 2016-2018 in support of the calculation of the balances in account 1576 for those years?
    i. Without the use of actual continuity schedules to track the assets balances, please explain how the applicant quantified the balances included in the account from 2016-2018?

9-Staff-100

Ref: Exhibit 9 and DVA continuity Schedule

The applicant is requesting the disposition of residual balances for various Account 1595 vintage years.

a) For each vintage year being sought for disposition, please confirm that this is the first time that the residual balance of the 1595 vintage year is being brought forward for disposition. As noted in Appendix A of the Chapter 2 Filing Requirements, applicants are expected to request disposition of residual balances in Account 1595 for each vintage year only once.
b) As outlined in Appendix A of the Chapter 2 Filing Requirements, starting for the 2019 rate applications, distributors who meet the requirement for

disposition of residual balances of Account 1595 must complete the 1595 Analysis Workform. This Workform is available on the OEB's website, please complete and file this Workform accordingly. Please note that this Model should be completed for each rate zone.

9-Staff-101

Ref: Exhibit 9, Section 9.3.3

The applicant is seeking the disposition of its balance in Account 1508, sub-account Monthly Billing of $511,449.

a) Please provide the detailed calculation associated with the postage and envelope and stationary costs that have been included in this account. Please include an explanation as to how the applicant has tracked the number of incremental customer bills and other notifications that the applicant incurred as a result of its implementation of the monthly billing process.

9-Staff-102

Ref: Exhibit 9, Section 9.3.3

The applicant is seeking the disposition of Account 1555 which includes the net book value of stranded meters at December 31, 2018 related to its Brant County service territory.

a) Please confirm that the net book value of these stranded meters have been removed from the calculation of the test period rate base.

9-Staff-103

Ref: Exhibit 9, Section 9.3.4

The applicant is requesting a new deferral account called the Gain on Sale of Property to capture the expected gain on the sale of their building at 65 Dundas Street East in 2018. This facility was acquired as part of the acquisition of Brant County.

a) Please prepare and submit a draft accounting order that provides the proposed USoA account number, explains the nature and the mechanics of the account (including whether carrying charges should be applied to the account), and provides the expected journal entries to the account.

b) Has this transaction actually occurred already? If so, please provide the date of this transaction.
c) The applicant provides a calculation of the gain in Table 9-19A. It is not clear if this is the actual gain calculation or an estimate of what the gain is expected to be. Please explain.
d) If the calculation provided in Table 9-19A is the expected gain, and the transaction has since occurred, please update the calculation with actual numbers.
e) In Table 9-19A, please explain the following items of the calculation of the gain on sale"
    i. What does the "Fair Value Increase Paid by Former CND on Acquisition" represent and why is it appropriate to reduce the overall proceeds from the sale of the property by this amount?
    ii. Please explain how the "Estimate of Total Tax Cost on Sale" was calculated?
    iii. Has the actual tax impact since been calculated? If so, how does it compare to the estimate?
f) Confirm whether or not the applicant is seeking disposition of the account balance as part of this rate application.
g) If the account is approved, the applicant must include it as part of the DVA continuity schedule for this proceeding (currently this balance is not included).
h) Is the applicant still recovering the depreciation and return on rate base associated with the 65 Dundas St building in its approved 2018 rates?
    i. If yes, please quantify the revenue requirement ramification for the period from the date of disposition up to the end of 2018.

9-Staff-104

Ref: Exhibit 9, Table 9-20.

The applicant is proposing to continue Account 1508, sub-account Monthly Billing and sub-account cost assessment. The applicant is seeking the disposition of both of these account as part of this current application and the rates approved as part of this application will no longer require the need to track amounts in these accounts beyond 2018.

a) Is the applicant able to estimate the remaining amounts to be included in these accounts for 2018?
b) If such estimates can be reasonably made, would the applicant consider including these estimates in the balances being sought for disposition in these accounts as part of their current application?
c) If so, there would be no need to then continue these accounts beyond this application. The applicant would then need to propose to discontinue these accounts in this application.