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January 21, 2019

VIA E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board

Dear Ms. Walli:

Re: ENERGY + INC. 2019 RATES EB-2018-0028
VECC Technical Conference pre-filed Questions

In accordance with Procedural Order No. 7 VECC filed its Technical Conference questions for the above proceeding on January 16, 2019. On January 17, 2019 Energy+ contacted VECC seeking clarification regarding the USOA references used in a number of the questions and VECC confirmed that revisions were required to questions 70, 71, 72 and 75. Attached is a revised version of VECC's Technical Conference questions to Energy+ with the corrected references.

Yours truly,

Bill Harper

Consultant for VECC

Ms. Sarah Hughes, CFO Energy+ shughes@energyplus.ca

REQUESTOR NAME	**VECC**
TO:	**Energy+ Inc. (“E+”)**
DATE:	**January 21, 2019**
CASE NO:	**EB-2018-0028**
APPLICATION NAME	**2019 Rates**

NB – question numbering resumes from last VECC IR 60

Issue: 1.1 Capital

VECC-TCQ - 61
Reference: Update Evidence December 13, 2018

a) Given the delay in the Southwork project from 2020 to 2022 and the associated uncertainties as to costs why is it not preferable to address funding for this project through an ICM application made in 2020 (or later)?

b) Since the Garden Avenue facility, Southwork project and Bishop Street renovations and Thompson Drive lease termination are all part of one facilities plan why is it not preferable to apply for all the projects under the ambit of one multi-year ICM proposal at a later date.

VECC-TCQ -62
Reference: Update Evidence December 13, 2018

a) For each Garden Avenue, Southwork, Bishop Street, and Thompson Drive and Dundas Street facilities please provide a table showing the most recent information of:
i) Where applicable - the start date and completion date of construction/renovations (month and year);
ii) The date of occupancy/vacate and number of staff vacating or occupying on this date (month and year). Please provide both the absolute number of staff and the percentage of current staff using facility in question at the time of occupancy/vacate (e.g. 100% of Dundas Street staff on what month and year and how many staff in total)
iii) Current best estimate of cost of project. If detailed estimates have not yet been developed (i.e. Garden Avenue – please provide the current planning estimate).

VECC-TCQ-63
Reference: Update Evidence December 13, 2018, pgs. 6-7

a) Please provide a list of the site approvals that are noted as being delayed.

b) Please provide a list of all approvals required for the Southwork project, noting those that have been received to date and the expected date for outstanding approvals.

c) The evidence states that finalization of the plans for the Southworks facility are pending environmental due diligence. It further states that HIP Developments expects of have a Record of Site Condition for the Ministry of Environment by end of 2018.
i) Is HIP preparing the Record of Site Condition?
ii) Has this Record been filed with the Ministry?
iii) If yes please provide a copy of the Record.
iv) If the Record of Site makes a determination of a concentration of contaminants please indicate when an action plan will be developed to address the contaminants.

d) Was the soil radiation budget (100k) estimated based on a completed Record of Site or was this estimate made prior to environmental work being completed?

e) Has the Committee of Adjustment approved the proposed severance required or the Southworks project? If not please provide the hearing date for this application.

VECC-TCQ - 64
Reference: Update Evidence December 13, 2018, pg. 16

Preamble: In the updated evidence it states: "*Energy+ did not experience a reduction in bad debt expense related to residential customers in 2016 and 2017 and therefore has not made any adjustments for bad debts*."

In response to 4-Staff-59 E+ states:

Billing and collecting expenses were forecast to be lower for 2017 than 2016, predominately as a result of a reduced forecast for Bad Debt Expense. In 2016 a large commercial account filed for bankruptcy, resulting in a higher bad debt expense. Bad debt expense was $527,589 in 2016 compared to the 2017 forecast of $282,004, *representing a forecast reduction of $245,585 (Please refer to Exhibit 4, Table 4-14 Bad Debt Expense).*

Billing and Collecting expenses are forecast to be 1% lower for 2018, than 2017 as a result of departmental account increases and decreases forecast across the multiple department accounts, resulting in a net decrease of $(18,392) over a $3,372,867. forecast budget.

Further Table 4-14 (Exhibit 4, pg.37 – below) appears to show a drop in bad debt as compared to the 2014 proxy).

Table 4-14: Bad Debt Expense

	2014 BA Former CND	2014 BA Former BCP	2014 BA Proxy	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Actual	2018 Actual
Bad Debt Expense	212,000	76,933	288,933	511,688	292,731	527,589	282,004	248,660	249,424
Year over Year Increase (Decrease)					(218,957)	234,858	(245,585)	(33,344)	764
Change in Bad Debt Expense - 2019 Test Year vs. 2014 Board Approved Proxy									(39,509)

a) In light of this prior evidence apparently showing a decline in bad debt costs please clarify what evidence is being relied upon for the conclusion that monthly billing has not led to a reduction in bad debt. Specifically please provide the bad debt expenses for 2014 (proxy) to 2018 for the residential class of customers. If any GS customers have moved to monthly billing since 2014 please provide the bad debt amounts for that class(s) separately.

VECC-TCQ - 65

Reference: Update Evidence December 13, 2018, pg. 28

a) Please explain the nature of the $21,057 in “Other expenses” related to the move to monthly billing?

Issue: 3.2 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?

VECC TCQ-66

Reference: VECC 47
Settlement Proposal – Load Forecast Model, Summary Tab, Rate Class Energy Model Tab and Rate Class Load Model Tab

OEB Cost Allocation Review Report – Board Directions on Cost Allocation Methodology for Electricity Distributors (RP-2005-0317), pages 30-31

a) Please confirm that for the Embedded Distributor customer classes, Energy+'s proposal is to base the load forecast for 2018 and 2019 on 2017 actuals.
b) With respect to the Rate Class Load Model Tab, please review the formulae used to determine the 2018 and 2019 forecast kW for Hydro One-#1-BCP, as the formula appears to incorrectly reference the 2017 energy for HON-CND, and confirm whether or not a correction is required.

c) Please confirm that the Energy+ feeders used to supply the following Embedded Distributors also supply other Energy+ customer classes: i) Waterloo North-CND, ii) HON-CND, iii) Brantford Power-BCP and iv) HON #1-BCP?

d) Please confirm that in accordance with the Board's Cost Allocation Review Report, these feeders are not eligible for direct allocation as, in each case, the feeder is not 100% dedicated to customer(s) in the same classification.

e) Based on the actual 2017 loads, please provide the 4NCP and 12 CP values for each of the five embedded distributors.

VECC TCQ -67

Reference: Exhibit 1, pages 182-184
Exhibit 8, pages 16-18 and Settlement RTSR Workforms
Settlement Proposal – Load Forecast Model, Summary Tab

a) Please confirm that Energy+ receives transmission (i.e., >50 kV) connection services in the following ways: i) from TSs owned by Hydro One Networks-Transmission (e.g. the Preston TS, Galt TS, Brant TS and Brantford TS) for which it is billed Transmission Connection charges by the IESO, ii) from its host distributors (Hydro One Networks-Distribution and BPI) for which it is billed RTSR-Connection charges by the host distributors and iii) from TSs owned wholly or partly by Energy+ (e.g., MTS#1 and the Power Line MTS) for which the costs are included in Energy+'s distribution revenue requirement.

b) Please confirm that in deriving its proposed RTSR-Connection rates Energy+ included all of the forecast load for each customer class. If not, what loads were excluded and why?

c) For each customer class, please provide a breakdown of the forecast 2019 kWh (and kW where applicable) as between that served by Energy+ owned TSs versus that not served by Energy+ owned TSs.

VECC TCQ-68

Reference: Settlement Cost Allocation Model, Tabs I9 and O4

a) Please confirm that the costs associated with >50 kV facilities (i.e., Accounts 1805-1, 1808-1 and 1815) are allocated to all customer classes except the Embedded Distributor classes.

b) Please confirm that the costs in these accounts represent the Energy+ costs associated with MTS#1 and the Power Line MTS. If not confirmed, please explain what facilities the costs are associated with.

c) Please confirm that for purposes of allocating these costs the total 12CP value for each customer class (except the Embedded Distributors) is used (including loads not served by >50 kV facilities owned by Energy+).

VECC TCQ -69

Reference: Settlement Proposal – Cost Allocation Model
Settlement Proposal – Revenue Requirement Work Form
Settlement Proposal – Tariff Schedules and Bill Impacts

a) Please provide a revised Cost Allocation with the following changes:
   i. No direct allocation of costs to the Embedded Distributor customer classes. All costs allocated using the Board's cost allocation methodology and the appropriate allocators.
   ii. Allocate the costs associated with >50 kV facilities to all customer classes, including the five Embedded Distributor classes.

b) Based on the results from part (a) and Energy+'s proposed approach for adjusting Revenue to Cost ratios and designing customer class rates, please provide:
   i. A revised Tab 11 per the Revenue Requirement Work Form
   ii. The resulting bill impacts for the BCP and CND service areas.

VECC TCQ-70 (Revised)

Reference: Settlement Proposal, Cost Allocation Model, Tabs I4 and E4

Preamble: A portion of E+'s primary and secondary distribution system is underground and a portion of it is overhead.

a) Is it reasonable to view the use of underground primary distribution assets (i.e., Accounts 1840 and 1845) versus overhead primary distribution assets (i.e., Accounts 1830 and 1835) as alternative means of providing Energy+'s customers with primary distribution service? If not, why not?

b) More specifically is it reasonable to view:
   i. The use of primary overhead wire/conductors (i.e., Account 1835) as an alternative to the use of primary underground conductors (i.e., Account 1845), and
   ii. The use of primary pole/towers (i.e., Account 1830) as an alternative to the use of primary underground conduit (i.e., Account 1840)?

   If not, why not?

c) With respect to Energy+'s primary distribution facilities, what determines whether a particular customer is served using overhead (Accounts 1830 and 1835) or underground (Accounts 1840 and 1845) facilities?

d) Are any of Energy+'s primary voltage customers served solely by primary underground conductor and conduit (i.e., no overhead lines used)?

e) Are any of Energy+'s customers served solely by primary overhead facilities (i.e., overhead conductors and poles/towers)?

f) Please confirm that for purposes of allocating those accounts associated with overhead assets (Accounts 1830 and 1835), the total load for each customer class is used regardless of whether overheard facilities, underground facilities or a combination of both are actually used to deliver the load (with the exception of the Embedded Distributors where direct allocation is applied).

g) Please confirm that for purposes of allocating those accounts associated with underground assets (Accounts 1840 and 1845), the total load for each customer class is used regardless of whether overheard facilities, underground facilities or a combination of both are actually used to deliver the load (with the exception of the Embedded Distributors where direct allocation is applied).

h) Can Energy+ provide a breakdown, for each customer class, of the load (kWh) served by overhead versus underground primary distribution facilities (i.e., Accounts 1830 &1835 versus 1840 & 1845)? If so, please do so.

i) Please comment on the merits (i.e., from both a practicality and fairness perspective) of allocating: i) the cost of overhead facilities based solely of the portion of the load for each customer class that is served using overhead facilities and ii) the cost of underground facilities based solely on the portion of the load for each customer class that is served using underground facilities.

VECC TCQ -71 (Revised)

References: Energy+ response to TMMC April 10, 2018 Question 10, Sub-Question I
TMMC-11

a) In the response to Question 10, Sub-Question I, Energy+ stated: "The assets used exclusive to TMMC would mainly be the 795MCM aluminum wire and associated clamps/bracket/insulators/bolts along with two TMMC specific load break switches and a few solid blade switches. Energy+ has recorded the costs of these assets in the Overhead Conductors and Devices assets category on a pooled asset basis and therefore the asset value, net book value, and annual depreciation expense for these exclusive assets is not specifically available".

   Given this response, please explain how the values provided in Energy+ response to TMMC-11 were determined. In responding please indicate whether the asset values are those directly attributable to the specific assets used exclusively by TMMC or whether values have been "estimated". If the latter, please describe how the estimation was done.

b) Apart from these assets, are there any other assets recorded in Account 1835 (Overhead Conductors and Devices) that are used (on a shared basis) to provide service to TMMC? If yes, please describe what the assets are.

VECC TCQ -72 (Revised)

Reference: TMMC-11
Settlement Proposal – Cost Allocation Model

a) Please provide a revised version of the Cost Allocation Model filed with the Settlement Proposal where:

i. The costs of the assets in Account 1835 that are exclusively used by TMMC are directly allocated to the Large User class. (Note: If Energy+ views that the costs in Account 1835 that should be directly allocated to TMMC differ from those identified in the response to TMMC-11, please utilize the updated costs and explain how they were derived)
ii. TMMC load is included in the allocation of costs to the Large User class for all of the accounts except 1835 and 1845.
iii. There is no direct allocation of costs to the Embedded Distributor customer classes. All costs allocated using the Board's cost allocation methodology and the appropriate allocators.
iv. The costs associated with >50 kV facilities are allocated to all customer classes, including the five Embedded Distributor classes.

b) Based on the results from part (a) and Energy+'s proposed approach for adjusting Revenue to Cost ratios and designing customer class rates, please provide:
   i. A revised Tab 11 per the Revenue Requirement Work Form
   ii. The resulting bill impacts for the BCP and CND service areas.

c) If Energy+ does not view the revisions requested under items (ii), (iii) and/or (iv) to be appropriate, please also provide an alternative Cost Allocation model reflecting Energy+'s preferred methodology.

d) Based on the results from part (c) and Energy+'s proposed approach for adjusting Revenue to Cost ratios and designing customer class rates, please provide:
   i. A revised Tab 11 per the Revenue Requirement Work Form
   ii. The resulting bill impacts for the BCP and CND service areas.

VECC TCQ -73

Reference: TMMC Response to VECC 17.1

a) TMMC's response to VECC 17.1 states: "In general, a rate classification should be comprised of customers with similar load characteristics". Does Energy+ agree with this statement and with the resulting implication that separate rate classifications should be created for customers with dissimilar load characteristics?

b) If yes, what "load characteristics" should be considered?

c) If yes, are there any other factors (apart from load characteristics) that should be also used in determining whether customers should be in the same or separate rate classifications?

d) If no, what factors should be used in determining whether customers should/should not be in the same rate classification?

e) Is Energy+ aware of any Ontario Energy Board decisions, direction or policies that indicate when customers should or should not be included in the same rate classification?

VECC TCQ -74

Reference: TMMC Response to Staff 1 b)

Exhibit 7, pages 3-4

Preamble: Energy+ current Large Use rate class has two customers: TMMC and one other. Staff Interrogatory 1 b) to TMMC requested a cost allocation model with TMMC as a separate class.

a) Does Energy+ agree that there is likely some diversity in the timing of peak loads of its two Large Use customers such that the sum of the 4NCP values for the each of the two customers is likely to exceed the 4NCP value for the current Large Use class? If not, why not?

b) Using 2016 actual data (as described on pages 3-4 of Exhibit 7) or more recent 2017 data if it is available for the Large User rate class, please provide:
   i. The 4NCP value for the current Large User rate class (unadjusted for Standby),
   ii. The 4NCP value for TMMC (unadjusted for Standby), and
   iii. The 4NCP value for Energy+ other Large Use customer.

c) Recognizing that some of the data requested in part (b) is likely confidential, please also provide:
   - The ratio of the 4NCP value for TMMC (item (i)) to the 4NCP value for the current Large User rate class (item (iii)).
   - The ratio of the 4NCP value for the other Large User (item (ii)) to the 4NCP value for the current Large User rate class (item (iii)).

VECC TCQ -75 (Revised)

Reference: TMMC Response to Staff 1 b)

Settlement Proposal – Cost Allocation Model

a) Please provide a revised version of the Cost Allocation Model filed with the Settlement Proposal where:
   i. TMMC is included as a separate customer class and the demand allocators for the two new Large User classes are determined as follows:
      - 12CP for each class (prior to the Standby Adjustment to the TMMC allocator) is determined by multiplying the current 12CP demand allocator for the Large User class by each customer's relative contribution to the actual 12CP value for the current Large User class (using either 2016 or, if available, 2017 actual data) and then making the necessary Standby Adjustment.
      - 4NCP for each class (prior to the Standby Adjustment to the TMMC demand allocator) is determined by applying the ratios calculated in the preceding question to the 4NCP value (prior to the Standby Adjustment) for the current Large User class and then making the necessary Standby Adjustment.
   ii. The costs of the assets in Account 1835 that are exclusively used by TMMC are directly allocated to the Large User class. (Note: Again, if Energy+ views that the costs in Account 1835 that should be directly allocated to TMMC differ from those identified in the response to TMMC-11, please utilize the updated costs.)
   iii. TMMC load is included in the allocation of costs for all of the accounts except 1835 and 1845.
   iv. There is no direct allocation of costs to the Embedded Distributor customer classes. All costs allocated using the Board-approved cost allocation methodology and the appropriate allocators.
   v. The costs associated with >50 kV facilities are allocated to all customer classes, including the five Embedded Distributor classes.

b) Based on the results from part (a) and Energy+'s proposed approach for adjusting Revenue to Cost ratios and designing customer class rates, please provide:
   i. A revised Tab 11 per the Revenue Requirement Work Form
   ii. The resulting bill impacts for the BCP and CND service areas.

c) If Energy+ does not view the revisions requested under items (iii), (iv) and/or (v) to be appropriate, please also provide an alternative Cost Allocation model reflecting Energy+'s preferred methodology.

d) Based on the results from part (c) and Energy+'s proposed approach for adjusting Revenue to Cost ratios and designing customer class rates, please provide:
   i. A revised Tab 11 per the Revenue Requirement Work Form
   ii. The resulting bill impacts for the BCP and CND service areas.

VECC TCQ-76

Reference: Settlement Proposal – Cost Allocation Model

a) Please confirm whether the cost allocation methodology used in the Cost Allocation Model filed with the Settlement Proposal represents Energy+'s cost allocation proposal for purposes of setting 2019 rates.

b) If not confirmed, please outline the changes that Energy+ would make and provide an alternative cost allocation model that incorporates these changes.

c) If an alternative cost allocation is provided in response to part (b), then based on the results from part (b) and Energy+'s proposed approach for adjusting Revenue to Cost ratios and designing customer class rates, please provide:
   i. A revised Tab 11 per the Revenue Requirement Work Form
   ii. The resulting bill impacts for the BCP and CND service areas.

Issue: 3.5 Are the proposed Retail Transmission Service Rates and LV Rates appropriate?

VECC TCQ -77

Reference: Exhibit 8, pages 22-23
Staff 90

a) Please provide a schedule that sets out the revenues Energy + receive from LV charges for each of the years 2015-2017.

b) Given there is a minimal difference between the 2017 actual load and the 2019 load forecast, please explain why applying the 2017 RTSRs to the 2019 load forecast results in a 46% increase (i.e., from $550,853 to $806,325) in LV costs.

VECC TCQ -78

Reference: Exhibit 8, page 18
Settlement Proposal, RTSR Harmonized
OEB Filing Requirements, Chapter 2, page 55

a) Please confirm that all customer classes, including the Embedded Distributors are assessed RTSR charges.
b) Given that the Filing Requirements call for the "allocation of forecasted LV costs to customer classes (generally in proportion to transmission connection rate revenues)", please explain why the Embedded Distributors were not included in the allocation of LV costs.

VECC TCQ -79

Reference: Staff 88
Staff 64 – Energy + CND LRAMVA Workform, Tab 9
Energy +_Exh1 Response_Addn Cust Questions_April 10, 2018
Settlement Proposal, Load Forecast Model, Rate Class Load Model

Preamble: Energy + proposes to use Gross Load billing for its LV rates.

a) Please confirm that Energy + is billed for LV services by both Hydro One and Brantford Hydro.

b) Please confirm that, for purposes of determining the proposed LV rates, Energy + used the 2019 Large User forecast that included an adjustment for Standby of 30,443.08 kW which was based on 2017 actual data.

c) Does Brantford Hydro use Gross Load billing for its LV charges to Energy +? If not, how does Energy +'s proposal to use Gross Load Billing for its LV charges reflect this fact?

d) Does Hydro One Networks use Gross Load billing for its LV (ST) charges to Energy+, only if the customers with LDG are served via Hydro One Networks' ST facilities? If yes, how does Energy +'s proposal to use Gross Load Billing for its LV charges reflect this fact?

e) The response to the April 10, 2018 Additional Customer Question 5 (iii) indicates that Energy + expects to have additional load displacement generation installed by the end of 2018 with capacity as low as 30 kW. Does Energy +'s proposal to use Gross Load billing for its LV rates apply to all load displacement generation regardless of size? If not, to what size of load displacement generation will Gross Load billing for LV rates apply?

Issue: 3.6 Is the proposal for using gross load billing for Retail Transmission Rates for customers who have load displacement generation appropriate?

VECC TCQ -80

Reference: Staff 88
VECC 54
Staff 64 – Energy + CND LRAMVA Workform, Tab 9
Energy +_Exh1 Response_Addn Cust Questions_April 10, 2018
Settlement Proposal, Load Forecast Model, Rate Class Load Model

Preamble: Energy + proposes to use Gross Load billing for its RTSRs.

a) Please confirm that, for purposes of determining the proposed RTSRs, Energy + used the 2019 Large Use forecast that included an adjustment for Standby of 30,443.08 kW based on 2017 actual data.

b) Please confirm that, based on actual 2017 data, the demand adjustment for the Gross Load Billing method would be 74,376 kW (i.e., 6,198 kW x 12 per Staff 64 – Energy + CND LRAMVA Workform, Tab 9). If not confirmed, what would be the adjustment based on 2017 actual data and how is it derived?

c) Please confirm that, if the RTSRs are to be based on Gross Load billing (as proposed by Energy +) then the Large User load forecast for 2019 should be adjusted by the amount identified in the response to part (b) and not 30,443.08 kW.

d) The response to the April 10, 2018 Additional Customer Question 5 (iii) indicates that Energy + expects to have additional load displacement generation installed by the end of 2018 with capacity as low as 30 kW. Does Energy +'s proposal to use Gross Load billing for its RTSRs apply to all load displacement generation regardless of size? If not, to what size of load displacement generation will Gross Load billing apply?

Issue: 3.7 Is the proposal for implementing a standby charge for the Large Use, GS 1,000 to 4,999 kW and GS 50 to 999 kW customer classes with load displacement appropriate?

VECC TCQ –81

Reference: Energy+ Response to TMMC-14, part 5

TMMC Response to VECC IR #18
TMMC Response to Staff #1 d)

a) TMMC-14 requested information regarding Energy+'s Cambridge system. Please clarity how Energy+ has defined the "Cambridge System" for purposes of the response. In particular, how does this differ from the portion of Energy+'s system that is served by the Preston TS?

b) With respect to the excel file provided in response to TMMC-14, part 5, please explain what the columns System Peak (col. E) and Sys Peak with Generation (col. F) represent.

c) For each of the days/ending hours identified in TMMC-14, part 5, please indicate whether the hour concerned is an on-peak or off-peak hour based on the definition of on-peak provided in TMMC's Response to VECC IR #18.

d) For each of the months identified in TMMC-14, part 5, please indicate the peak hour (i.e., day and hour ending) for the Preston TS serving TMMC and whether than hour was in the on-peak or off-peak period.

e) The response by TMMC to Staff 1 d) indicates that Energy+ has access to the hourly metered data for TMMC's LDG. Please indicate the generation output of TMMC's LDG, at the time of each of the monthly hours identified in response to TMMC-14, part 5 (i.e., the time of the Cambridge system peak).

f) If the definition of the Cambridge system differs from the portion of Energy+'s system served by the Preston TS, then please also indicate the generation output of TMMC's LDG, at the time of each of the monthly hours identified in response to part (d) (i.e., the time of the Preston TS peak).

VECC TCQ -82

Reference: TMMC 16
Staff 77
Energy +_Exh1 Response_Addn Cust Questions_April 10, 2018

a) The response to Staff 77 states that it is Energy+'s proposal to offer standby rates to all customer with installed LDG (in the noted customer classes). The response to the April 10, 2018 Additional Customer Question 5 (iii) indicates that Energy + expects there will be customers that have additional load displacement generation by the end of 2018 with capacity as low as 30 kW. Please confirm that if the customer concerned was in one of the noted classes then the Standby rate proposal would apply to the customer with the 30 kW LDG facility. If not, why not?

VECC TCQ -83

Reference: Staff 77
Staff 78
SEC 39

a) The responses to Staff 77 b) (3rd bullet) and Staff 78 suggest that a customer with LDG has the option of <u>not</u> contracting for Standby (on the basis that the customer does not require backup supply from Energy + when its LDG is inadequate) and, therefore, <u>not</u> establishing a "contracted capacity" value. Furthermore, the response to SEC 39 suggests that a customer with LDG can opt out of its Standby contract. Please confirm if this is the case.

b) If this is the case and the customer makes the determination that it will not contract for Standby, please address the following:
   i. Are there circumstances under which Energy+ would not accept the customer's determination and require the customer to contract for Standby and establish a contract quantity? If yes, what are the circumstances and what is the minimum contract quantity Energy+ would deem appropriate?
   ii. If the customer opts for no Standby contract (and Energy+ accepts), how would Energy + determine, on an ongoing basis, that the customer has not subsequently required standby to supplement its own LDG?
   iii. Furthermore, under the circumstances outlined in part (ii), if Energy + determines that the customer has effectively required Standby, will Energy+ require the customer to contract for Standby and what is the minimum contract quantity that Energy+ would deem appropriate?

VECC TCQ -84

Reference: Energy+ Response to TMMC April 10, 2018 Question 7, Sub-Questions II & III
Staff 77 h)

Preamble: The response to Sub-Question II indicates that Energy+ is willing to accept reasonable proposals from customers with LDG regarding the contract capacity and to negotiate with customers in that regard. Staff 77 h) indicates the customer is expected to provide an estimate for the contracted capacity. The response to Sub-Question III indicates that there will be no penalty provisions if the agreed upon contract capacity is subsequently proven to be too low and revised upwards.

a) Given this context, what is the incentive for the customer to provide a realistic estimate of the required contracted capacity, when the customer will "benefit" from providing/negotiating a value that is unrealistically low until such time as it is proven to be so, with no subsequent penalty (i.e., the contract quantity will be revised upwards to a more realistic value but then the higher value is only applied on a going forward basis)?

b) Is there a minimum contract capacity value that Energy+ would deem to be appropriate and, if so, what would it be based on?

VECC TCQ -85

Reference: Energy+ Response to TMMC April 10, 2018 Question 7, Sub-Questions I & II
Staff 78
IR-TMMC 5

a) The responses to Sub-Question II, Staff 78 and TMMC 5 all indicate that Energy + is willing to consider reasonable proposals from TMMC on how the capacity level should be set as a starting point. Indeed, the response to Sub-Question I suggests that the capacity level included in the Application reflected the fact that there was no feedback from TMMC on this issue. As of the current date, has Energy+ further sought/received feedback from TMMC as to its estimate of the required contract capacity and/or has Energy+ participated in any negotiations with TMMC as to what would be a reasonable contracted capacity value? If yes, what is the outcome to date?

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