ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application to the Ontario Energy Board by Energy+ Inc. pursuant to Section 78 of the *Ontario Energy Board Act* for approval of its proposed distribution rates and other charges effective January 1, 2019.

CONTAINS CONFIDENTIAL INFORMATION

Toyota Motor Manufacturing Canada Inc. ("TMMC")

Responses to Interrogatories

of

Energy+ Inc. (Energy+)

October 25, 2018

Exhibit 1

1-EnergyPlus-1

Reference: **Written Evidence of Melody Collis (Toyota Motor Manufacturing Canada Inc.) dated September 27, 2018 (the "Ms. Collis Affidavit") at page 6, lines 88 to 103.**

Preamble: "Q.6 When and why did TMMC decide to install the CHP Facility?

A. The CHP Facility went into operation on January 1, 2016. TMMC's decision to invest $27 million in a CHP Facility was driven by a number of different factors, including:

- our desire to increase our energy efficiency and realize cost savings, helping TMMC to stay competitive within the global manufacturing landscape;
- our desire to meet Toyota's corporate "Environmental 2050 Challenge" which sets targets that will help Toyota realize its global sustainable development goals; and
- our desire to benefit the community in which we are located by reducing TMMC's demand and freeing up energy for our neighbours to use.

TMMC worked closely with Cambridge Hydro during the planning and development phase of the CHP Facility. During that time, Mr. Ian Miles, the Chief Executive Officer and President of Energy+, was quoted in the press as saying "[T]hrough this collaboration, our community will benefit from improved system reliability and avoided power generation costs. Toyota's leadership has been pivotal to the success of working towards meeting our mandated energy and demand reduction targets."

Questions:

(a) Confirm that Toyota Motor Manufacturing Canada Inc. ("TMMC") knew that a standby power charge was likely to be applied to any self-generated electricity prior to investing in its self-generation facility.

(b) Provide the final CEM Engineering report to TMMC titled "Technical Report - Detailed Engineering Study of Self-Generation" dated November 16, 2012 described as "Final Report to the OPA" (the "CEM Engineering Report").

(c) Confirm that the CEM Engineering Report forecasted changes in costs arising from the installation of self-generation would result from, inter alia, the introduction of a standby power charge, which was estimated at $[redacted]]/year.

(d) Confirm that the CEM Engineering Report estimated a simple payback period of [redacted] years for the self-generation, without any incentives, and a simple payback period of [redacted] years for the self-generation, with incentives.

(e) Please update the table provided at Section 1.4 of the CEM Engineering Report to provide an updated payback period calculation associated with the TMMC self-generation, based on (and providing to the OEB) actual total costs ($), actual participant incentives received ($), actual electricity cost savings accrued ($ for each of 2016, 2017 and 2018 year to date), actual other net costs ($ for each of 2016, 2017 and 2018 year to date), and actual net savings ($ for each of 2016, 2017 and 2018 year to date).

Responses:

(a) TMMC does not confirm that it knew that a standby power charge was likely to be applied to any self-generated electricity, prior to investing in its CHP Facility. While TMMC's own consultants advised that some Ontario utilities imposed such charges on their LDG customers, Cambridge and North Dumfries Hydro (as it then was) did not advise TMMC of any intention to pursue a standby charge proposal. Indeed, its cost of service application for 2014 rates filed on October 1, 2013, did not include a standby rate proposal.

(b)-(e) TMMC declines to respond to these questions on the basis that planning and pay-back assumptions included in a TMMC engineering report from 2012 are not relevant to the issues in this proceeding, including the issues raised by Ms. Collis in her evidence.

1-EnergyPlus-2

Customer Engagement

References: **Ms. Collis Affidavit at page 8-9, lines 149 to 157.**

Exhibit 1, Appendix 1-16 Customer Engagement, Customer Meeting October 18, 2017

Energy+ Response to TMMC Interrogatories at Appendix IR-TMMC-19

Preamble: **"**Q.11 Why is TMMC participating in this proceeding?

A. Energy+'s proposal includes two proposals, which approved, would affect what TMMC pays for distribution service. The first is a proposal to implement a Standby Rate that would also be applicable to customers in the Large Use Class who have load displacement generation ("LDG") facilities and who require Energy+ to provide additional distribution service during planned or unplanned outages of their LDG facility. The second is a proposal to adjust its Retail Transmission Service Rates- Connection to reflect the pass-through of Hydro One connection charges on a gross, rather than a net load basis for customers with embedded distribution facilities ("**Gross Load Billing**")."

"Q.12 When did TMMC first learn the details of the Application and the rate proposals that would affect TMMC?

A. TMMC first learned of details pertaining to the Application at a customer engagement meeting with representatives of Energy+ on January 19, 2018."

Questions:

(a) Confirm that a meeting was held on November 6, 2014 between TMMC and the former CND representatives, which included a presentation and discussion with respect to the utilization of gross load billing for load displacement generation.

(b) Confirm that Energy+ attended a meeting at TMMC on October 18, 2017 and that the meeting agenda included an update on Energy+'s Cost of Service Application and a Regulatory Update. Please confirm the regulatory update PowerPoint presentation that was provided by Energy+ to representatives of TMMC for this meeting is available on the evidentiary record at Exhibit 1, Appendix 1-16 (starting at page 1057). Confirm whether or not the slides in this October 2017 presentation, include a slide on the rate design options that Energy+ was considering, which specifically included: (i) implementation of a standby charge; and (ii) use of gross load billing for certain charges.

(c) Does TMMC wish to clarify the evidence that it has provided with respect to the dates upon which TMMC first learned of Energy+'s proposals?

(d) Confirm whether any TMMC representative contacted Energy+ for further information and/or clarification between the period October 19, 2017 and January 19, 2018. If no, why not?

Responses:

(a) A meeting between TMMC and former CND representatives was held on November 6, 2014 and a presentation that referred to gross load billing was made by CND representatives. Neither Ms. Collis nor any other current TMMC employee can confirm or deny what may have been discussed at a meeting that occurred four years ago. We note that at the time, there were multiple technical meetings between TMMC and Energy+ where multiple issues were discussed.

(b) A meeting between TMMC and Energy+ did occur on October 18, 2017, at Ms. Collis' request. The purpose of the meeting was to discuss operational and technical matters. Energy+ took the opportunity to present a regulatory update, which included mention of its plans to consider standby charges and gross load billing (specifically, refer to pp. 1065 and 1066 of Exhibit 1, Appendix 1-16 of Energy+'s Application). No specific proposal was presented or discussed.

(c) It does not. Ms. Collis's evidence is that TMMC first learned of details pertaining to the Application on January 19, 2018. No plan, proposal or details of a plan or proposal on standby charges or gross load billing were presented to TMMC before the January meeting.

(d) The October 18, 2017 presentation by Energy+ indicated that Energy+ was continuing to investigate methodologies, create comparisons and evaluate options and impacts having to do with standby charges. The presentation ended with the statement that Energy+ would hold "[C]ustomer meetings over the next six weeks to solicit formal feedback on proposal and options considered". This did not occur.

1- EnergyPlus-3

Customer Engagement

Reference: **Ms. Collis Affidavit at page 14, lines 282 to 290.**
Energy+'s Customer Engagement, page 9

Preamble: In its written evidence, TMMC states that

"The result of late engagement with TMMC was that there was insufficient time, from the date of the first meeting (January 19, 2018) to the date the Application was filed with the Board at the end of April, 2018 for a comprehensive and meaningful consultation where TMMC would have been able to propose changes to Energy+'s proposals that addressed issues and concerns. Such consultation could have served to reduce areas of misunderstanding and disagreement.

TMMC also indicates that:

"Energy+ declined TMMC's request to review a draft of the Application prior to the formal filing of the Application with the Board."

Questions:

(a) Confirm that TMMC was made aware by Energy+ that its Application was due to be filed with the Ontario Energy Board by the end of April 2018.

(b) On what date did TMMC formally request a copy of Energy+'s complete rate application for review?

(c) Confirm that Energy+ responded to TMMC's request on April 9, 2018 via email and that Energy+ provided the following response:

"We would be happy to answer any further questions that TMMC has with respect to the Cost of Service Application. The Application is due to the filed with the Ontario Energy Board by April 27, 2018 and we are on track to meet this timeline. As of this date, we have received no further feedback from TMMC, other than at the meeting held on January 19th, 2018. In our Customer Engagement feedback, we will indicate that we actively engaged with our 5 MW+ customers (a customer's identity is not disclosed in the Application) and did not receive specific feedback with respect to our proposal from one of the customers. With respect to the Standby/Capacity Charge, we will be putting forward the proposal as outlined in our presentation on January 19, 2018 with the proposed capacity based on [redacted] kW per month.

With respect to sharing the draft Application, it is still a work in progress. I will forward you the link of the final and complete Application once it is filed, and made available for public review."

(d) Confirm that Energy+ directly provided to TMMC a final copy of the Energy+ Application on May 7, 2018.

(e) Confirm that Energy+ has responded to multiple rounds of questions from TMMC on its proposal, including:

- Energy+ responses to certain follow-up questions arising from a call dated February 16, 2018 (filed as part of Exhibit 1, pages 1116-1145);
- Energy+ responses to additional "interrogatory" questions filed with the OEB on July 10, 2018;
- Energy+ responses to TMMC interrogatory questions, filed September 14, 2018; and
- Energy+ responses to TMMC clarification questions, filed September 19, 2018.

Responses:

(a) Confirmed.

(b) April 4, 2018.

(c) Confirmed. From Energy+'s April 9th response, it is clear that it did not wish to share the final details of its Standby Charge proposal with TMMC until it had been filed with the Board.

(d) Confirmed.

(e) TMMC submitted two sets of questions to Energy+, prior to the April 27th filing of the application. The first set was conveyed on a call on February 16, 2018; Energy+ provided written responses on February 27, 2018. TMMC then submitted a detailed set of written questions on April 12, 2018. Energy+ provided written responses on July 10, 2018.

Exhibit 7

7-EnergyPlus-4

Reference: Written Evidence of Jeffry Pollock on behalf of Toyota Motor Manufacturing Canada Inc. September 27, 2018 (the "**Mr. Pollock Evidence**") at page 30, Table 4 TMMC's Revised CCOSS Results Revenue Requirement

Preamble: Table 4 of the Mr. Pollock Evidence provides "TMMC's Revised CCOS Results Revenue Requirement by class".

The following table attempts to show the difference between Energy+ Updated and TMMC Revised columns:

TMMC's Revised CCOSS Results Revenue Requirement ($000)

Rate Class	Energy+ Updated	TMMC Revised	Difference
Residential	$22,723.2	$23,698.4	$975.2
GS < 50 kW	$4,118.2	$4,116.7	($1.5)
GS: 50 – 999 kW	$5,638.1	$5,312.0	($326.1)
GS: 1,000 – 4,999 kW	$2,013.2	$1,778.4	($234.8)
Large Use	$1,108.2	$659.1	($449.1)
Street Light	$494.6	$516.2	$21.6
Sentinel	$23.4	$24.9	$1.5
Unmetered Load	$78.3	$91.3	$13.0
Hydro One 1 CND	$43.1	$43.1	$0.0
Waterloo No. CND	$156.4	$156.4	$0.0
Hydro One BCP	$30.2	$30.2	$0.0
Brantford Power	$12.8	$12.8	$0.0
Hydro One 2 BCP	$3.0	$3.0	$0.0

Source: Energy+ 2019 Cost Allocation Model (Updated September 14, 2018), Worksheet O1 and Schedule JP-5, Row 40.

Questions:

(a) Confirm the differences in Revenue Requirement for each class arising from the TMMC Revised case when compared to the Energy+ Updated case, as shown in the above table above, are correct. If not correct, provide a corrected table showing such differences by class.

(b) Explain why the Revenue Requirement has increased from the Energy+ Updated case to the TMMC Revised case for the Residential, Street Light, Sentinel and Unmetered Load classes but has decreased or remained the same for all other classes?

Responses:

(a)&(b) Table 4 in Mr. Pollock's Written Evidence has been revised to reflect two corrections that have been made to Schedule JP-5. The first was to include the PLCC adjustment which had been inadvertently removed in determining the demand allocation factors. The second was a revision to the allocation of the direct assignment feeder costs between demand and customer-related components.

Table 4 Revised
TMMC's Revised CCOSS Results
Revenue Requirement
($000)

Rate Class	Energy+ Updated	TMMC Revised
Residential	$22,723.2	$22,901.3
GS < 50 kW	$4,118.2	$4,180.5
GS: 50 – 999 kW	$5,638.1	$5,825.6
GS: 1,000 – 4,999 kW	$2,013.2	$1,922.8
Large Use	$1,108.2	$769.2
Street Light	$494.6	$495.8
Sentinel	$23.4	$23.4
Unmetered Load	$78.3	$78.5
Hydro One 1 CND	$43.1	$43.1
Waterloo No. CND	$156.4	$156.4
Hydro One BCP	$30.2	$30.2
Brantford Power	$12.8	$12.8
Hydro One 2 BCP	$3.0	$3.0

Source: Energy+ 2019 Cost Allocation Model (Updated September 14, 2018), Worksheet O1 and **Schedule JP-5 Revised**, Row 40**.**

7-EnergyPlus-5

Reference: **Mr. Pollock Evidence at page 8, lines 7 to 10.**

Preamble: In the reference lines it states:

"The 12CP, 4NCP and 12NCP demands used to allocate costs to the Large Use class in the CCOSS do not reflect the load profile of the Large Use class; instead, they reflect a load profile adjusted for the assumed impact of TMMC's LDG facility."

In response to Staff Interrogatories, 7–Staff-84, Page 271 of 875 it states:

"However, in accordance with OEB's Decision in Horizon Utilities Corporation 2015 to 2019 Custom IR application (EB-2014-0002), the OEB did not allow the load profile for one rate class to be updated unless all rate classes were updated."

Similarly, in the Chapter 2 Filing Requirements at Section 2.7.1 it states:

"Recently, the OEB has required that load profiles for all classes be updated at the same time, not just selective updating."

Questions:

(a) Explain whether, and if so how, TMMC proposes to update the load profile for the Large User class as well as the load profiles for the other classes to be consistent with the OEB's Decision in EB-2014-0002?

(b) Please outline which costs are allocated with the 12NCP demand allocator.

(c) Explain why it is stated "the CCOSS do not reflect the load profile of the Large Use class" when in Exhibit 7, section 7.1.2 Load Profiles of the Application it explains that the load profile of the Large Use class is the 2004 load profile scaled to 2019 volumes.

Responses:

(a) TMMC is not proposing to update the load profile for the Large Use class or any other class.

(b) The 4NCP demand allocator is used to apportion primary and secondary distribution plant and related expenses, including underground conduit and conductors. No costs were allocated using the 12NCP demand allocator (see page 19 of the Errata to Mr. Pollock's Evidence).

(c) Energy+'s CCOSS used coincident and non-coincident peak demands derived from the Large Use class 2004 load profile scaled to 2019 volumes, but with adjustments for the assumed coincident and non-coincident peak loads associated with TMMC's load displacement generation (LDG). The adjusted coincident and non-coincident peak demands are not the same as the coincident and non-coincident peak demands derived from the 2004 load profile scaled to 2019 volumes.

7- EnergyPlus-6

Reference: **Mr. Pollock Evidence at page 8, lines 15 to 18.**

Preamble: In the reference lines it states:

"The adjustments to the Large Use class demand allocators also ignore the diversity within the Large Use class. Energy+ assumes zero diversity within the Large Use class (i.e., peak demands occurring at different times)."

Question:

(a) Explain the statement referenced above considering the Large Use load profile reference in Exhibit 7, section 7.1.2 Load Profiles of the Application reflects the diversified load of the customers in the Large Use class.

Responses:

(a) Energy+'s LDG adjustments assume that full Standby service is provided in each and every hour, which recognizes zero diversity between Standby service and the Supplemental service provided to the two Large Use class customers.

7-EnergyPlus-8

Reference: **Mr. Pollock Evidence, page 24, line 10.**

Preamble: In the reference line it states:

"What steps were taken to reflect any diversity of generation in its filing?"

EB-2005-0317, Board Directions on Cost Allocation Methodology for Electricity Distributors (September 29, 2006) at page 22. On page 22 it indicates the referenced diversity is the diversity of the LDG generation within the LDG rate classification as it states on page 22:

"*Some stakeholders have commented that it is unlikely that all load displacement customers within a distributor will be requiring LDG power at the same time and that there will be diversity on the requirement for LDG load within the separate load displacement generation rate classification*."

Question:

(a) Explain whether the question referenced above relates to the same definition of diversity of generation as outlined in the above reference from EB-2005-0317.

Responses:

(a) Yes. As explained in response to 7-EnergyPlus-7, Energy+'s LDG adjustments assumed certainty that all Standby service would be provided at the same time, both during the class's coincident and non-coincident peaks, throughout the year. This assumption ignores the diversity of Standby service provided to the LDG.

7-EnergyPlus-9

Reference: **Schedule JP-5 Confidential Unredacted, Tab I8 Demand Data**

2019 EnergyPlus_Cost_Allocation_Model 7 Staff 76 b_20180914, Tab I8 Demand Data

Response to 7–Staff-85

Question:

(a) Explain why the demand units in Tab I8 are different for the GS> 50- 999 kW and GS> 1,000 - 4,999 kW classes between the two cost allocation models provided in the reference.

Responses:

(a) See Schedule JP-5 Revised.

7-EnergyPlus-10

Reference: **Schedule JP-5 Confidential Unredacted, tab I9 Direct Allocation**

Preamble: In Schedule JP-5 Confidential Unredacted, tab Instructions there are detailed instructions on how to use the OEB's cost allocation model. Specifically information in rows 49 and 50 along with rows 137 to 143 of the Instructions tab provides instructions on how to conduct direct allocation in the model.

Questions:

(a) Confirm whether or not, for each and every one of the above noted instructions, were the instructions followed for direct allocation purposes in Schedule JP-5 Confidential Unredacted.

(b) If they were followed, explain why there were no adjustments made in Tab I3 TB Data, column G for the TMMC directly allocated costs as per the instructions.

(c) If they were not followed, explain why, in detail.

Responses:

(a) Every effort was made to follow the instructions in the model. The instructions for making a direct assignment and then reflecting the impact of the direct assignment were not as intuitive.

(b) The adjustments would sum to zero, as the directly assigned positive costs would have corresponding costs removed from the other rate classes.

(c) Not applicable

7-EnergyPlus-11

Reference: **Schedule JP-5 Confidential Unredacted, tab I9 Direct Allocation**

Preamble: In Schedule JP-5 Confidential Unredacted, tab Instructions row 142 it states:

"*The numerous columns to the right of I-9 are used for the purpose of burdening directly-allocated costs for a share of overhead costs. No inputs are required.*"

Consistent with OEB policy, the OEB's cost allocation model has been designed to burden directly allocated costs for a share of overhead costs.

The information entered in Schedule JP-5 Confidential Unredacted, tab I9 Direct Allocation does not have any data in the numerous columns to the right of I-9 for those costs associated with TMMC directly allocated costs.

Questions:

(a) Explain why there is no data in in the numerous columns to the right of I-9 for those costs associated with TMMC directly allocated costs.

(b) Explain how the burdening of TMMC directly allocated costs has been addressed to include a share of overhead costs.

Responses:

(a) See Schedule JP-5 Revised.

(b) Overhead costs associated with the dedicated feeders are quantified in Schedule JP-3.

7-EnergyPlus-12

Reference: **Schedule JP-5 Confidential Unredacted, Tab I9 Direct Allocation**

Preamble: In Schedule JP-5 Confidential Unredacted, tab I9 Direct Allocation row 171, the TMMC directly allocated OM&A expenses of [redacted] are credited back to other rate classes using an allocation method from Schedule JP-5 Confidential Unredacted, Tab E2 Allocators.

The allocator is shown in row 42 of Tab E2 Allocators and is titled [redacted]

Questions:

(a) Explain why this allocator was used instead of the OM&A allocator shown in Schedule JP-5 Confidential Unredacted, Tab E2 Allocators, row 121 titled "OM&A" allocator to allocate the OM&A expenses of [redacted].

(b) Has Mr. Pollock incorporated any incremental costs in the cost allocation model to reflect the increased operating and/or capital costs with respect to changes to billing process and systems and the regulatory costs associated with the rate design proposal? If not, why not?

(c) Has Mr. Pollock included any of the following other incremental costs directly related to serving TMMC in its cost allocation model, including but not limited to:

(i) Incremental customer engagement costs;

(ii) Incremental engineering costs;

(iii) Incremental billing costs associated with its proposed rate design for the Large User Class and Standby Rate;

(iv) Incremental operating costs associated with the System Supervisory Control and Data Acquisition ("SCADA") system in place for TMMC;

(v) Incremental costs associated with the performance of planned maintenance on adjacent feeders after hours or on weekends to mitigate any risk to TMMC's operations.

If no, would Mr. Pollock agree to incorporate those costs to the extent that they are identifiable and directly attributed to providing service to TMMC?

Responses:

(a) The Operation and Maintenance expense accounts 5020, 5025, 5030, 5095, and 5135 related to the direct assignment and reallocation of the feeders' expense was based on the corresponding demand allocations 1830 & 1835 D, and 1840 & 1845 D as shown on tab E4 TB Allocation Details from Energy+'s CCOSS.

(b) Mr. Pollock used the same class cost-of-service study that was provided by Energy+, which incorporates all of the test year revenue requirements, including costs associated with billing, customer accounting and tariff administration. Mr. Pollock is unaware that his proposed rate design would require any changes with the possible exception of implementing and administering the Daily Volumetric Rate.

(c) Schedule JP-3 includes an allocation of operation and maintenance and general and administrative expenses associated with the facilities that were directly related to serving TMMC. However, to the extent that Energy+ can identify costs in addition to those that were already included in quantifying the direct assigned costs to TMMC, Mr. Pollock would consider them.

7-EnergyPlus-13

Reference: **Schedule JP-5 Confidential Unredacted, Tab E2 Allocators, row 44 and Tab E4 TB Allocation Details, row 44**

Preamble: In the reference rows there is a new allocator titled "PNCP4b" established in Schedule JP-5 Confidential Unredacted, Tab E2 Allocators, row 44 and used in Schedule JP-5 Confidential Unredacted, Tab E4 TB Allocation Details, row 44

Question:

(a) Explain what this allocator represents and what is the source of data used to produce this allocator?

Responses:

(a) See Schedule JP-5 Revised. The allocation factor "PNCP4b" is the PNCP4 allocation factor from Energy+'s CCOS with LDG removed and not adjusted to remove TMMC demands.

7-EnergyPlus-14

Reference: Schedule JP-5 Confidential Unredacted.

Questions:

(a) There have been a number of changes made to the OEB's approved cost allocation model in Schedule JP-5 Confidential Unredacted. Please itemize each of the specific changes that have been made to the original cost allocation model by tab to prepare Schedule JP-5 Confidential Unredacted. For each change, provide an explanation as to why the change was, in your view, necessary.

(b) Outline the detailed steps that were taken in the preparation of Schedule JP-5 Confidential Unredacted to ensure the integrity of the original cost allocation model was not compromised (whether inadvertently or not).

Responses:

(a) See Schedule JP-5 Revised.

(i) **I3 TB Data:** Add lines corresponding to lines added to tab I9 Direct Allocation for the Directly Assigned Feeders expense and reallocation of the expense removed from other classes. Copied necessary formulas from columns D-H.

(ii) **I8 Demand Data:** Input demand data from Schedule JP-4 for the Large Use CP and NCP demands to remove TMMC demands.

(iii) **I9 Direct Allocation:** Add lines and formulas for the Directly Assigned Feeders expense and reallocation of the expense removed from other classes. Allocation and methods shown on excel lines 167-174. Copied formulas to categorize demand and customer of the direct assignment and reallocation of feeders.

(iv) **O1 Revenue to cost|RR**: Changed tab name to "Schedule JP-5 Revised".

(v) **O5 Details by Class & Accounts:** Added column "O1 Grouping".

(vi) **O5 Details by Class & Accounts:** Allocated Plant account Poles, Towers and Fixtures – Primary on 1830-4b allocation.

(vii) **E1 Categorization**: Added line for 1830-4b "Poles, Towers and Fixtures – Primary".

(viii) **E2 Allocators**: Added line for the allocation factor “PNCP4b”. The “PNCP4b” is PNCP4 allocation factors factor from the Company’s study not adjusted to remove TMMC demands. This allocation method allocates cost not directly assigned to TMMC.

(ix) **E4 TB Allocation Details**: Added line for 1830-4b allocation factor.

(b) All of the affected sheets were checked for totals and reference errors.

7-EnergyPlus-15

Reference: **Ms. Collis Affidavit at page 12, lines 249 to 250.**

Preamble: The evidence states the following:

"Third, there is no clarity on how the Contract Demand … a key feature of the proposal … has been established and how it will be adjusted going forward."

Refer to Exhibit 7 and the interrogatory responses (in particular responses to IR-TMMC-3, IR-TMMC-5 and IR 7-SEC-39) for clarity on how the Contract Demand will be established and adjusted going forward.

Question:

(a) Explain exactly what aspects of Energy+'s proposal remains unclear as to how the contract demand has been established and how it will be adjusted going forward.

Response:

(a) Energy+'s standby rate proposal appears to afford it considerable discretion in establishing the Contract Demand amount and in making adjustments going forward. In this regard we note the following:

- Energy+'s response to TMMC-3 states: "Energy+'s proposal is to undertake a review on an annual basis to review the monthly peak loads and, after a discussion with the customer, *possibly adjust* the contracted capacity reserve value". [*emphasis added*]

- Energy+'s response to TMMC-5 states: "The condition noted…was intended to allow for a reasonable proposal from TMMC on the capacity level that is required as a starting point, but to recognize that the acceptance of the proposal could include a condition with respect to the establishment of a new capacity level."

- Energy+'s response to 7-SEC-39 (a) lays out a number of different factors to be considered in making adjustments to contract demand. Its response to 7-39 (b) then lays out a series of steps for dispute resolution, should agreement not be reached. These include discussions with Energy+'s President and CEO and, if that fails to resolve the issue, a suggestion to seek independent advice from the Ontario Energy Board. The number of different factors identified and the proposals for dispute resolution highlight the fact that, as a result of the continued exercise of discretion by Energy+, the basis for adjustment is open to debate and interpretation.

In TMMC's view, all distribution rates should be established in accordance with a clear, objective and transparent methodologies. Rules should clearly articulate how customers' preferences and past consumption patterns will be taken into account in establishing the rate. This will minimize the scope for disagreement and misunderstanding.

7-EnergyPlus-16

Standby Charges

Reference: **Ms. Collis Affidavit**
Energy+'s Standby Rate Proposal at page 12, lines 228 to 235.

Preamble: Does TMMC oppose the imposition of a Standby Rate on Large Use Class customers with LDG facilities?

No, provided the applicable rate is cost-based, non-discriminatory and not subject to change at Energy+'s sole discretion. From our perspective, the rate should also incent TMMC to manage its costs by minimizing its use of standby service and maximize the benefits that the CHP Facility provides to the electricity grid. This involves taking reliability-related steps to minimize the number and duration of outages and scheduling planned maintenance shut-downs during off-peak and shoulder periods.

Questions:

(a) Confirm that TMMC's consultant, Mr. Pollock, has proposed a Standby Rate? Provide a table that directly compares the Standby Rate proposed by Mr. Pollock to the one Energy+ proposed.

(b) Energy+'s proposal for Standby includes the provision that the level of contracted capacity would be reviewed on an annual basis in consultation with the customer. On what basis does TMMC understand that the Standby rate proposed by Energy+ would be subject to change at Energy+'s sole discretion?

(c) With regards to TMMC incentives to maximize the benefits of the CHP Facility, confirm whether TMMC would also be incented through lower electricity commodity costs, lower global adjustment charges, and lower other flow-through costs by minimizing outages and shut-downs during off-peak and shoulder periods.

(d) Provide a percentage breakdown of TMMC's typical monthly electricity bill, broken out to show the percentage of the total bill represented by distribution, transmission, electricity commodity, global adjustment, and other regulatory charges.

(e) What is the estimated annual energy commodity and global adjustment savings that TMMC has achieved by minimizing the number and duration of outages and scheduling planned maintenance shut-downs during off-peak and shoulder periods?

Responses:

(a) Mr. Pollock's Written Evidence includes a proposal for a Standby Rate. Mr. Pollock's proposed rate is underpinned by a base distribution rate design for the Large User Class that is fundamentally different from Energy+'s corresponding rate design. Accordingly, the table requested would be a comparison of "apples and oranges".

(b) Please see our response to 7-EnergyPlus-15.

(c) One of the challenges that TMMC has with respect to operation of the CHP facility is that electricity commodity costs are now made up predominately of Global Adjustment ("GA") costs. As a Class A customer, Toyota's share of GA costs is determined by its electricity demand within only the five hours of peak provincial electricity demand during the year. Outside of these five peak hours, Toyota does not have any impact on its liability for GA costs by operating its CHP unit. <u>In other words, operating the CHP plant outside of these hours has no impact on its share of GA costs, either in the current period or going forward.</u> This has undermined the benefits of operating the CHP because, in most hours, TMMC avoids only Hourly Ontario Electricity Prices (HOEP) with operation of the CHP unit. Because of depressed market prices, HOEP now makes up only about 10-15% of total commodity costs. <u>Further, under the proposal for gross-load billing of transmission charges, as put forward by Energy+, TMMC would also not benefit from reduced transmission charges as a result of operating the CHP facility</u>. Accordingly, the avoidance of distribution charges is an important component of the economics of operating the facility. Further, base distribution and transmission charges are billed on the basis of monthly peak demand. Once a customer has established a particular demand level within a billing period, it has no further incentive to operate a CHP facility as long as demand stays within the envelope already established by the maximum peak value established to-date within that billing period.

<u>In the result, TMMC does not confirm that TMMC has sufficient incentives to minimize outages and shut-downs in the absence of appropriate distribution and standby rate designs. Finally, whether or not there are other incentives that would cause TMMC to minimize outages and shut-downs is not relevant. It is common ground that a properly designed standby rate should incent these behaviours.</u>

(d) TMMC has not prepared such a breakdown. Moreover, Energy+ already possesses the information required to prepare the breakdown that it is requesting of TMMC.

(e) TMMC has not prepared the requested analysis.

7-EnergyPlus-17

Standby Charges

Reference: **Ms. Collis Affidavit**
Energy+'s Standby Rate Proposal at page 12, lines 251 to 253.

Response to IR-TMMC-4

Preamble: "Is Energy+'s Proposed Standby Rate Appropriate?"

"Fourth, the TMMC Contract Demand proposed by Energy+ appears to be punitive because it is based on peak demands established in the summer months. TMMC has a seasonal load profile and draws significantly lower levels of power in the winter months."

Question:

(a) Confirm whether the proposed contracted capacity of [redacted] MW (based on 2017 actuals) occurred in the month of November 2017.

(b) On what basis does TMMC understand that Energy+ has established the peak demand in the summer months?

Responses:

(a) TMMC confirms, based on Energy+'s representations, that the proposed contracted capacity of [[redacted]] MW is based on an actual peak that occurred in the month of November 2017.

(b) TMMC acknowledges that the statement as written is incorrect. It was originally drafted when the proposal from Energy+ reflected a contract demand based on the peak demand in 2016, which was based on demand in a summer month (July 2016).

Although TMMC acknowledges that the quoted statement is technically incorrect, it makes the following additional points:

- TMMC believes that the punitive nature of the rate proposal derives from the intent to bill TMMC throughout the year on the basis of its peak demand in any month during the year. (In other words, the billing determinant for each month in the year will be based for TMMC on the one month with maximum demand.) The punitive nature does not depend on which specific month or season in which this peak demand occurs. This billing approach is punitive because other customers are not billed on the same basis. Thus, TMMC is treated in a discriminatory and disadvantageous basis relative to other customers. Other customers with similar seasonal load profiles will see their distribution charges go down in those months in which they have lower demand, whereas TMMC will not.

- In most years, TMMC's peak demand will most likely be established in a summer month, since TMMC has a seasonal load profile.

7-EnergyPlus-18

Reference: **Mr. Pollock Evidence at page 6, lines 17 to 18.**

Preamble: The evidence states the following: “Q: What instructions were you provided in relation to the issues to be addressed in your evidence?”

Question:

(a) Provide copies of all written or email instructions and correspondence between Mr. Pollock and each of TMMC and Dentons Canada LLP or any other third party advisor to TMMC related to the Energy+ Rate Application.

Response:

(a) Mr. Pollock received instructions from counsel for TMMC. These instructions are set out in his Written Evidence at pp. 6 and 7 of 76. These were the only instructions Mr. Pollock received from anyone regarding the substance and scope of his retainer on behalf of TMMC.

7-EnergyPlus-19

Reference: **Mr. Pollock Evidence at page 8, lines 10 to 14.**

Preamble: The evidence states the following: “This adjustment methodology ignores the principles articulated by the Board to the effect that the first step in allocating total costs to the LDG classification is to determine a proper cost-based rate for providing distribution service to the class, irrespective of the impact of LDG.”

The quote has a footnote which references EB-2005-0317, *Board Directions on Cost Allocation Methodology for Electricity Distributors* (September 29, 2006).

Questions:

(a) Identify exactly which principles articulated in the Board’s Cost Allocation Review (EB 2005 0317) were ignored by Energy+. Provide specific quotes from the document, together with section and page citations.

Response:

(a) The following is a partial list of principles that Energy+ ignored:

- **3.1 Load Data – General Requirements**

  “All distributors are generally expected to provide reasonable supporting data for each separate rate classification to be modeled in Run 1, 2 or 3 of the cost allocation filing.” EB-2005-0317, *Board Directions on Cost Allocation Methodology for Electricity Distributors* at 17 (Sept. 29, 2016).

- **11.5.3 Cost Allocation Methodology Where Existing Load Displacement Customers are Part of a Main Rate Classification (Run 1)**

  “…a useful initial step in determining distribution rates for LDG customers would be use of the new cost-based rate information of other full service customers of similar size. This information will be readily available from filing the model and would be used in Step 1 below.” *Id.* at 93.

- **3.6.3 Filing Questions**

  3) As the load data is based on only one year’s’ experience, indicate whether the load data developed for the load displacement generator customers is considered to be representative of the ongoing performance of the associated generation facilities. *Id.* at 23.

- **8.5.2 Direction — Separate Treatment of Each Rate Class and Subclass for Cost Allocation Purposes.**

  For charges that are based on adjustments to the rates of a main classification (such as most Run 1 USL and LDG rates), diversity will be shared between those customers and the main classification with which they share demand costs. *Id.* at 65.

- **11.5.2.Total Load for Load Displacement Generation Classification**

  11.5.2.1 Background: The total costs to be allocated to the LDG classification will consist of costs associated with providing distribution service to the base load that is the same as the standard distribution customer, along with the distribution costs required to support the incremental load when the load displacement generator is not operating. Id. at 92.

Finally, since Energy+ did not provide a separate cost-of-service run with just a load displacement generation class, this too is in violation of the Board's principles.

7-EnergyPlus-20

Reference: **Mr. Pollock Evidence at page 24, lines 13 to 19 and page 25, lines 1 to 2.**

Preamble: The evidence states the following:

"Q: Is Energy+'s Class Cost of Service Study consistent with the principles articulated by the Board with respect to the allocation of costs to LDG?

A: No, it is not. The Board states as follows:

"The total costs to be allocated to the LDG classification will consist of costs associated with providing distribution service to the base load that is the same as a standard distribution customer, along with the distribution costs required to support the incremental load when the load displacement generator is not operating."

Questions:

(a) Why did Mr. Pollock choose to omit the remainder of the Board reference cited above which states "The costs associated with incremental load can be viewed as the cost of providing the standby distribution service."?

(b) Could the omitted statement be reasonably interpreted to support the approach taken by Energy+ in its Application? Do you agree with such an interpretation? If yes, why? If no, why not?

Responses:

(a) Mr. Pollock cited the relevant portion of the Board reference, which determines the cost of providing Supplementary distribution service. This is the step that Energy+ skipped in its CCOSS.

(b) No. Energy+ did not separately model the incremental load associated with Standby distribution service because it failed to consider the diversity of that load as required by the Board's directions.

7-EnergyPlus-21

Reference: **Mr. Pollock Evidence at page 29, lines 10 to 16.**

Board Directions on Cost Allocation Methodology for Electricity Distributors (EB-2005-0317)

Preamble: The evidence states the following:

"The Board should also direct Energy+, in consultation with TMMC to determine an allocation methodology for determining the cost of those primary poles, towers, and fixtures that are used to serve TMMC and other customers and file such methodology for Board approval within 90 days of the Board decision and order in this proceeding. To the extent that the specific cost of those poles serving TMMC can be directly assigned, there would be no reason to include TMMC's loads in allocating USoA 1830-4 costs."

The Board's direction on Direct Cost Allocation indicates at Section 5.2 that:

"Direct allocation is to be applied **if, and only if,** 100% of the use of a clearly identifiable and significant distribution facility can be tracked directly to a single rate classification."

Questions:

(a) Confirm Mr. Pollock follows the requirement in Section 5.2 of the Board's Directions on Cost Allocation in his approach to direct allocation?

(b) In light of the evidence that the poles, towers and fixtures are used to service multiple customer classes, confirm that Mr. Pollock does not attempt to directly allocate those costs to the Large User rate class?

Responses:

(a) Confirmed. The feeder costs (excluding poles, towers and fixtures) are used exclusively by TMMC and by no other Large Use customer or other rate classification.

(b) Confirmed. Mr. Pollock recognizes that poles, towers and fixtures supporting the directly assigned feeders also carry other feeders that serve multiple rate classifications. Mr. Pollock has allocated these costs to the Large Use rate classification.

7-EnergyPlus-22

Reference: **Mr. Pollock Evidence**
Energy+'s Make Whole Assertion at page 45, lines 12 to 19.

Preamble: The evidence states the following:

"Q. Is Energy+'s proposed Standby Distribution Service Rate Design necessary to keep it whole with respect to the costs associated with serving Peak Demand?"

"A. No. In this proceeding, the Board will set rates for each customer class using a Board approved CCOSS and projected billing determinants. By definition, the rates derived from a Board-approved CCOSS and billing determinants will fully recover the Energy+'s revenue requirement. There would be no trapped or unrecovered costs and, as a result. Energy+ would be made whole."

Questions:

(a) Are you aware of the evidence that Energy+ is forecasting multiple new LDG facilities to come online over the next five years? Can you update your response to address the potential impact the addition of new LDG facilities at different customers in Energy+'s service territory subsequent to rate setting.

(b) Explain how Energy+ would recover its revenue requirement without a standby distribution service rate if new LDG facilities were established in its service territory during the IRM term and reduced the billing determinants (peak demand) of other customers over that period.

Responses:

(a) Yes. Mr. Pollock cannot update his evidence to address the potential impact of additional LDG facilities because such a post-test year adjustment would be improper ratemaking, moreover, there is insufficient information upon which to assess potential impacts of potential new LDG facilities.

(b) Mr. Pollock is not suggesting that Energy+ should not have a Standby distribution service rate applicable to all LDG facilities. Please see TMMC's Response to SEC-TMMC-3a.

7-EnergyPlus-23

Standby Charges

Reference: **Mr. Pollock Evidence**
Standby Distribution Service Rate Design at page 12, lines 11 to 16.
Capacity Reservation at page 46, lines 18 to 22 and page 47, lines 1 to 2.

Preamble: Energy+ does not need to reserve incremental capacity in the Preston TS because there is no evidence that a simultaneous forced outage of both of TMMC's generator's would immediately increase TMMC's load by 9.2MW or that it would cause TMMC's peak demand to exceed what was TMMC's maximum load, prior to January 1, 2016, when its LDG facility commenced service.

Doesn't Energy+ also have to reserve 9.2MW of Capacity in the Preston TS to serve TMMC's Standby needs?

No, this statement assumes that both TMMC generators sustain simultaneous forced outages and that the impact of the simultaneous forced outage is a 9.2MW increase in TMMC's load, however, Energy+ has provided no evidence that a simultaneous forced outage would immediately increase TMMC's load by [redacted] MW or that it would cause TMMC's peak demand to exceed what was TMMC's maximum load prior to installing its LDG facility.

Further, as can be seen in Schedule JP-7, the maximum amount of Standby distribution service that has ever been taken by TMMC was [redacted] MW (line 22, column 3). This occurred during a rare simultaneous outage of both generators at 8am on Wednesday, November 8, 2017.

Questions:

(a) Describe the expectation that TMMC would have of Energy+ with respect to the availability to rely on the distribution system if there is a simultaneous outage of both generators while they were operating at full load. Would TMMC expect Energy+ to have [redacted] MW of capacity available at that time?

(b) Describe what other actions, if any, TMMC could take to curtail the requirement for demand on the Energy+ system in the event of a simultaneous outage of both generators. Please indicate whether the action taken would vary depending upon the time of day that the simultaneous outage occurs.

Responses:

(a) Based on past experience, TMMC does not expect that a simultaneous outage of both generators while they are operating at full load would increase TMMC's demand by **[**[redacted]**]** megawatts (MW). **Schedule JP-7** demonstrates that TMMC's maximum demand for Standby service was **[**[redacted] MW, which occurred in November 2017, despite the loss of both generators. Because TMMC's on-site generators provide some steam, the loss of these generators would affect other plant loads.

Because Energy+ has already designed the distribution system to accommodate TMMC's full load of over 35 MW, TMMC would be very concerned if Energy+ could not accommodate a maximum load of at least 27.6 MW during on-peak hours.

(b) Please see the response to (a). A further response can only be provided when Energy+ discloses the specific circumstances that would require TMMC to curtail its use of the Energy+ system during a simultaneous outage of both generators.

7-EnergyPlus-24

Standby Charges

References: **Mr. Pollock Evidence**
Capacity Reservation at page 48, line 1 to 8.

Response to IR-TMMC-3

Response to 7-Staff-78

Response to Interrogatories 7-SEC-39

Preamble: "Is Energy+'s proposal to periodically review and reset the Contracted Capacity Reserve a Reasonable Approach?

A. No. Energy+ has no incentive to ever reduce the arbitrarily selected Contract Demand value. Further, a customer would have no ability or leverage to negotiate a lower amount."

"Should the Board Place any weight on Energy+'s statement about resetting the contracted capacity reserve value?

A. No."

Question:

(a) On what factual basis does J. Pollock conclude that a Contracted Capacity amount based on <u>actual historical peak demand of the customer</u>, as outlined in Schedule 7 and interrogatory responses noted above, is considered arbitrary?

(b) If TMMC was able to reduce its actual demand during the historical period, wouldn't this give the customer direct control over the proposed Contract Demand value in a future year?

Responses:

(a) First, there was no standby rate in effect when that peak demand occurred. So, it is unknown whether the historical peaks shown in Schedule JP-7 would have occurred if a properly designed standby rate had been in effect. With a standby rate in effect, TMMC would have a stronger incentive to manage its loads so as to not exceed the standby contract capacity. Second, Schedule JP-7 demonstrates that the vast majority of times when TMMC required Standby service, peak demand was impacted by less than the rated capacity of one generator, except on two occasions.

(b) Other than establishing an initial Standby Contract Capacity, TMMC would not have complete control over its standby requirements. Further the Standby Contract Capacity would increase if TMMC were to use more standby capacity than specified. That amount could not be reset without Energy+'s approval.

7-EnergyPlus-25

Standby Charges

Reference: **Mr. Pollock Evidence**

How would the Standby Contract Demand be Determined at page 51, lines 15 to 23.

Response to IR-TMMC-3

Response to 7-Staff-78

Response to Interrogatories 7-SEC-39

Preamble: Q: How would the Standby Contract Demand be Determined

A: The customer would establish a Contract Demand under a written agreement between the customer and Energy+. Under no circumstances would the customer be allowed to designate more Standby Contract Demand than the nameplate rating of the customer's LDG. The customer should have the ability to periodically adjust the amount of Standby Contract Demand (up or down) as circumstances warrant (*i.e.,* addition/reduction in the amount of LDG capacity; operational changes). However, as discussed below, the Contract Demand could be adjusted if the customer actually uses more Standby distribution service.

Question:

(a) Explain the advantages and disadvantages of both the Energy+ proposal for determining Contract Demand (based on actual historical peak load in a prior year) and Mr. Pollock's proposal to determining Contract Demand (based on a percentage of nameplate capacity of the customer's LDG).

Response:

(a) The principal disadvantage of the Energy+ proposal for determining the Standby Contract Demand is that it predated the implementation of a specific standby rate. Further, under Energy+'s proposal, the Standby Contract Demand could only be reset at Energy+'s discretion.

The advantage of TMMC's proposed Standby Service rate is that TMMC would select the Standby Contract Demand based on a risk assessment and on its future expectations about the need for standby service, rather than on a one-time peak from a prior period when no applicable standby tariff was in effect.

7-EnergyPlus-26

Standby Charges

Reference: **Mr. Pollock Evidence**
How would the Daily Volumetric Rate Work at page 52, lines 7 to 9.

Preamble: The Daily Volumetric Rate would apply when the customer experiences an outage and as a result, establishes a higher monthly peak demand. The customer would have to notify Energy+ when an outage occurs and when the LDG has been fully restored.

Questions:

(a) How exactly would TMMC notify Energy+ when an outage occurs? What processes would be put in place for Energy+ to validate this claim?

(b) How exactly would TMMC notify Energy+ when the LDG has been fully restored? What processes would be put in place for Energy+ to validate this claim?

(c) Under what circumstances does TMMC currently notify Energy+ under (a) and (b)?

(d) Based on this proposal, and assuming the experience in 2016, 2017 and YTD 2018, how many times in each year would TMMC have had to notify Energy+ for each of the circumstances outlined in (a) and (b) above?

Responses:

(a)&(b) TMMC is amenable to negotiating the process for notifying Energy+ when and outage occurs and when generation has been fully restored. Because TMMC's gross and net loads are separately metered, it should be possible for Energy+ to validate when an outage has occurred and when the generation has been restored.

(c) Mr. Pollock is unaware of TMMC's obligations in this regard.

(d) It is unclear how many times TMMC would have had to notify Energy+ based on the past because there was no standby tariff in place. TMMC is willing to negotiate the protocols for notifying Energy+ when an outage occurs and when the LDG has been fully restored. Further, these protocols can differentiate between forced outages, which occur randomly without warning, and scheduled outages which can be planned in advance.

7-EnergyPlus-27

Standby Charges

Reference: **Mr. Pollock Evidence**

Standby Distribution Service Rate Design at page 53, lines 8 to 11.

Preamble: Is there any precedent for including both maximum and daily volumetric rates in designing a cost-based standby rate?

"Yes. The structure of my recommended standby rate closely parallels the rate designs approved by several state regulatory commissions in the United States."

Question:

(a) Are there any Ontario local distribution companies that have a rate structure that includes a maximum and daily volumetric rate as components to the standby rate? If yes, provide the names of the utilities and provide specific evidentiary references to the materials filed in those rate proceedings.

Response:

(a) Mr. Pollock cited rate designs approved in the United States as precedent for his proposal. He has not conducted any survey of Ontario local distribution companies rate structures to determine any similarities or differences with his proposed standby tariff.

7-EnergyPlus-28

Standby Charges

Reference: **Mr. Pollock Evidence**
Wrong Price Signals at page 48 to lines 9 to 16.

Preamble: "If the Standby Distribution Volumetric Rate is applied to a fixed contracted capacity reserve value, irrespective of the Customer's Actual Demand, does the Customer have any incentive to operate more efficiently.

A No. The Energy+ Standby distribution rate design sends exactly the wrong price signals. Requiring LDG customers to pay for a specified amount of capacity at a fixed rate provides no incentive to either defer unplanned outages or schedule maintenance outages from on-peak to off-peak hours."

Energy+ proposal as outlined in Schedule 7, IR-TMMC-3, 7-Staff-78, and 7-SEC-39 is to establish TMMC's Contract Demand based on TMMC's actual historical peak demand during a prior year. The question and answer cited above do not appear to contemplate this aspect of the Energy+ proposal.

Questions:

(a) Confirm that your understanding of the Energy+'s proposal is that it does not apply a "fixed contracted capacity reserve value, irrespective of Customer's Actual Demand", but rather Energy+ proposes to establish Contract demand based on TMMC's actual historical peak demand during a prior year. If not confirmed, please explain why – with specific reference to the evidence.

(b) Confirm that if Contract Demand is established based on TMMC's actual historical peak demand during a prior year that TMMC would continue to have an incentive to operate more efficiently, including if possible deferring outages and maintenance from on-peak to off-peak hours – since that effort would directly affect a future year's Contract Demand.

(c) Pease confirm whether TMMC also receives other price incentives arising from its LDG, outside of Energy+'s distribution rates (e.g. electricity commodity pricing, global adjustment charge, and other regulatory charges), as well as other operational benefits as a result of LDG, which may also incent deferring unplanned outages or schedule maintenance outages from on-peak to off-peak hours. Please describe each of these other financial and operational benefits.

Responses:

(a) Not confirmed. Energy+ used a fixed contracted capacity reserve value in determining the coincident peak and non-coincident peak allocation factors for the Large Use class in the CCOSS. This demonstrates how Energy+ is proposing to fix the standby contract demand and not use TMMC's actual historical peak demand during the prior year.

(b) Not confirmed. Mr. Pollock's understanding is that Energy+ is not proposing to automatically adjust TMMC's standby contract demand based on the actual historical peak demand during a prior year.

(c) TMMC is exposed to market energy rates as well as transmission charges and other adjustments. However, Energy+ does not charge for these services, and these services are not the subject of this rate case or costs that are recoverable in a standby distribution rate. Further, the commodity charges do not provide a price signal for TMMC to defer an outage or schedule a maintenance outage days, weeks, or months in advance.

7-EnergyPlus-29

Large User Class Rate Design

Reference: **Mr. Pollock Evidence**
Summary – Large Use Class Rate Design at page 11, lines 4 to 15.

Preamble: A properly designed Large Use class rate design should also recognize the different types of distribution costs incurred to serve this class. Thus, the Distribution Volumetric Rate should consist of three separate charges:

- A Bulk Distribution Volumetric Rate that recovers the allocated costs of the bulk (or shared) distribution assets;

- A Primary Substation Volumetric Rate that recovers the directly assigned feeder costs and an allocated share of the costs of poles, towers, and fixtures used to provide Primary Substation service; and

- A Primary Distribution Volumetric Rate that recovers the cost to provide Primary Distribution service.

Question:

(a) Provide a list of any and all local distribution companies in Ontario that have three separate distribution volumetric charges as part of their Large User class rate design.

Response:

(a) Mr. Pollock has not conducted a survey of the specific types of primary distribution service provided by other local distribution companies in Ontario. However, the three distribution volumetric charges comprise the unbundled costs to provide Primary Substation service and Primary Distribution service. The unbundled Bulk Distribution Volumetric rate would apply equally to both Primary Substation and Primary Distribution services. Thus, TMMC's proposed Large Use rate design consists of two separate rates. This two-part structure is essentially equivalent to a single Volumetric rate with a voltage or facilities discount.

Exhibit 8

8-EnergyPlus-30

Gross Load Billing Proposal

Reference: **Ms. Collis Affidavit**
Gross Load Billing Proposal at page 13, lines 266 to 272.

Responses to TMMC Questions #2, Sub-Questions VI.

Preamble: TMMC's position with respect to Energy+'s Gross Load Billing proposal states "Our position is that the Board should not approve Energy+'s Gross Load Billing Proposal because the Board has effectively put this issue "on hold" in response to concerns raised by parties about de-incentivizing distributed generation. In so doing, the Board has noted that "it may review this matter further on a generic basis and provide information in due course. This issue deserves a thorough examination that includes examination of how and why retail transmission charges are passed through to local distribution companies."

Questions:

(a) Confirm that as part of the installation of the LDG, a Measurement Canada-approved generation revenue meter was installed.

(b) Explain TMMC's understanding of the purpose of the approved generation revenue meter at the time of installation.

(c) Confirm whether TMMC understands that the computation of the Line Connection and Transformation Connection charges invoiced by the IESO specifically includes the kW of the TMMC generators. Confirm whether TMMC understands that these charges are not currently included in the RTSR rates billed to TMMC by Energy+, as Energy+ bills on the peak demand (which excludes the generation kW).

(d) As the RTSR Line Connection and Transformation Connection charges represent a flow-through cost to customers, explain TMMC's rationale as to the benefit to the community and/or why all other customers of Energy+ should be responsible for the RTSR Line Connection and Transformation Connection charges that specifically relate to the TMMC generation kW?

Responses:

(a) Confirmed.

(b) At the time of its installation TMMC understood that the purpose of the approved generation revenue meter was to bill TMMC for its share of the Debt Retirement Charge (DRC). Under Ontario regulations in place until recently, the DRC had to be paid on output from behind-the-meter generation installed after October 31, 1998.

(c) TMMC confirms the Line Connection and Transformation Connection charges invoiced by the IESO to Energy+ include amounts related to the kW of the TMMC generators.

TMMC does not, however, confirm that these charges from IESO are not currently included in the RTSR rates billed to TMMC by Energy+. IESO charges to Energy+ are determined by the peak gross demand of the Energy+ system on the IESO-controlled network. Energy+ charges to TMMC, in contrast, are based on TMMC's peak load on the Energy+ system. The timing of these two peaks is generally different (and will continue to differ even if TMMC's billing determinant is based on its gross load rather than its net load). Because timing differs and because of the impacts of the diversity between TMMC's load peak and Energy+'s system peak, the additional demand billed to Energy+ by Hydro One is likely to be less than the additional demand billed by Energy+ under a gross load billing proposal. Further, Energy+ RTSR rates differ from the rates applied by the IESO, which are based on Hydro One tariffs. Hence, the relationship between the additional amounts that are paid by Energy+ and the amounts currently actually paid by TMMC is unclear. Similarly, it is not clear whether the additional amounts paid by TMMC under Energy+'s gross load billing proposal would actually reflect any shortfall in amounts currently paid by TMMC.

TMMC has done some analysis of these issues and believes that additional amounts that would be collected by Energy+ under its gross load billing proposal would exceed any incremental amounts paid by Energy+ under Hydro One's current gross load billing approach. In its rate application, Energy+ has not provided a clear analysis of these issues and this is a significant deficiency in its application.

(d) As noted in our answer to (c), the "flow-through" nature of Energy+'s gross load billing proposal has not been established. Given the other reasons we have cited for deferring consideration of this issue (the OEB's desire to review this matter on a generic basis and concerns with de-incentivizing distributed generation), TMMC believes that Energy+'s gross load billing proposal should be rejected.