大成 DENTONS

Helen Newland
helen.newland@dentons.com
D +1 416 863 4471

Dentons Canada LLP
77 King Street West, Suite 400
Toronto-Dominion Centre
Toronto, ON, Canada M5K 0A1

dentons.com

April 12, 2019

VIA COURIER & RESS FILING

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th Floor, Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Commercial and Industrial Rate Design;
Board File No.: EB-2015-0043;
Toyota Motor Manufacturing Canada Inc.'s; February 21, 2019 Staff Report

We are writing on behalf of Toyota Motor Manufacturing Canada Inc. to file its comments on the Staff Report to the Board: Rate Design for Commercial and Industrial Customers to Support an Evolving Electricity Section. This submission has been filed through RESS and two hard copies are being couriered to the OEB today.

Yours very truly,

Dentons Canada LLP

original signed by Helen T. Newland

Helen T. Newland
HTN/ko
Encls.

cc: Melody Collis, TMMC
Stephanie Pollard, TMMC
Bill Fantin, TMMC
EB-2015-0043 Participants

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF a consultation regarding rate design for commercial and industrial electricity customers.

Toyota Motor Manufacturing Canada Inc's

Submission

April 12, 2019

1. This is the submission of Toyota Motor Manufacturing Canada Inc. ("**TMMC**") in respect of the report of Ontario Energy Board Staff ("**Staff**") entitled "Rate Design for Commercial and Industrial Electricity Customers", dated February 21, 2019 ("**Staff Report**"). This submission addresses Staff's proposal for a Capacity Reserve Charge ("**CRC Proposal**") applicable to customers with Load Displacement Generation ("**LDG**). TMMC is one such customer.

2. TMMC notes that it appears to be the only individual LDG customer who is participating directly in this proceeding.

3. TMMC has four material and significant concerns with the CRC Proposal:

   (a) The CRC Proposal is designed to preserve revenue for distribution utilities and is not based on the actual cost, to a distributor, of providing standby power to LDG customers. Indeed, Staff specifically tasked its consultant, Navigant Consulting, Inc., with quantifying the potential impact of LDG on system revenues under different scenarios. [1] In the result, the CRC Proposal is not grounded on fundamental rate-making principles of cost causality and avoidance of price discrimination.

   (b) The CRC Proposal is not clearly defined or articulated, lacks supporting cost analysis and does not recognize the significant imbalance in bargaining power between distributors and their customers.

   (c) The CRC Proposal provides limited or no incentive for LDG customers to manage their facilities in a manner that reduces system costs of providing them with standby power and, in particular, that minimizes their demands on the distribution system during peak periods.

   (d) The CRC Proposal does not include information on how rates would be implemented in practice and, in particular, how they would be integrated with the general cost allocation process used to set base distribution tariffs.

   These concerns are discussed in more detail in the sections below.

[1] Staff Report, Appendix B, p. 2.

Lack of Consideration of Cost Causality

4. The Staff Report contains no analysis of the costs for a distribution utility of providing standby back-up power. Rather, it simply analyzes the revenue implications of the introduction of LDG by a portion of a distributor's customer base and then designs rates in order to recover apparent revenue shortfalls.

5. The actual costs to the utility of providing standby power will be influenced by:

   (a) the diversity factor associated with demands placed on the system for standby service by individual customers with LDG; and

   (b) the proportion of the distribution system that is designed to meet general system peaks versus the proportion of the system designed to meet specific customers' individual demand peaks; a proper cost-based analysis would recognize that bulk capacity on the system that is freed-up by the installation of LDG is generally available to serve other customer loads.

6. Cost-based rates for providing standby power have been the focus of extensive deliberations in other jurisdictions, most notably in the U.S. However, the Staff Report does not refer this experience in its findings and analysis. We further note that TMMC commissioned a report by electricity cost allocation and rate design expert, Jeffry Pollock (the "**Pollock Report**"), that sets out a cost-based approach for designing stand-by tariffs. This was provided in evidence in Proceeding EB-2018-0028 convened to consider and decide Energy+'s application for 2019 distribution rates. A copy of the Pollock Report (redacted) is included as Attachment A to this submission for ease of reference. See, in particular, pages 25-34 and pages 54-72.

Use of Nameplate Capacity

7. The Staff Report assumes that nameplate capacity should be the basis of any standby tariff. The Pollock Report, however, demonstrates that the requirement for standby power may not be equal to the nameplate capacity of installed facilities. The loss of a generator does not automatically result in a customer requiring an incremental amount of standby power service that is equal to the capacity rating of the LDG. The additional loads placed on the system are often less because LDG may be integral to the production process. Hence, loads may be reduced in parallel with LDG outages. Further, outages may occur during a plant-wide turndown, in which case no

additional loads may be placed on the system during an outage, relative to those that would already have been observed in the associated billing period.

The Role of Diversity and of Local versus Bulk Facilities

8. The Staff Report ignores the importance of customer diversity in determining actual capacity requirements for the distributor. It also ignores the difference between those assets specific to a given customer, and those assets that serve many customers in parallel but perhaps at different times (i.e. bulk facilities).

9. Thus, using the demand charge in the CRC formula is problematic because it assumes that a distributor must reserve capacity at all times on all of the distribution facilities used to serve a specific customer. That statement would be correct if there were no demand diversity on the system. (Demand diversity means that individual customers experience peak electrical demands at different times.) Because of diversity, a utility can, in practice, install smaller size transformers and distribution feeders than would be implied by simply adding up all customers' non-coincident peak loads. For example, a 25 kVA transformer can often reliably meet the needs of three separate 10 kW loads. If there were zero diversity, the transformer would have to be sized at 30 kVA. Diversity plays a larger and larger role in the cost allocation process as one moves away from the specific assets serving an individual customer (i.e. 'upstream' within the distribution system).

10. In the design of standby tariffs, it is appropriate to fully recover the costs of any local facilities that are used to serve a given customer, in a monthly fixed charge. In contrast, the cost of upstream (or shared) facilities should only be recovered in proportion to the extent to which facilities are actually used; for example, through a daily demand charge. This is standard practice in many jurisdictions and provides incentives for users to minimize their use of the shared distribution system, thereby freeing up system capacity for other uses. The exact delineation between local and shared facilities may not, in practice, always be clear; however, it is better to make reasonable assumptions for this delineation than to completely ignore the issue of shared versus local costs in the rate design process. Standard assumptions on the split between shared and local costs could be developed for typical circumstances, as appropriate, given that it may be too costly to do detailed analysis in each instance for smaller LDG facilities or at smaller LDCs.

11. Staff's CRC Proposal simply ignores the considerable precedent in other jurisdictions for distinguishing between shared and local costs. For example, as noted in TMMC Response to Interrogatories (Round #2) – VECC 15.0 (in Proceeding EB-2018-0028), the New York State

Public Service Commission has defined standard assumptions for the local versus shared split for the secondary, primary, substation and transmission facilities assigned to each of secondary, primary and over 138 kV customers. These assumptions may not be perfect in every instance but having standard assumptions for rate design purposes is preferable to completely ignoring (i) differences in the role and cost of the facilities that provide service; and (ii) the implications of diversity on the cost of providing standby-distribution service.

12. The role of diversity is already recognized in setting base distribution tariffs in Ontario and should be similarly recognized in setting standby tariffs. Without diversity, applying cost-causation principles would require that distribution costs be allocated in proportion to each customer's individual peak demand rather than to each class's peak demand. This is not done and, if it were done, would allocate more costs to residential and small commercial customers, who have higher diversity factor than larger users. The reality is that a distribution utility sizes its equipment to meet the "diversified" demands of its customers. Because of demand diversity, one cannot assume that an unplanned generator outage will always occur coincident with the distribution system peak. The CRC Proposal completely ignores the important role that diversity plays in determining the actual costs of serving a given load.

Evolution of Tariffs over Time

13. Because the Staff Report provides no analysis of the costs of providing standby service, it provides no mechanism or approach for updating the results of the cost allocation process over time. The Staff Report suggests that cost allocation studies establish a fixed obligation to pay over the (30-year or longer) life of the distribution assets. This is fundamentally wrong. Class cost-of-service studies determine the proper allocation of costs and cost-based rate designs based on a single test year. A test year is only a "snapshot" in time. After the test year, a utility's revenues and costs will change and loads will also change. The loads of specific customer classes may grow at different rates. This uneven load growth will result in a different allocation of costs in a subsequent test year. <u>This is not cost shifting; it is simply recognizing the dynamic interactions between sales, revenues, and costs.</u>

Lack of Clarity and of Appropriate Incentives for Customers

14. The Staff Report initially suggests that customers would have the option of taking different types of service (Emergency Backup Service, Maintenance Service, or Basic Connection). However, it later states that the only type of CRC available to GS>= 50kW customers would be for full Emergency Backup Service ("**EBS"**).

15. The discussion of Maintenance Service ("**MS**") indicates it would be available on a negotiated basis, with the rate calculated using a "maintenance factor" such as between 25% and 50%. MS would provide access to the system only at off-peak times "at the distributor's discretion". Further, MS would be combined with some form of exit payment since the customer is deemed to be "abandoning" load. (p. 45)

16. Our concerns with the Staff Report's discussion of MS are as follows:

    (a) there is significant ambiguity in the Staff Report as to the actual availability of MS;

    (b) no analysis or support is provided for the suggested range for a maintenance factor of between 25% and 50%; the range seems high, particularly given that it will be implemented in conjunction with an exit payment; and

    (c) providing that rates be implemented on a negotiated basis is contrary to standard rate-making practices in the province and will result in significant fairness issues given the imbalance in bargaining power that exists between any individual customer and its local monopoly utility provider.

17. A very disturbing element of the Staff Report is the notion that a customer who installs LDG and permanently removes load from the grid but maintains a connection to the grid (i.e., partial bypass) could be subject to paying a "bypass compensation" charge (pp 45-46).

18. TMMC has significant concerns with the idea that non-cost-based CRCs or, worse, exit payments will be applied to customers who permanently reduce load as a result of installing LDG. This would raise concerns about price discrimination between different customers who permanently reduce load but for different reasons. Reductions in a customer's load, for example, could occur because of reductions in its business operations or because of installation of energy efficiency equipment, instead of as a result of the installation of LDG. It is discriminatory to charge an exit fee to one customer (i.e. those who install LDG) but not to charge similar fees to other customers that may have similar reductions in load but for other reasons.

19. An appropriate rate must also provide incentives to LDG customers to minimize the duration of outages and to schedule planned outages for off-peak periods. The proposed CRC provides none of these incentives.

20. The incentives provided to customers are very important in the design of rates, in particular, for 'dispatchable' LDG facilities, such as those based on natural gas, that can run on an around-the-

clock basis if desired. They are much less important or not relevant for intermittent generation such as solar rooftop facilities, where the customer does not have control over the profile of generation output. Accordingly, it may not be appropriate to introduce a standard rate design that covers both types of facilities. The OEB report recommends different "capacity factors" for different types of technologies but does not contemplate any other differences in the rate design applied. This is short-sighted and points to the inadequacy of the Board's analysis.

Lack of Detail on Integration with Existing Cost Allocation Processes

21. The Staff Report leaves a number of important questions unanswered about the mechanics of the process of implementing the proposed standby rate. For example, the Staff Report does not address how implementation of the new rate will influence the cost allocation process for setting base tariffs for a specific customer class. Specifically, will the base tariff be taken just as a given in the rate setting process (in other words, will it be just a fixed initial input) or will it adjusted in parallel to:

(a) reflect expected revenues from the proposed standby tariff; and/or

(b) reflect changes in the demand allocators for that customer class (and hence class-allocated costs) because of the provision of standby service?

22. In other words, the Staff Report is silent on the impact of the new standby tariff on processes of cost allocation for base tariffs. The class coincident peak demand will be reduced if a significant portion of customers in a class install LDG. We would normally expect that this would result in a reduction in class allocated costs, as system capacity is freed-up for use by other LDC users. However, the Staff Report does not consider these detailed issues of LDC rate design. Hence, the analysis is superficial and leaves important questions unanswered. As noted earlier in this letter, these questions will become increasingly important over time as demand and usage patterns shift at the utility.

Summary

23. TMMC agrees that it is reasonable to charge for the provision of standby service provided the charge is commensurate with the cost of providing the service. The CRC should not simply be a mechanism for recovering a distributor's "lost revenue".

24. An appropriate rate must also provide incentives to LDG customers to minimize the duration of outages and to schedule planned outages for off-peak periods. The proposed CRC provides none of these incentives.

25. TMMC would welcome the opportunity to provide additional input on the standby issue in this proceeding. We would also make the following requests:

(a) that Staff provide information on the modeling that was done to support Staff's CRC Proposal; calculations underlying the various methodologies have not been provided and remain unclear; and

(b) that the Staff provide an assessment of how its proposed approach aligns with the methodologies applied in other jurisdictions; in particular, the Staff should examine precedents in the U.S, where there has been significant deliberation regarding appropriate methodologies for applying standby tariffs; this reflects government and, in particular, FERC policies that seek to establish a level playing field for different sources of generation.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 12TH DAY OF APRIL 2019.

DENTONS CANADA LLP

Per:

original signed by Helen T. Newland

Helen T. Newland

Attachment A

EB-2018-0028

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.

REDACTED VERSION

Updated Written Evidence

of

Jeffry Pollock
(J. Pollock Incorporated)

On behalf of

Toyota Motor Manufacturing Canada Inc.

February 15, 2019

J. POLLOCK
INCORPORATED

Table of Contents

LIST OF SCHEDULES 3
GLOSSARY OF ACRONYMS AND DEFINED TERMS 4
UPDATED WRITTEN EVIDENCE OF JEFFRY POLLOCK 5
1. INTRODUCTION AND SUMMARY 5
2. REVISED CLASS COST-OF-SERVICE STUDY 11
3. SUPPLEMENTARY DISTRIBUTION SERVICE RATE DESIGN 21
4. STANDBY DISTRIBUTION SERVICE RATE DESIGN 25
5. CONCLUSION 33
APPENDIX C 35
APPENDIX D-1 44
APPENDIX D-2 54
APPENDIX E 64
FORM A 73

LIST OF SCHEDULES

Schedule	Description
JP-11	2019 Cost Allocation Model: Two Large Use Classes/Direct Assignment
JP-12	4NCP and 12CP Allocation Factors With and Without TMMC
JP-13	TMMC Recommended Supplementary Distribution Service Rate Design
JP-14	TMMC Recommended Standby Distribution Service Rate Design
JP-15	Recommended Standby Distribution Service Rate Design Applicable to the GS 50 – 999 kW Customer Class
JP-16	Revenues from TMMC Recommended Standby Distribution Service Rate

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Term	Definition
4NCP	Four Non-Coincident Peak
12CP	Twelve Coincident Peak
Application	Energy+'s 2019 Cost of Service Application
CCOSS	Class Cost-of-Service Study
Energy+	Energy+ Inc.
Hydro One	Hydro One Networks Inc.
kW	Kilowatt
kV	Kilovolt
LDG	Load Displacement Generation
M24 and M30 Feeders	Energy+'s 27.6 kV Overhead Conductors connecting TMMC to Hydro One's Preston TS that are used exclusively to provide distribution service to TMMC
O&M	Operation and Maintenance
OEB or Board	Ontario Energy Board
Preston TS	Preston Transformer Substation
Settlement Proposal	Partial Settlement Proposal and related supporting documentation in respect of Energy+'s 2019 Cost of Service Application, filed with the Board on December 12, 2018
TCQ	Technical Conference Question
TMMC	Toyota Motor Manufacturing Canada Inc.

UPDATED WRITTEN EVIDENCE OF JEFFRY POLLOCK

1. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

Q. ARE YOU THE SAME JEFFRY POLLOCK WHO SUBMITTED EVIDENCE IN THIS PROCEEDING DATED SEPTEMBER 27, 2018, ADDRESSING ENERGY+'S CLASS COST-OF-SERVICE STUDY, LARGE USE CLASS RATE DESIGN AND STANDBY DISTRIBUTION SERVICE RATE DESIGN?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR UPDATED WRITTEN EVIDENCE?

A. The purpose of this updated written evidence is to present the results of a new class cost-of-service study (CCOSS) based on a separate TMMC Large Use class and the direct assignment to that class of the specific costs to serve TMMC. I refer to this new study as the "Two Large Use Classes/Direct Assignment" study. Based on the Two Large Use Classes/Direct Assignment study, I also recommend TMMC-specific rate designs for both Supplementary (*i.e.,* regular) Distribution service and Standby Distribution service.

In addition, for reference only and to provide both continuity and completeness, I have updated the CCOSS and the Supplementary and Standby rate designs presented in **Schedules JP-5, JP-6, JP-8,** and **JP-9** of my original written evidence filed on September 27, 2018. I refer to the originally filed CCOSS as the "One Large Use Class/Partial Direct Assignment" study. These updated schedules are included in **Appendix C**.

To be clear, although revised **Schedules JP-5, JP-6, JP-8 and JP-9** are included in **Appendix C** of this updated evidence, new **Schedules JP-11, JP-12, JP-13, JP-14 and JP-16**, which are based on the Two Large Use Classes/Direct Assignment CCOSS, reflect the cost allocation and rate designs that I am now recommending.

Q. WHAT IS THE STATUS OF YOUR ORIGINAL EVIDENCE DATED SEPTEMBER 27, 2018?

A. My original evidence remains on the record of this proceeding and, together with this updated evidence and all of my responses to interrogatories and Technical Conference undertakings, comprises the totality of my written evidence in this proceeding to date. However, as described above, the One Large Use Class/Partial Direct Assignment study in my original evidence has been replaced with the Two Large Use Classes/Direct Assignment CCOSS included in this updated evidence. The balance of my original evidence and, in particular, my detailed critiques of Energy+'s CCOSS and proposed standby rate design, is not amended or replaced by this updated evidence.

Q. WHY DID YOU DEVELOP A NEW CLASS COST-OF-SERVICE STUDY?

A. Since submitting my original evidence, three new circumstances have arisen. First, in an interrogatory dated October 11, 2018, the OEB Staff asked TMMC to provide an alternative cost allocation model that treats TMMC and the other Large Use customer as separate customer classes (*i.e.,* Two Large Use classes). TMMC filed its response on October 29, 2018.[1] Although, my original evidence was based on a One Large Use Class/Partial Direct Assignment study, my recommended rate design for the single class included separate volumetric rates for TMMC and the other Large Use customer. Separate rates were designed in order to specifically recognize that TMMC receives a different (and less costly) type of distribution service (*i.e.,* Primary Substation service) than the other Large Use customer (*i.e.,* which receives Primary Distribution service). This original proposed rate design was, in effect, a proxy for a two Large Use class structure. After further consideration, I now believe that the One Large Use Class/Partial Direct Assignment study and the rate designs derived from that study would not be consistent with the Board's current practice and policy.

Second, since the time of my original evidence and in response to a written interrogatory from TMMC, Energy+ filed a CCOSS that reflects the settlement of the revenue requirement elements of its Application, a separate TMMC customer class, and direct assignment of all of the costs of providing distribution service to TMMC (*i.e.,* the "Direct Assignment Study").[2] The Direct Assignment Study identifies the cost of the facilities that are used *exclusively* to serve TMMC, namely: two 27.6 kilovolt (kV) feeders and associated facilities such as load-break switches, lightning arrestors and clamps, bolts and bracket connectors (together, the "M24 and M30 Feeders"); four upgraded meters; and TMMC's capital contribution. It also includes an analysis of the costs of the primary poles, towers and fixtures (booked to USoA 1830-4) that support the dedicated M24 and M30 Feeders but also serve other loads.[3] Finally, the Direct

[1] TMMC Response to OEB Staff Interrogatory 1(b).

[2] Energy+ Response to TMMC TCQ IR-2(c).

[3] *Id.*

Assignment Study identifies operation and maintenance (O&M) activities and associated expenses that could be directly allocated to TMMC.

Third, during the Technical Conference held on January 23, 2019, I learned that Energy+ does not own any high voltage (>50 kV) Bulk distribution facilities at the Preston Transformer Substation (Preston TS), which is owned by Hydro-One Networks Inc. (Hydro One). This fact is notable because the M24 and M30 Feeders, which are used exclusively to serve TMMC, are directly connected to the Preston TS. If the Preston TS were to sustain an outage, TMMC would be without power.[4]

In light of all of the above, I developed a new CCOSS with two Large Use classes that, *with the sole exception of the "shared" poles*, directly assigns all other distribution-related costs to the TMMC Large Use Class (*i.e.,* Two Large Use Classes/Direct Assignment). This approach follows Board policy, which mandates direct allocation if 100% of the use of a clearly identifiable and significant distribution facility can be tracked directly to a single rate classification.[5]

To be clear, although Energy+'s Direct Assignment Study assigned 100% of the cost of the poles that support TMMC's dedicated M24 and M30 Feeders to the TMMC Large Use Class, the Two Large Use Classes/Direct Assignment study that I am proposing recognizes that the Energy+ poles supporting the M24 and M30 Feeders are shared assets. Accordingly, as *per* Board policy, I have allocated the costs of Primary Poles, Towers and Fixtures recorded in USoA 1830-4 across all rate classes, including the TMMC Large Use rate class. The results of the Two Large Use

[4] Technical Conference Transcript at 37-38 (Jan. 23, 2019).

[5] EB-2005-0317, Cost Allocation Review, *Board Directions on Cost Allocation Methodology for Electricity Distributors* at 31 (Sept. 29, 2006).

Classes/Direct Assignment CCOSS are provided in **Schedule JP-11** to this updated evidence.

Q. WHY IS IT APPROPRIATE TO ESTABLISH A SEPARATE CUSTOMER CLASS FOR TMMC?

A. Separate customer classes are required when the per-unit customer or demand-related costs are sufficiently different between identifiable groups of customers to justify different rates.[6] That is the case here because there are four key differences between how TMMC and the other Large Use customer receive distribution service and the characteristics of these services. These differences result in substantial differences in the costs of providing distribution service.

First and importantly, TMMC operates a load displacement generation (LDG) facility. The other Large Use customer does not have any LDG facilities. The presence of LDG means that TMMC would have different load characteristics than the other Large Use customer, which does not have LDG.

Second, TMMC's load is in excess of 20 MW, while the other Large Use customer's load is only about 5 MW. Size creates scale economies; that is, the larger the customer, the lower the fixed costs per customer. Recognizing TMMC's larger size is also consistent with how the OEB uses size to define the other general service customer classes. Further, the Two Large Use Classes/Direct Assignment study shows that the per-unit customer-related cost to serve TMMC is substantially below

[6] EB-2007-0031, Staff Discussion Paper, *Rate Design for Recovery of Electricity Distribution Costs* at 22 (Mar. 31, 2008 Revised Jun. 6, 2008).

the corresponding per-unit customer-related cost to serve the other Large Use class customer.

Third, as discussed in my original written evidence and documented in **Schedule JP-2**, TMMC receives Primary Substation service whereas the other Large Use customer receives Primary Distribution service. These are two *different* types of service. Primary Substation service is provided when the customer is served from dedicated feeder lines that are directly connected to a transformer substation. The dedicated M24 and M30 Feeders that serve TMMC are directly connected to Preston TS. This is TMMC's only electrical connection to the Energy+ distribution system. This is in contrast to the other Large Use customer, which receives Primary Distribution service using Energy+'s integrated primary distribution network. Hence, there are no Energy+ assets that are used exclusively to serve this customer. Primary Substation service is less costly than Primary Distribution service.

Fourth, with the sole exception of primary poles, all of the distribution facilities that serve TMMC are exclusively used by TMMC, and no other Energy+ customers can be served from these facilities. This means that all distribution facilities used to serve TMMC, other than poles, can be directly assigned to TMMC.

2. REVISED CLASS COST-OF-SERVICE STUDY

Q. DO YOU AGREE WITH ENERGY+'S CLASS COST-OF-SERVICE STUDY FILED IN ITS APPLICATION, AS UPDATED IN THE SETTLEMENT PROPOSAL?

A. No. The cost allocation methodologies used by Energy+ in both its Application and the Settlement Proposal (*i.e.,* "Settlement CCOSS") are not consistent with the principles of cost causation for the reasons explained in my original written evidence.[7] For ease of reference, I have summarized my critique of Energy+'s CCOSS in **Appendix D-1**. The same criticisms equally apply to the Settlement CCOSS. Accordingly, for purposes of setting rates in this proceeding, the Board should not accept the Settlement CCOSS and should accept my Two Large Use Classes/Direct Assignment study as presented in **Schedule JP-11**.

Q. WHAT CHANGES DID YOU INITIALLY MAKE TO ENERGY+'S COST ALLOCATION METHODOLOGIES?

A. The One Large Use Class/Partial Direct Assignment study presented in **Schedule JP-5** of my original written evidence included the following changes to the cost allocation methodologies used by Energy+:

- I removed Energy+'s LDG adjustments to the Large Use class demands that are used to develop the 12CP, 4NCP, and 12NCP demands that are used to allocate demand-related costs in the CCOSS.
- The direct and indirect costs of the M24 and M30 (dedicated) Feeders were directly assigned to the Large Use class.

These changes are discussed in **Appendix D-1**.

[7] The Settlement CCOSS was filed by Energy+ in its Settlement Proposal dated Dec. 12, 2018, file name: "2019 EnergyPlus Cost_Allocation_Model – Settlement.xlsm."

Q. WHAT FURTHER CHANGES HAVE YOU MADE TO SCHEDULE JP-5 THAT ARE NOW REFLECTED IN SCHEDULE JP-11?

A. First, **Schedule JP-11** corrects several inadvertent errors and incorporates more up-to-date information. Second, as previously stated, **Schedule JP-11** is based on two Large Use classes in contrast to the Settlement CCOSS and my One Large Use Class/Partial Direct Assignment study (**Schedule JP-5)**, which are both based on one Large Use class. Third, in **Schedule JP-11**, I directly assigned all distribution costs (with the sole exception of the primary poles) to TMMC using Energy+'s Direct Assignment Study, whereas only the costs of the M24 and M30 Feeders were directly allocated in **Schedule JP-5**. Finally, unlike in **Schedule JP-5**, I did not allocate any >50 kV (Bulk) distribution costs to TMMC and to the other Large Use customer in **Schedule JP-11**.[8]

Q. PLEASE DESCRIBE THE SPECIFIC CHANGES IN SCHEDULE JP-11.

A. There are two specific changes. The first change is a correction to the demands and associated allocation factors due to the inadvertent removal of the wholesale market participants' adjustments to the GS >50 kilowatt (kW) classes. The second change reflects the use of more up-to-date data, namely the revenue requirement settlement reached by Energy+ and intervenors and filed with the Board on December 12, 2018 (Settlement Proposal).

[8] In **Schedule JP-5** as updated in **Appendix C** of this evidence, the >50 kV distribution costs were allocated to all retail customer classes, including the Large Use class.

Q. DID YOU MAKE THE SAME TWO CHANGES TO SCHEDULE JP-5 AS UPDATED IN APPENDIX C?

A. Yes.

Q. YOU USED ENERGY+'S DIRECT ASSIGNMENT STUDY TO DIRECTLY ASSIGN DISTRIBUTION COSTS TO THE TMMC CLASS IN SCHEDULE JP-11. CAN YOU DESCRIBE THAT STUDY?

A. Yes. Energy+'s Direct Assignment Study identified and quantified the costs of the Energy+ facilities used to provide distribution service to TMMC. These facilities include:

- The M24 and M30 Feeders that are used exclusively to serve TMMC;
- The primary poles, towers and fixtures recorded in USoA 1830-4 that support those feeders; and
- The metering equipment that is similarly dedicated to TMMC.

In addition, the Direct Assignment Study identified the specific capital contributions made by TMMC to the original capital cost of the dedicated distribution assets that Energy+ uses to deliver electricity to TMMC.

Q. DID ENERGY+ ALSO QUANTIFY DIRECTLY ASSIGNED EXPENSES?

A. Yes. Energy+ also quantified the O&M expenses incurred by Energy+ solely for the account of TMMC. These directly assigned O&M expenses include:

- Maintenance of the directly assigned infrastructure comprising direct labor costs, general plant (use of Energy+ vehicles) and tree trimming; and
- Control room services incurred to coordinate maintenance schedules and outages of TMMC's LDG facility.

Q. WOULD YOU CHARACTERIZE ENERGY+'S DIRECT ASSIGNMENT STUDY AS DEFINITIVE?

A. Yes. Although, Energy+ acknowledged that the Direct Assignment Study did not include Energy+'s investments in certain equipment (*i.e.,* guys, anchors, and grounding/neutral conductors) that support the direct assigned overhead feeders.[9] There is no indication that these omissions would materially change the amount of costs directly assigned to TMMC. Moreover, as discussed later in this evidence, the rate design that I am now recommending for TMMC would establish a target revenue requirement based on a 1.15 revenue-to-cost ratio. This will provide a more than ample cushion above a purely cost-based rate to offset any additional incidental costs that the Direct Assignment Study does not account for. For these reasons, the Board should accept the results of Energy+'s Direct Assignment Study for the purpose of setting rates in this proceeding.

Q. WHAT ARE THE RESULTS OF ENERGY+'S DIRECT ASSIGNMENT STUDY?

A. The results of Energy+'s Direct Assignment Study are summarized in Table 8.

Table 8
Adjustments for TMMC Direct Assignment Study[10]

Description	Fixed Assets	Capital Contrib.	Accumulated Amortization	O&M Expense	Depreciation Expense
Dedicated Feeders	[redacted]	$-	[redacted]	$-	[redacted]
Poles	[redacted]	$-	[redacted]	$-	[redacted]
Dedicated Metering Equipment	[redacted]	$-	[redacted]	$-	[redacted]
TMMC Capital Contribution	$-	[redacted]	[redacted]	$-	[redacted]

[9] Energy+ Response to TCQ TMMC IR-1(c) and 1(d). In Undertaking JTC1.5 Energy+ stated that it had no investment in either current or potential transformers associated with TMMC's metering equipment.

[10] Energy+ Response to TCQ TMMC IR-2(c).

Table 8
Adjustments for TMMC Direct Assignment Study[10]

Description	Fixed Assets	Capital Contrib.	Accumulated Amortization	O&M Expense	Depreciation Expense
O&M on Dedicated Feeders	$-	$-	$-	[redacted]	$-
Total	[redacted]				

Q. WHAT DO THE COSTS ASSOCIATED WITH THE POLES IN TABLE 8 REPRESENT?

A The costs of the poles shown in Table 8 represent the total fixed assets, accumulated depreciation and depreciation expense associated with all primary poles that support the dedicated M24 and M30 Feeders.

Q. ARE YOU AWARE THAT THERE ARE OTHER ENERGY+ DISTRIBUTION FEEDERS THAT USE THE SAME POLES AS THE DEDICATED M24 AND M30 FEEDERS?

A. Yes. Energy+ has advised that there are three other distribution feeders (M23, M27, and M29) that are supported, in part, by the same primary poles that support the dedicated M24 and M30 Feeders. These other feeders collectively serve more load than TMMC's load.[11] Hence, from TMMC's perspective, the primary poles are clearly "shared" (as opposed to "local") facilities because they are not used exclusively to serve TMMC. As discussed later in my evidence, the primary poles are the only shared distribution facilities used to serve TMMC.

[11] Energy+ Response to TCQ TMMC IR-1(e).

Q. HOW ARE SHARED DISTRIBUTION FACILITIES DIFFERENT FROM LOCAL DISTRIBUTION FACILITIES?

A Shared distribution facilities are generally used by all customers, whereas local distribution facilities serve only a specific customer or customer groups. To use an analogy, shared facilities are the highway and byway, while local facilities are the side-street and driveway.

Q. WERE ANY OTHER CHANGES MADE AS A RESULT OF USING ENERGY+'S DIRECT ASSIGNMENT STUDY?

A. Yes. As discussed previously, for the Two Large Use Class/Direct Assignment CCOSS in **Schedule JP-11**, I directly assigned the costs of the facilities that are exclusively used by TMMC (*i.e.,* the M24 and M30 Feeders, meters, capital contribution). Because all costs are being directly assigned to TMMC, with the exception of the primary poles, I also removed TMMC's loads from the four non-coincident peak (4NCP) demand allocation factors that are used to allocate primary distribution costs. This adjustment is shown in **Schedule JP-12**. Removing TMMC's loads is consistent with OEB policy. Specifically:

> When direct allocation is used, the distributor should consider whether it needs to adjust the appropriate allocation factors so that the rate classification to which costs for a specific function are directly allocated is not allocated further costs related to that function, except where there are joint costs that apply to the customer classification. For example, if a customer classification has all its assets and O&M costs directly allocated to the classification, then the load data used to allocate

"common" assets and O&M costs should exclude the load data associated with this customer classification.[12]

Q. DID YOU USE THE SAME ALLOCATION FACTORS AS ENERGY+ IN ALLOCATING THE COSTS ASSOCIATED WITH THE PRIMARY POLES?

A. No. In allocating the primary poles, which are booked to USoA 1830-4, I removed Energy+'s LDG facility adjustment. This is because there is no evidence that TMMC would always use Standby Distribution service that is 100% coincident with TMMC's 4NCP demands. The reasons for removing Energy+'s LDG adjustment are further discussed in **Appendix D-1**.

Q. HAVE YOU CHANGED YOUR RECOMMENDATION ON ALLOCATING UNDERGROUND FACILITIES IN SCHEDULE JP-11?

A. No. As was the case with my One Large Use Class/Partial Direct Assignment study (**Schedule JP-5)**, I did not allocate any underground investment (*i.e.,* conduit and conductors) and related expenses (including overhead costs) to TMMC. TMMC is served entirely from an overhead "radial" distribution system, and Energy+ does not use any underground equipment to serve TMMC. Further, because the radial system is not electrically connected to any underground facilities, TMMC cannot possibly benefit from any system integration function that these facilities provide, if any. Accordingly, allocating zero underground costs to TMMC is consistent with cost-causation principles.

[12] EB-2005-0317, Cost Allocation Review, *Board Directions on Cost Allocation Methodology for Electricity Distributors* at 32 (Sept. 29, 2006).

Q. IS COST CAUSATION AN ACCEPTED PRACTICE?

A. Yes. The Board has stated:

> The primary criterion in developing the cost allocation methodology is to follow sound cost causality. Secondary considerations include the availability and reliability of the data to support the exercise, as well as concerns of materiality, practicability and consistency.
>
> The key objective of the cost allocation is to allocate costs among classifications appropriately reflecting cost causality. This objective is furthered by separating distribution assets into bulk, primary and secondary functions.[13]

Q. WHAT DO THE RESULTS IN SCHEDULE JP-11 DEMONSTRATE?

A. Table 9 below shows the revenue requirement and the revenue-to-cost ratios at present rates under the Two Large Use Classes/Direct Assignment study. The corresponding information from Energy+'s Settlement CCOSS is also shown for comparison purposes.

Table 9
Summary of TMMC's Recommended and Energy+'s Settlement CCOSS Results[14]

Customer Class	Revenue Requirement ($000)		Revenue-To-Cost Ratio at Current Rates	
	TMMC	Energy+	TMMC	Energy+
Residential	$22,785.6	$22,646.9	84.9%	85.4%
GS < 50 kW	$4,166.6	$4,104.4	107.1%	108.7%
GS: 50 – 999 kW	$5,839.7	$5,633.4	135.4%	140.3%
GS: 1,000 – 4,999 kW	$2,118.7	$2,012.7	108.0%	113.5%
Large Use	N/A	$1,108.3	N/A	100.7%
Large Use 1	$206.1	N/A	133.8%	N/A
TMMC (Large Use 2)	$391.9	N/A	212.2%	N/A

[13] *Id.* at 3 and 35.

[14] TMMC **Schedule JP-11**; Energy+ Settlement CCOSS, Rows 40 and 75.

Table 9
Summary of TMMC's Recommended and Energy+'s Settlement CCOSS Results[14]

Customer Class	Revenue Requirement ($000)		Revenue-To-Cost Ratio at Current Rates	
	TMMC	Energy+	TMMC	Energy+
Street Light	$493.1	$494.7	151.2%	150.8%
Sentinel	$23.2	$23.4	70.1%	69.6%
Unmetered Load	$78.1	$78.3	90.0%	89.7%
Hydro One 1 CND	$43.5	$43.4	120.7%	120.9%
Waterloo No. CND	$157.9	$157.9	144.9%	144.8%
Hydro One BCP	$29.5	$30.5	401.3%	401.4%
Brantford Power	$12.9	$12.9	44.6%	44.6%
Hydro One 2 BCP	$3.0	$3.0	167.9%	167.9%

Table 9 demonstrates that TMMC's revenue-to-cost ratio at the current OEB-approved rates is 212.2%. This clearly demonstrates that current Large Use class rates are significantly above the cost of providing service to TMMC and should be significantly reduced to more closely reflect the actual cost of providing distribution service to TMMC.

Q. WHY SHOULD THE BOARD ADOPT THE TWO LARGE USE CLASSES/DIRECT ASSIGNMENT CLASS COST-OF-SERVICE STUDY PRESENTED IN SCHEDULE JP-11?

A. The Two Large Use Classes/Direct Assignment CCOSS presented in **Schedule JP-11** is consistent with the principles of cost causation while the Settlement CCOSS is not. This is because the Two Large Use Classes/Direct Assignment CCOSS recognizes TMMC's unique circumstances as follows:

- TMMC operates an LDG facility;
- TMMC is served directly from the Preston TS, and an outage at the station will shut down TMMC's operations;
- The M24 and M30 Feeders serve only TMMC, and an outage of these feeders would shut down TMMC's operations;
- The four upgraded meters serve only TMMC;
- Energy+ does not use any high voltage or underground distribution facilities (either conduit or conductors) to serve TMMC;
- TMMC made a specific capital contribution to pay for the radial distribution system installed by Energy+ to serve TMMC. This radial system is not part of an integrated distribution network; and
- The costs of these dedicated facilities that serve only TMMC (*i.e.,* the M24 and M30 Feeders, the meters, and TMMC's capital contribution) can be identified and directly assigned to TMMC.

These unique circumstances applicable to TMMC are clearly recognized in **Schedule JP-11**.

3. SUPPLEMENTARY DISTRIBUTION SERVICE RATE DESIGN

Q. HAVE YOU UPDATED YOUR RECOMMENDED SUPPLEMENTARY DISTRIBUTION SERVICE RATE DESIGN?

A. Yes. I have updated my rate design based on the results of my Two Large Use Classes/Direct Assignment study (**Schedule JP-11**). I have also revised my recommendations in order to reflect what I now understand to be Board policy.

The first revision was to set the Large Use class target revenue requirement to achieve a 1.15 revenue-to-cost ratio as opposed to the 1.0 ratio assumed in my original evidence. This reflects the Board's policy that out-of-range revenue-to-cost ratios should be brought to the edge of the OEB-approved range (85% to 115%) as opposed to the mid-point of the range.

The second revision is with my recommendation that the monthly Large Use class Service Charge be reduced by 50%. I am now recommending no change in the current OEB-approved Service Charge in order to reflect the Board's guidance in this regard. Under this guidance, if a distributor's current fixed charge for any non-residential class is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling for any non-residential class at the current OEB-approved rate.[15] As discussed later, I still have concerns about whether the current Service Charge should be retained based on the results of my revised CCOSS.

[15] OEB *Filing Requirements for Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications*, Chapter 2 at 50 (Jul. 12, 2018).

Q. ARE THE SAME TWO CHANGES ALSO REFLECTED IN UPDATED SCHEDULE JP-6 PROVIDED IN APPENDIX C?

A. Yes.

Q. WHAT ARE YOUR SPECIFIC CONCERNS ABOUT APPLYING THE BOARD'S GUIDANCE ON ADJUSTMENTS TO FIXED CHARGES IN THIS PROCEEDING?

A. I would observe that applying the OEB's guidance would result in a *maximum* monthly fixed charge for TMMC of approximately $244 per month based on the Two Large Use Classes/Direct Assignment study shown in **Schedule JP-11**.[16] By contrast, the maximum monthly fixed charge for the other Large Use customer would be $878 per month.[17] Not only is there a substantial difference in the cost-based monthly fixed charge between TMMC and the other Large Use customer, the current OEB-approved $8,976.07 Large Use Service charge is clearly excessive. Thus, my first concern is that retaining the current Service Charge would not be consistent with designing cost-based rates. My second concern is that there is a significant difference between the TMMC and other Large Use customer monthly fixed charge. This difference supports establishing a separate TMMC customer class.

Q. PLEASE DESCRIBE YOUR REVISED RATE DESIGN RECOMMENDATIONS.

A. **Schedule JP-13** shows the derivation of my recommended rate design for Supplementary Distribution service provided to TMMC. To be clear, the term "Supplementary" refers to the "regular" Distribution service provided to a customer for load that is not otherwise supplied from the customer's LDG facilities.

[16] **Schedule JP-11** Workpaper, Sheet O2: Monthly Fixed Charge Min & Max Worksheet.

[17] *Id.*

Q. PLEASE DISCUSS SCHEDULE JP-13.

A. **Schedule JP-13** is based on a target revenue requirement of $420,157. This amount was derived from **Schedule JP-11** and adjusted to result in a 1.15 revenue-to-cost ratio. A summary of my recommended TMMC rate design is provided in Table 10.

Table 10
Recommended TMMC Rate Design

Rate	Allocated Cost	Target Revenues	Rate	Units	Reference
	(1)	(2)	(3)	(4)	(5)
Revenue Requirement	$391,949	$420,157			Sch. 11, Row 40 Sch. 13, pg. 1, Line 5
Service Charge		$107,713	$8,976.07	Per Month	Sch. 13 pg. 1, Line 6
Distribution Volumetric Rate		$312,444	[redacted]	Per kW	Sch. 13, pg. 1, Line 10

The Distribution Volumetric Rate would recover $312,444 (based on using the currently OEB-approved Service Charge).

Q. HOW WAS THE DISTRIBUTION VOLUMETRIC RATE WITH STANDBY SERVICE DERIVED?

A. The proposed Distribution Volumetric Rate was designed to recover the cost of the M24 and M30 Feeders used exclusively by TMMC. The cost of these Feeders is fixed because they were installed prior to when TMMC energized its LDG facilities and, consequently, there is more than sufficient capacity to serve TMMC's total (Supplementary and Standby service) requirements even if one or both of its LDG units were out of service. In other words, there are no incremental costs to provide Standby service to TMMC. Accordingly, the Distribution Volumetric Rate should account for the amount of TMMC's Contract Standby Demand. As discussed later, I have assumed that TMMC would contract for 6,900 kW of Standby service.

Q. IN YOUR ORIGINAL WRITTEN EVIDENCE, YOU RECOMMENDED THREE SEPARATE VOLUMETRIC RATES FOR SUPPLEMENTARY DISTRIBUTION SERVICE. WHY ARE YOU NOW RECOMMENDING A SINGLE VOLUMETRIC RATE?

A. The three volumetric rate structure set out in **Schedule JP-6** of my original written evidence served two purposes:

- It recognized the different types of distribution service (and different associated costs) provided to the two Large Use class customers; and
- It separated the local distribution costs (*i.e*., the costs associated with facilities that only serve a specific customer) from the shared distribution costs (*i.e.*, the costs associated with facilities that serve multiple customers).[18]

In my original written evidence, the >50 kV distribution facilities were assumed to be shared assets while all other distribution facilities were assumed to be local. Based on new information provided to me since my initial written evidence was submitted, it is clear that the only shared distribution facilities used to serve TMMC are the poles that support multiple feeders, including the M24 and M30 Feeders that are exclusively used to serve TMMC. Moreover, there are no Energy+ >50 kV distribution facilities connected to the TMMC radial distribution system. Finally, it is now unnecessary to distinguish between Primary Substation and Primary Distribution services because the rate design presented in **Schedule JP-13** only applies only to TMMC.

[18] The three volumetric rates were designed to recover (1) the costs of the shared (*i.e.,* Bulk Distribution) facilities, (2) the costs of the local (*i.e.,* Primary Substation) distribution facilities used to serve TMMC, and (3) the costs of the local (*i.e.,* Primary Distribution) facilities used to serve the other Large Use customer.

4. STANDBY DISTRIBUTION SERVICE RATE DESIGN

Q. DO YOU AGREE WITH THE STANDBY RATE DESIGN PROPOSED BY ENERGY+ IN THIS PROCEEDING?

A. No. I have many concerns with Energy+'s proposed rate for Standby Distribution service. These concerns are described in detail in my original evidence. For ease of reference, I have summarized my concerns in **Appendix D-2** of this updated evidence. My principal concern is that Energy+'s proposed Standby rate design does not reflect cost-causation principles and, accordingly, should not be accepted by the Board.

Q. ARE YOU RECOMMENDING A TMMC-SPECIFIC RATE DESIGN FOR STANDBY DISTRIBUTION SERVICE BASED ON THE TWO LARGE USE CLASSES/DIRECT ASSIGNMENT STUDY?

A. Yes. **Schedule JP-14** is a new version of **Schedule JP-8** from my original evidence. It shows the derivation of my recommended rate design for Standby Distribution service applicable to TMMC.[19] As in my original evidence, the Standby Distribution service rate design is derived from my recommended rate design for Supplementary Distribution service. To be clear, the term "Standby" refers to the additional delivery service required when TMMC's LDG sustains an outage and there is a net increase in TMMC's peak demand as a result of the outage.

Q. IS YOUR PROPOSED STANDBY DISTRIBUTION RATE DESIGN CONSISTENT WITH COST-CAUSATION PRINCIPLES?

A. Yes. **Appendix E** of this updated evidence provides an overview of the cost-causation

[19] For continuity and completeness, **Schedule JP-8** from my original evidence was further updated to reflect the changes made to **Schedule JP-6**. These updated schedules are provided in **Appendix C**.

principles that underlie my proposed design of cost-based rates for Standby Distribution service. The cost-causation principles recognize the following.

Standby Distribution is the *additional* delivery service required when a customer's LDG sustains an outage *and* there is a net increase in the customer's peak demand previously established during the billing month when there were no outages. Generator outages can be either *forced* or *scheduled*. Forced outages are random, non-recurring events, while scheduled outages are typically planned (sometimes well) in advance. For this reason, it cannot be assumed that forced outages always occur coincident with a system peak, while scheduled outages would seldom, if ever, coincide with a system peak. Accordingly, Standby Distribution service has much greater "diversity" than Supplementary Distribution service.

This greater diversity should be recognized in designing a cost-based Standby Distribution service rate. Local distribution costs are allocable to LDG regardless of the amount of Standby Distribution service actually provided. However, because of diversity, the amount of shared distribution costs allocable to LDG should reflect the amount of service provided; that is, the more that Standby Distribution service is used, the more likely an outage will coincide with a system peak and the higher the allocable distribution costs.

Applying the above cost-causation principles, a cost-based rate for Standby Distribution service should then consist of two separate charges:

- A Contract Volumetric Rate to recover the cost of local distribution facilities;[20] and

[20] In my original written evidence, I used the term Maximum Volumetric Rate, which has the same meaning as Contract Volumetric Rate.

- A Daily Volumetric Rate to recover the cost of shared distribution facilities.

The Contract Volumetric Rate would apply regardless of when or how often Standby Distribution service is provided. The Daily Volumetric Rate would apply when Standby Distribution service is actually used. Thus, customers using more Standby Distribution service would pay more than customers that use little or no Standby Distribution service. Further, to ensure that a LDG customer does not pay more for Standby Distribution service than for a comparable amount of Supplementary Distribution service, the sum of the Contract and Daily Volumetric Rate applied in any month would not exceed the otherwise applicable Distribution Volumetric Rate. In other words, a customer that uses Standby Distribution service for an entire month would pay the same total volumetric charges as would a similarly sized customer taking only Supplementary Distribution service.

Q. REFERRING TO SCHEDULE JP-14, HOW DID YOU DERIVE THE CONTRACT VOLUMETRIC RATE?

A. The recommended Contract Volumetric rate is $[redacted] per kW. This rate recovers the cost of the local distribution facilities directly assigned to TMMC and the corresponding overhead costs. The derivation of the rate is shown in **Schedule JP-13,** page 1 (line 9). It assumes that TMMC will establish a Standby Contract Demand of 6,900 kW. This would be in addition to TMMC's Supplementary service billing demand which is derived in **Schedule JP-13**, page 2.

Q. HOW DID TMMC DETERMINE THAT IT WOULD ESTABLISH A STANDBY CONTRACT DEMAND OF 6,900 KW?

A. I am advised by TMMC that the 6,900 kW Standby Contract Demand reflects a combination of factors:

- TMMC's outage history (*i.e.,* **Schedule JP-7**);
- The fact that outages are unlikely to coincide with the monthly peak demand; and
- The low probability of a simultaneous outage of both LDG units.

Q. HOW DID YOU DERIVE THE DAILY VOLUMETRIC RATE?

A. As previously explained, the Daily Volumetric Rate applicable to TMMC is designed to recover shared facilities costs, which in the case of TMMC are the costs of the primary poles allocated to TMMC. The allocated costs were derived from the Two Large Use Classes/Direct Assignment study. As shown on **Schedule JP-14** (line 2), the corresponding annual unit cost is $[redacted] per kW-month. The [redacted] monthly charge was then restated into a Daily Volumetric Rate by dividing $[redacted] by the number of weekdays in a typical billing month, or 20.9 (line 3). Thus, the Daily Volumetric rate applicable to TMMC would be $[redacted] per kW-Day line 4).

Q. WHEN WOULD THE DAILY VOLUMETRIC RATE APPLY?

A. The Daily Volumetric Rate would apply when the customer uses Standby Distribution service; that is, when the customer establishes a higher monthly peak demand while it is also experiencing a generator outage. The customer would have to notify Energy+ when an outage occurs and when the LDG has been fully restored. The daily demand would be the difference between the monthly peak demand established during an outage and the previously established monthly peak demand.

Further, the Daily Volumetric Rate would only apply during weekdays, excluding public holidays. This would provide a price signal to encourage a customer to schedule or defer outages to the off-peak hours.

Q. CAN THE GENERAL APPROACH DESCRIBED IN SCHEDULE JP-14 ALSO BE USED TO DESIGN STANDBY RATES FOR OTHER CUSTOMER CLASSES?

A. Yes. The Contract Volumetric Rate for each class would be designed to recover the costs of local distribution facilities used to serve that class. Because Energy+'s other end-use customer classes are served from an integrated (rather than radial) system, the local distribution facilities could include primary and secondary distribution, while the shared facilities would include >50 kV (and, possibly, certain primary distribution facilities). The derivation of the applicable rate for the GS 50 – 999 kW class is illustrated in **Schedule JP-15**.

Q. HOW DID YOU DERIVE THE CONTRACT VOLUMETRIC RATE FOR THE GS 50 – 999 KW CLASS?

A. Referring to **Schedule JP-15**, page 1, the Contract Volumetric Rate is based on the assumption that local distribution facilities include both Primary and Secondary demand-related costs (line 1) and on the test-year billing demand (line 2). Using the CCOSS in **Schedule JP-11**, the GS 50 – 999 kW class was allocated local distribution costs of $4.360 million (line 1). The derivation of the $4.360 million of allocated local distribution costs is shown in **Schedule JP-15**, page 2. The Contract Volumetric Rate of $2.779 per kW (page 1, line 3) was derived by dividing the allocated local distribution costs (line 1) by the test-year billing determinants (line 2).[21]

Q. HOW DID YOU DERIVE THE DAILY VOLUMETRIC RATE FOR THE GS 50 – 999 KW CLASS?

A. The Daily Volumetric rate is based on the cost of Energy+'s shared distribution facilities (**Schedule JP-15**, page 1, line 4). Based on the Settlement Proposal, the cost of these facilities is $1.382 million. The components of the $1.382 million are shown in **Schedule JP-15**, page 3.

Referring again to **Schedule JP-15**, page 1, I then divided this amount by the total 12CP demand of 2,528,721 (line 5) to derive a system unit cost of $0.547 per kW-month (line 6). The final step was to restate the system unit cost to an equivalent cost for secondary voltage by applying the applicable secondary voltage distribution loss factor (line 7). This resulted in a charge of $0.561 per kW-month (line 8). The $0.561 monthly charge can then be restated into a Daily Volumetric Rate by dividing the former by the number of weekdays in a typical billing month, or 20.9 (line 9). This will result in a Daily Volumetric rate of $0.027 per kW-Day (line 10).

Q. COULD THE SAME PROCESS BE USED TO ESTABLISH STANDBY RATES FOR ANY CUSTOMER CLASS?

A. Yes. The process illustrated in **Schedule JP-15** would apply equally to all (non-TMMC) customer classes. In fact, because the Daily Volumetric rate is based on

[21] In the work papers to **Schedule JP-11**, I have created a new worksheet (Local Shared Costs) that can be used to derive the Contract Volumetric Rate for the other general service classes using the same methodology as shown in **Schedule JP-15**.

system-wide costs, the same rate would apply to all classes taking Secondary Distribution service.

Q. ARE THERE ANY OTHER FACETS OF YOUR PROPOSED TMMC STANDBY RATE DESIGN?

A. Yes. First, TMMC's proposed Daily Volumetric Rate would have a "demand forgiveness" provision. If a customer establishes a higher peak demand during off-peak hours, that higher demand would be ignored and would not result in resetting the Contract Demand or establishing a higher daily demand in the billing month.

However, if the daily demand were to exceed the Standby Contract Demand and absent any extenuating circumstances (such as a safety issue or other emergency condition on either the TMMC or Energy+ facilities), the Standby Contract Demand would be increased. This "ratchet" provision would provide an incentive for TMMC to manage its operating load during generator outages. The Standby Contract Demand could be reset for the following calendar year by mutual agreement between Energy+ and TMMC.

Q. WHY SHOULD THE BOARD ADOPT YOUR RECOMMENDED STANDBY DISTRIBUTION SERVICE RATE DESIGN FOR TMMC?

A. My proposed Standby rate design methodology appropriately recognizes the characteristics of Standby Distribution service (*i.e.*, forced outages are random, non-recurring events) while adhering to the same cost-causation principles used to design cost-based rates for Supplementary Distribution service. Further, the methodology is consistent with the ratemaking practices adopted by several U.S. state regulatory commissions and with the U.S. Federal Energy Regulatory Commission rules that apply to the provision of standby service to Qualifying Facilities.[22]

Q. WOULD APPLYING YOUR RECOMMENDED TMMC STANDBY DISTRIBUTION SERVICE RATE RESULT IN ADDITIONAL REVENUES FOR ENERGY+?

A. Yes. **Schedule JP-16** is an update of my original **Schedule JP-9**. It quantifies the revenues that would be derived from implementing my recommended TMMC Standby Distribution service rate during the test year. As discussed in my original written evidence, any revenues derived from the Daily Volumetric Rate should be used to offset Energy+'s test-year revenue requirement. The revenues from the Contract Volumetric Rate were already accounted for in my recommended TMMC rate design for Supplementary Distribution service (**Schedule JP-13)**.

[22] 18 C.F.R. §.292.305 (Apr. 2018).

5. CONCLUSION

Q. BASED ON YOUR UPDATED WRITTEN EVIDENCE AND RECOMMENDATIONS, WHAT FINDINGS SHOULD THE BOARD MAKE?

A. The Board should make the following findings in lieu of the findings identified in my original written evidence:

- Reject the Settlement CCOSS;
- Adopt the Two Large Use Classes/Direct Assignment CCOSS in which: (i) TMMC is a separate customer class; (ii) all costs incurred to serve TMMC (with the sole exception of primary poles) are directly assigned to TMMC; (iii) TMMC's loads are removed from the allocation of Primary Distribution costs (*i.e.*, overhead lines and conductors; underground conduit; and underground conductors); (iv) TMMC's 4NCP demands are derived from the historical load profiles and do not include an LDG adjustment; and (iv) all Large Use class loads are removed from the allocation of >50 kV Distribution costs.
- Establish a target revenue requirement for TMMC based on a 1.15 revenue-to-cost ratio.
- Approve a just and reasonable cost-based rate design for Supplementary Distribution service provided to TMMC consisting of a cost-based Service Charge consistent with the Board's guidance and a Distribution Volumetric Rate to recover the remaining revenue requirements not already collected in the Service Charge.
- Implement a just and reasonable cost-based Standby Distribution service rate design for TMMC comprised of Contract Volumetric and Daily Volumetric Rates, where the former recovers the cost of local distribution facilities applied to TMMC's designated Standby Contract Demand and the latter is based on the cost of the shared distribution facilities applied to the amount of daily Standby Distribution service (and is capped at the otherwise applicable TMMC Distribution Volumetric Rate).

- Define Standby Distribution service as the *additional* delivery service required when a customer's LDG sustains an outage *and* there is a net increase in the customer's peak demand previously established during the billing month when there were no outages.

Q. DOES THIS COMPLETE YOUR UPDATED WRITTEN EVIDENCE?

A. Yes.

APPENDIX C

Updated Schedules of Jeffry Pollock

Updated Schedule	Begins on Page No.
Schedule JP-5	36
Schedule JP-6	38
Schedule JP-8	42
Schedule JP-9	43

Schedule JP-5 Update
Page 1 of 2

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0028

Sheet O1 Revenue to Cost Summary Worksheet - 1 Lg Use Class/Partial Direct Assignment

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	5	6	7	8
Line	**Description**	**Total**	**Residential**	**GS <50**	**GS> 50- 999 kW**	**GS> 1,000 - 4,999 kW**	**Large Use**	**Street Light**	**Sentinel**
1	Distribution Revenue at Existing Rates	$33,458,220	$17,528,595	$4,131,617	$7,466,138	$2,140,493	$1,040,061	$671,811	$14,573
2	Miscellaneous Revenue (mi)	$2,025,568	$1,371,171	$222,157	$237,420	$86,915	$42,333	$56,500	$1,325
		Miscellaneous Revenue Input equals Output							
3	**Total Revenue at Existing Rates**	**$35,483,788**	**$18,899,765**	**$4,353,775**	**$7,703,558**	**$2,227,408**	**$1,082,393**	**$728,311**	**$15,898**
4	Factor required to recover deficiency (1 + D)	1.0250							
5	Distribution Revenue at Status Quo Rates	$34,296,049	$17,967,529	$4,235,078	$7,653,098	$2,194,094	$1,066,105	$688,634	$14,938
6	Miscellaneous Revenue (mi)	$2,025,568	$1,371,171	$222,157	$237,420	$86,915	$42,333	$56,500	$1,325
7	**Total Revenue at Status Quo Rates**	**$36,321,617**	**$19,338,700**	**$4,457,235**	**$7,890,518**	**$2,281,009**	**$1,108,437**	**$745,134**	**$16,263**
	Expenses								
8	Distribution Costs (di)	$4,813,774	$2,872,134	$488,219	$893,859	$354,635	$98,795	$88,526	$4,049
9	Customer Related Costs (cu)	$4,893,912	$3,856,744	$634,958	$289,309	$88,275	$16,000	$1,531	$181
10	General and Administration (ad)	$8,632,229	$5,880,495	$985,913	$1,063,153	$396,853	$175,903	$82,128	$3,853
11	Depreciation and Amortization (dep)	$6,369,513	$3,704,737	$781,088	$1,206,879	$412,231	$130,914	$102,912	$5,021
12	PILs (INPUT)	$774,133	$442,228	$85,073	$153,713	$54,735	$16,560	$14,756	$683
13	Interest	$4,384,511	$2,504,676	$481,836	$870,598	$310,005	$93,792	$83,575	$3,870
14	**Total Expenses**	**$29,868,071**	**$19,261,013**	**$3,457,089**	**$4,477,511**	**$1,616,734**	**$531,963**	**$373,427**	**$17,657**
15	**Direct Allocation**	**$233,895**	**$0**	**$0**	**$0**	**$0**	**$91,933**	**$0**	**$0**
16	Allocated Net Income (NI)	$6,219,650	$3,553,009	$683,509	$1,234,987	$439,758	$133,048	$118,555	$5,490
17	**Revenue Requirement (includes NI)**	$36,321,617	$22,814,022	$4,140,598	$5,712,498	$2,056,492	$756,944	$491,981	$23,148
	Rate Base Calculation								
	Net Assets								
18	Distribution Plant - Gross	$198,250,615	$114,387,820	$22,303,770	$39,049,018	$13,898,585	$4,067,025	$3,767,383	$173,042
19	General Plant - Gross	$15,515,902	$8,905,403	$1,711,344	$3,056,443	$1,080,860	$316,820	$297,781	$13,776
20	Accumulated Depreciation	($25,192,183)	($14,378,065)	($3,086,912)	($4,765,519)	($1,783,009)	($616,792)	($422,523)	($18,321)
21	Capital Contribution	($32,252,689)	($19,098,242)	($3,650,469)	($6,137,144)	($2,088,838)	($500,835)	($645,415)	($29,701)
22	**Total Net Plant**	**$156,321,645**	**$89,816,915**	**$17,277,732**	**$31,202,798**	**$11,107,599**	**$3,266,218**	**$2,997,226**	**$138,795**
23	**Directly Allocated Net Fixed Assets**	**$874,567**	**$0**	**$0**	**$0**	**$0**	**$90,038**	**$0**	**$0**
24	**Working Capital**	**$16,695,208**	**$5,238,320.83**	**$1,953,193**	**$4,706,578**	**$2,181,790**	**$1,368,873**	**$47,999**	**$1,779**
25	**Total Rate Base**	**$173,891,421**	**$95,055,236**	**$19,230,925**	**$35,909,375**	**$13,289,389**	**$4,725,129**	**$3,045,225**	**$140,574**
26	**REVENUE TO EXPENSES STATUS QUO%**	**100.00%**	**84.77%**	**107.65%**	**138.13%**	**110.92%**	**146.44%**	**151.46%**	**70.26%**

Schedule JP-5 Update
Page 2 of 2

Ontario Energy Board

2019 Cost Allocation Mode

EB-2018-0028

Sheet O1 Revenue to Cost Summary Worksheet - 1 Lg Use Class/Partial Direct Assignment

Class Revenue, Cost Analysis, and Return on Rate Base

			9	10	12	13	14	15
Line	Description	Total	Unmetered Scattered Load	Embedded Distributor Hydro One - CND	Embedded Distributor Waterloo North Hydro - CND	Embedded Distributor Hydro One 1 - BCP	Embedded Distributor Brantford Power - BCP	Embedded Distributor Hydro One 2 - BCP
1	Distribution Revenue at Existing Rates	$33,458,220	$64,042	$50,527	$221,287	$119,034	$5,388	$4,655
2	Miscellaneous Revenue (mi)	$2,025,568	$4,676	$631	$1,655	$359	$200	$225
		M						
3	**Total Revenue at Existing Rates**	**$35,483,788**	**$68,718**	**$51,157**	**$222,942**	**$119,393**	**$5,588**	**$4,880**
4	Factor required to recover deficiency (1 + D)	1.0250						
5	Distribution Revenue at Status Quo Rates	$34,296,049	$65,646	$51,792	$226,828	$122,014	$5,523	$4,772
6	Miscellaneous Revenue (mi)	$2,025,568	$4,676	$631	$1,655	$359	$200	$225
7	**Total Revenue at Status Quo Rates**	**$36,321,617**	**$70,322**	**$52,422**	**$228,484**	**$122,374**	**$5,723**	**$4,997**
	Expenses							
8	Distribution Costs (di)	$4,813,774	$13,558	$0	$0	$0	$0	$0
9	Customer Related Costs (cu)	$4,893,912	$1,388	$2,394	$405	$405	$701	$1,620
10	General and Administration (ad)	$8,632,229	$13,568	$6,029	$17,539	$3,601	$1,820	$1,375
11	Depreciation and Amortization (dep)	$6,369,513	$16,819	$2,897	$4,555	$863	$598	$0
12	PILs (INPUT)	$774,133	$2,289	$680	$2,703	$512	$200	$0
13	Interest	$4,384,511	$12,966	$3,850	$15,310	$2,900	$1,133	$0
14	**Total Expenses**	**$29,868,071**	**$60,589**	**$15,850**	**$40,511**	**$8,281**	**$4,453**	**$2,995**
15	**Direct Allocation**	**$233,895**	**$0**	**$22,003**	**$95,172**	**$18,028**	**$6,758**	**$0**
16	Allocated Net Income (NI)	$6,219,650	$18,393	$5,461	$21,717	$4,114	$1,608	$0
17	**Revenue Requirement (includes NI)**	$36,321,617	$78,981	$43,314	$157,401	$30,423	$12,819	$2,995
	Rate Base Calculation							
	Net Assets							
18	Distribution Plant - Gross	$198,250,615	$579,115	$21,634	$0	$0	$3,224	$0
19	General Plant - Gross	$15,515,902	$46,015	$14,550	$57,702	$10,931	$4,278	$0
20	Accumulated Depreciation	($25,192,183)	($62,452)	($15,601)	($33,167)	($6,283)	($3,537)	$0
21	Capital Contribution	($32,252,689)	($97,756)	($3,732)	$0	$0	($556)	$0
22	**Total Net Plant**	**$156,321,645**	**$464,921**	**$16,851**	**$24,535**	**$4,648**	**$3,408**	**$0**
23	**Directly Allocated Net Fixed Assets**	**$874,567**	**$0**	**$121,596**	**$525,953**	**$99,631**	**$37,349**	**$0**
24	**Working Capital**	**$16,695,208**	**$23,144**	**$117,397**	**$539,490**	**$113,187**	**$3,503**	**$399,954**
25	**Total Rate Base**	**$173,891,421**	**$488,065**	**$255,844**	**$1,089,979**	**$217,466**	**$44,260**	**$399,954**
26	**REVENUE TO EXPENSES STATUS QUO%**	100.00%	**89.04%**	121.03%	145.16%	402.24%	44.65%	166.86%

Schedule JP-6 Update
Page 1 of 4

ENERGY+, Inc.

Recommended Large Use Class Rate Design

Line	Description	Cost	Billing Units		Rate	Reference
		(1)	(2)		(3)	(4)
1	**Revenue Requirement**	$828,153				Schedule JP-6, page 2
	Service Charge:					
2	Present Rates				$8,976.07	Appilcation Exhibit 8 at 10
3	Recommended Rates	$215,426	24	Bills	$8,976.07	No Change
4	**Revenues to be Recovered In Distribution Volumetric Rates**	$612,727				Line 1 - Line 3
5	**Total Demand-Related Costs**	$659,936				Page 2
6	**Revenue-to-Cost Ratio**	92.8%				Line 4 ÷ Line 5
7	**Shared Facilities Cost**	$159,073	[redacted]	kW	[redacted]	Col. 1 ÷ Col. 2
	Local Facilities Cost:					
8	Feeder Costs	$98,919	[redacted]	kW	[redacted]	(Line 6 x Schedule JP-6, Line 12, Col. 6) ÷ Col. 2
9	Poles, Towers, & Fixtures	$110,250		kW		(Line 6 x Schedule JP-6, page 3, Line 5) ÷ Col. 2
10	**Primary Substation Volumetric Rate**	$190,877				Col. 1 = Col. 2 x Col. 3 Col. 3 = Sum Lines 8:9
11	**Primary Distribution Volumetric Rate**	$262,778		kW		(Line 4 - Line 7 - Line 10) ÷ Col. 2

Sources:

(1) Schedule JP-6, page 2 x Line 6.

(2) Schedule JP-6, page 4.

Schedule JP-6 Update
Page 2 of 4

ENERGY+, Inc.

Large Use Class Revenue Requirement By Component
Based on TMMC's Revised Class Cost-of-Service Study

Line	Description	Total Large Use Class	Customer-Related Costs	Total Demand-Related Costs	Shared Facilities (Bulk Distribution) Costs	Local Facilities: All Other Costs	Local Facilities: TMMC Feeder Costs
		(1)	(2)	(3)	(4)	(5)	(6)
1	Distribution Costs	$98,795	$32	$98,763	$30,757	$68,006	
2	Customer-Related Costs	$16,000	$16,000	$0	$0	$0	
3	General & Administrative	$175,903	$24,553	$49,850	$15,524	$34,326	
4	Depreciation & Amortization	$130,914	$15,492	$115,422	$38,191	$77,231	
5	PILS	$16,560	$1,219	$15,341	$4,565	$10,776	
6	Interest Expense	$93,792	$6,903	$86,889	$25,858	$61,031	
7	Total Expenses	$531,963	$64,197	$366,265	$114,895	$251,370	$0
8	Direct Allocation	$91,933	$0	$91,933	$0	$0	$91,933
9	Allocated Net Income	$133,048	$9,792	$123,256	$36,680	$86,576	$0
10	Miscellaneous Revenue	$42,333	$30,336	$11,997	$3,736	$8,261	
11	Revenue Requirement at Cost	$714,611	$43,653	$569,458	$147,839	$329,685	$91,933
12	Rev. Req. at 1.15 RCR*	$828,153	$50,589	$659,936	$171,329	$382,067	$106,540

Source: Schedules JP-3 and JP-5.

*	Revenue Requirement incl NI	$756,944
	Revenue-to-Cost Ratio (RCR)	1.15
	Revenue Requirement	$870,486
	Less: Misc. Revenue	$42,333
	Target Rate Design Revenue	$828,153

Schedule JP-6 Update
Page 3 of 4

ENERGY+, Inc.
Large Use Class:
Estimated Cost Primary Poles, Towers, and Fixtures
Based on TMMC's Revised Class Cost-of-Service Study

Line	Description	Amount	Reference
		(1)	(2)
1	Total Primary Distribution Costs	$382,067	Schedule JP-6, Line 12, Col. 5
	Gross Plant Investment:		
2	Primary Poles, Towers, & Fixtures	$18,839,131	Energy+ CCOSS
3	Total Primary Gross Plant Investment	$60,615,861	Energy+ CCOSS
4	Gross Plant Ratio	31.08%	Line 2 ÷ Line 3
5	Poles, Towers, & Fixtures Costs	$118,745	Line 1 x Line 4

Schedule JP-6
Page 4 of 4

ENERGY+, Inc.

Large Use Class Billing Demand
(Amounts in kW)

Line	Description	Amount	Reference
		(1)	(2)
1	Energy+ Projection	361,276	
2	Less: Energy+ LDG Adjustment	[redacted]	Schedule JP-1, Line 3, Col. 2 x 12
3	Supplementary Billing Demand	[redacted]	Line 1 + Line 2
4	Percent of Load at Primary Substation	[redacted]	Estimated
5	Primary Substation Billing Demand Supplemental	[redacted]	Line 3 x Line 4
6	Primary Distribution Billing Demand	[redacted]	Line 3 - Line 5
	Primary Substation - Feeder		
7	Base (Supplemental)	[redacted]	Line 5
8	Standby Contract Demand	55,200	4,600 kW
9	Total Primary Substation - Feeder Billing Demand	[redacted]	Sum Lines 7 - 8
	Primary Substation - Poles		
10	Base - Substation	[redacted]	Line 5
11	Standby Contract Demand	55,200	4,600 kW
12	Primary Distribution	[redacted]	Line 6
13	Total Primary Substation - Pole Billing Demand	386,032	Sum Lines 10 - 12

Schedule JP-8 Update
Page 1 of 1

ENERGY+, Inc.

Recommended Standby Service Rate Design

Line	Description	Rate	Reference
		(1)	(2)
1	**Contract Volumetric Rate**	[redacted]	Schedule JP-6, Page 1
	Daily Volumetric Rate:		
2	Local Facilities Unit Cost	[redacted]	Schedule JP-6, Page 1
3	No. of Weekdays Per Billing Month	20.9	
4	**Daily Volumetric Rate**	[redacted]	Line 2 ÷ Line 3
5	**Monthly Maximum Standby Volumetric Rate**	[redacted]	Sum Lines 1:2

REDACTED VERSION

ENERGY+, Inc.

Revenues From Recommended Standby Service Rate

Line	Description	Rate	Billing Units		Revenues	Reference
		(1)	(2)		(3)	(4)
1	**Contract Volumetric Rate**	[redacted]	55,200	kW	[redacted]	Schedule JP-8
2	**Daily Volumetric Rate**	$0.023	[redacted]	kW		Schedules JP-7 & JP-8
3	**Total Standby Service Revenues**					Sum Lines 1:2

APPENDIX D-1

Critique of Energy+'s Class Cost-of-Service Study

Q. WHAT ARE YOUR SPECIFIC CONCERNS ABOUT ENERGY+'S CLASS COST-OF-SERVICE STUDY?

A. Energy+'s CCOSS overstates the cost of serving the Large Use class for several reasons. First, Energy+ has erroneously adjusted the Large Use class 12CP, 4NCP and 12NCP demands that it uses to allocate demand-related costs in its CCOSS. These adjusted demands 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*. Moreover, Energy+'s LDG adjustments ignore the procedures that have been outlined by the Board for recognizing LDG in a CCOSS, and they ignore diversity.

Second, Energy+ failed to recognize that the specific distribution infrastructure it uses to serve TMMC is different from the infrastructure that it uses to serve the other Large Use customer. Specifically, TMMC is served directly from two dedicated feeders that extend from Hydro One's Preston TS to the TMMC plant. This type of distribution service can be described as "Primary Substation" service. The cost of the two dedicated feeders serving TMMC has been ascertained by Energy+ and, accordingly, should be directly assigned to TMMC. The other Large Use customer, by contrast, takes Primary Distribution service from an integrated primary distribution network.

Each of these flaws is discussed below.

Q. WHAT IS THE LARGE USE CLASS?

A. The Large Use class is a rate class comprised of two customers that each have peak demands of at least 5 MW. The class is served entirely at primary voltage, although, as previously stated and discussed in more detail below, the Energy+ infrastructure used to serve these two Large Use customers differs.

Load Displacement Generation Adjustments

Q. WHY DO YOU ASSERT THAT ENERGY+ HAS OVERSTATED THE LARGE USE CLASS DEMAND ALLOCATION FACTORS?

A. The demand allocation factors are overstated because they do not reflect the Large Use class's *actual* load characteristics as derived from the load profile analysis. Instead, they reflect unsupported assumptions about the timing, amount, and duration of the standby delivery service provided during outages of TMMC's LDG.

Q. WHAT DEMAND ALLOCATION FACTORS DOES ENERGY+ USE TO ALLOCATE DISTRIBUTION COSTS TO THE LARGE USE CLASS?

A. Energy+ uses the 12CP method to allocate Bulk Distribution costs and the 4NCP method to allocate Primary Distribution costs.

Q. DID ENERGY+ USE THE 12CP, 4NCP, AND 12NCP DEMANDS THAT WERE DERIVED FROM ENERGY+'S LOAD PROFILE ANALYSIS?

A. No. The 12CP, 4NCP, and 12NCP demands used in the Energy+'s CCOSS for the Large Use class are not the same as the 12CP, 4NCP, and 12NCP demands derived in Energy+'s load profile. Instead, Energy+ adjusted these load profile demands for the assumed impact of TMMC's LDG. The specific LDG adjustments are shown on Table 1.

Table 1
Derivation of Adjusted 12CP, 4NCP and 12NCP Demands
Large Use Class
(kW)

Description	12CP	4NCP	12NCP
Per Load Profile	259,575	102,987	286,587
Energy+ LDG Adjustments	[redacted]		
Per Updated CCOSS			

Source: 2019 EnergyPlus Load Profile Model 2006 Hydro One data for 2019_IRR_20180914; Cost Allocation Model Schedule I-18; Energy+ Response to IR-TMMC-4.

Q. WHAT IS THE BASIS FOR ENERGY+'S LDG ADJUSTMENTS?

A. Energy+ observed that in calendar year 2017, TMMC reached an annual peak demand of approximately [redacted] MW.[7] The actual peak demand was [redacted] kW. This annual peak demand occurred on Wednesday, November 8, 2017 at 8 am.

Q. HOW DID ENERGY+ DETERMINE THAT LDG WOULD INCREASE THE LARGE USE CLASS'S TWELVE MONTH LOADS BY PRECISELY [redacted] KW?

A. The derivation of the Energy+ LDG adjustments is shown in **Schedule JP-1**. It shows TMMC's monthly peak demands for calendar years 2016, 2017, and six months of 2018. TMMC's annual peak demand is shown in column 1, and its average monthly peak demand is shown in column 2. Column 3 shows the difference between columns 1 and 2.

For example, in 2017, TMMC's peak demand was [redacted] kW, while its average monthly peak demand was [redacted] kW (line 2). This reflects a difference of [redacted] kW (column 3, line 2). Energy+'s proposed [redacted] kW adjustment to both the 12CP and 12NCP demands is exactly the product of [redacted] kW and 12 (line 5).

[7] Energy+ Response to IR-TMMC-9, Sub-Question vii.

Q. SCHEDULE JP-1 SHOWS THAT TMMC IMPOSED A NET PEAK DEMAND OF APPROXIMATELY 28.8 MW IN 2016. DOESN'T ENERGY+ HAVE TO SIZE ITS DISTRIBUTION FACILITIES TO SERVE LOADS OF AT LEAST 28.8 MW?

A. No, it does not. The dedicated distribution feeders that serve TMMC were energized long before TMMC's LDG went into service on January 1, 2016.[8] Prior to installing that facility, TMMC's peak demand was as high as [redacted] MW.[9] Accordingly, the dedicated distribution feeders are already more than adequate to deliver TMMC's gross peak demand.

Q. ARE ENERGY+'S PROPOSED LDG ADJUSTMENTS REASONABLE?

A. No. The LDG adjustments shown in Table 1 above assume that an outage of TMMC's LDG would occur simultaneously with the Large Use class's coincident and non-coincident peak demands ***in each and every month***. This assumption is not supported by any analysis presented by Energy+ in its application. Accordingly, there is no basis for making the same LDG adjustment to the 12CP demands as Energy+ is proposing to make to the 4NCP and 12NCP demands. To do so would assume that Standby Distribution service has zero diversity.

Q. WHAT DO YOU MEAN BY DIVERSITY?

A. Diversity recognizes that individual customers experience their peak demands at different times. It can be expressed in several ways, as shown in Table 2.

---

[8] *Id.*
[9] Information provided by TMMC.

Table 2 Example of Demand Diversity			
Description	**Customer #1**	**Customer #2**	**Total Class**
Demand Coincident With the System Peak	50	50	100
Demand Coincident With the Class Peak	60	75	135
Maximum Demand	75	85	160
Diversity: Class Peak To Coincident Peak	1.20	1.25	1.35
Diversity: Maximum To Class Peak	1.25	1.13	1.18

One measure of diversity is the ratio of each customer's contribution to the class peak to the coincident peak. The corresponding diversity factors are 1.20 and 1.25 times, respectively, for Customer 1 and Customer 2. Overall, the class diversity is 1.35 times.

A second measure is the ratio of each customer's maximum demand to class peak demand. The corresponding diversity factors are 1.25 and 1.13 times, respectively, for Customer 1 and Customer 2. Overall, the class diversity is 1.18 times.

Because of diversity, coincident demands are lower than class peak demands, and class peak demands are lower than the sum of each customer's maximum demand.

Q. IS THERE ANY DIVERSITY WITHIN THE LARGE USE CLASS?

A. Yes. Table 3 below measures Energy+'s Large Use class demand diversity. As shown in Table 3, the diversity between the Large Use class's 12NCP and its 12CP is 1.10, while the diversity between the Large Use class's billing demand and the 12NCP demand is 1.15. Therefore, even a class comprised of only two customers can exhibit diversity.

Table 3
Large Use Class Demand Diversity
Excluding LDG Adjustments

Description	Demand (kW)	Diversity
12CP	259,575	N/A
12NCP	286,587	1.10
Billing Demand	[redacted]	1.15

Sources: 2019 EnergyPlus Load Profile Model
2006 Hydro One data for 2019_IRR_20180914;
Cost Allocation Model, Schedule 16.1 less 12NCP LDG adjustment;
and Energy+ Response to IR-TMMC-19.

Q. DO THE LOAD PROFILES USED BY ENERGY+ INCLUDE LDG?

A. No. Energy+ is using 2006 Hydro One data to project its 2019 load profile.[10] As previously stated, TMMC did not begin operation of its LDG until January 1, 2016. Thus, the diversity shown in Table 3 excludes the impact of LDG.

Q. HOW MIGHT LDG IMPACT DIVERSITY?

A. As discussed later, forced outages of generators are random, short-duration occurrences. Similarly, planned outages can be scheduled in advance to occur at times when capacity is readily available such as during the non-summer months and off-peak hours. Based on these assumptions, the addition of LDG will increase the diversity within the Large Use class. As demonstrated below, the higher the diversity, the lower the distribution volumetric rate required to recover the cost of providing Standby Distribution service.

[10] 2019 EnergyPlus Load profile model 2006 Hydro One data for 2019_IRR_20180914 provided in response to Staff IRs.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM ENERGY+'S PROPOSED LDG ADJUSTMENTS?

A. Energy+ failed to analyze the impact of LDG on the Large Use class's load characteristics. Absent such an analysis, it is impossible to precisely determine the amount of diversity associated with any Standby Distribution service that Energy+ provides to TMMC to replace its on-site generation.

Consistency With the Board's Directions

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT ENERGY+'S CLASS COST-OF-SERVICE STUDY?

A. Yes. Energy+'s LDG adjustments are contrary to the Board's directions on cost allocation. Specifically, with respect to LDG, the Board directed distributors to explain in its Filing Summary:

- What steps were taken to gather relevant data to assess the existence of diversity, and
- What steps were taken to reflect any diversity of generation in its filing.[11]

As previously stated, Energy+ assumed zero diversity for TMMC's generator outages, and it provided no explanation or evidentiary support for this assumption.

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:

[11] EB-2005-0317, Cost Allocation Review, *Board Directions on Cost Allocation Methodology for Electricity Distributors* at 23 (Sept. 29, 2006).

> 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.[12]

In other words, the first step is to determine a proper cost-based rate for providing Supplementary distribution service to the class, irrespective of the impact of LDG. Energy+ skipped this step because the CCOSS originally filed with its Application, as well as the CCOSS updated and filed on September 14, 2018, include erroneous and unsupported LDG adjustments to the Large Use class demand allocation factors. By skipping this step, Energy+ failed to follow the Board's direction.

Q. WHAT DO YOU MEAN BY SUPPLEMENTARY DISTRIBUTION SERVICE?

A. Supplementary distribution service is the amount of delivery service normally provided to a customer while its LDG is fully operational.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE ADJUSTMENTS PROPOSED BY ENERGY+?

A. The LDG adjustments should be removed from the CCOSS.

Direct Assignment

Q. SHOULD ANY OTHER CHANGES TO ENERGY+'S CLASS COST-OF-SERVICE STUDY ALSO BE CONSIDERED?

A. Yes. As discussed below, TMMC receives a different type of primary distribution service than the other Large Use customer. Further, most of the costs of the Energy+ distribution

[12] *Id.* at 92.

infrastructure used to serve TMMC can be directly assigned. The facilities used to serve TMMC are shown in **Schedule JP-2** attached to my original written evidence.

Schedule JP-2 is an electric single-line diagram that shows the delivery facilities that serve TMMC (page 1) and the other Large Use customer (page 2). Referring to page 1, TMMC is served directly from Hydro One's Preston TS through two dedicated 27.6 KV feeders, M24 and M30. These are the only Energy+ facilities that serve TMMC. Because of its direct connection to a Hydro One substation, TMMC is receiving Primary Substation service.

This is in stark contrast to Large Use Customer 2 (page 2), which takes primary distribution service through an integrated distribution system that serves other Energy+ customers. Hence, Customer 2 receives Primary Distribution service.

Q. IS A DIRECT ASSIGNMENT OF THE COSTS OF THE FEEDERS DEDICATED TO SERVING TMMC CONSISTENT WITH BOARD POLICY?

A. Yes. The Board has recognized that it may be appropriate to directly assign costs where there is evidence that a clearly identifiable and significant distribution facility can be tracked directly to a single rate classification.[15] The Board's directions on direct allocation state:

> When direct allocation is used, the distributor should consider whether it needs to adjust the appropriate allocation factors so that the rate classification to which costs for a specific function are directly allocated is not allocated further costs related to that function, except where there are joint costs that apply to the customer classification.[16]

---

[15] EB-2005-0317, Cost Allocation Review, *Board Directions on Cost Allocation Methodology for Electricity Distributors* (September 29, 2006) at 31.

[16] *Id*. at 32.

Q. IF THE COSTS OF THE FEEDERS DEDICATED TO SERVING TMMC ARE DIRECTLY ASSIGNED, HOW WOULD THIS CHANGE THE CLASS COST-OF-SERVICE STUDY?

A. With one exception, TMMC's load should be removed from the factors used to allocate all other primary distribution plant. The exception is with respect to Poles, Towers, and Fixtures – Primary (USoA 1830-4). TMMC should be considered in the allocation of the costs of these assets.

APPENDIX D-2

Critique of Energy+'s Proposed Standby Rate

Q. HOW IS ENERGY+ PROPOSING TO DESIGN A RATE FOR STANDBY DISTRIBUTION SERVICE?

A. Energy+ proposes to charge for Standby Distribution service by applying the otherwise applicable distribution volumetric rate to any portion of the LDG customer's Contract Demand in excess of the LDG customer's actual monthly peak demand. For TMMC, the otherwise applicable charge would be the Large Use Distribution Volumetric Rate. Energy+ initially set TMMC's Contract Demand to 28.8 MW.[21] It subsequently revised this to [redacted] MW in response to an interrogatory from TMMC.[22] The new lower Contract Demand reflects TMMC's maximum demand during calendar year 2017.

In effect, the Energy+ proposal involves "topping up" the distribution charges payable when the observed demand is less than the Contract Demand. The top-up would not be based on any measure of the actual amount of delivered standby power drawn. If, however, the LDG customer's actual peak demand in any month exceeds its Contract Demand (in which case there would be no shortfall between actual demand and Contract Demand), then the Distribution Volumetric rate would be applied only to the actual monthly peak demand. Finally, under Energy+'s Standby Distribution service rate design, an LDG customer's Contract Demand could be adjusted from time to time, presumably at Energy+'s discretion.

---

[21] Application, Exhibit 7 at 10.

[22] Energy+ Response to IR-TMMC-4.

Q. WHY IS ENERGY+ PROPOSING TO CHARGE THE SAME RATE FOR STANDBY DISTRIBUTION SERVICE AS FOR SUPPLEMENTARY DISTRIBUTION SERVICE?

A. Energy+ asserts that it has to reserve this capacity "…to ensure that the Energy+ infrastructure is in place at all times to provide the contracted peak load at any time."[23] Further, Energy+ asserts that establishing a [redacted] MW Contract Demand for TMMC is necessary in order to keep it whole with respect to the recovery of costs associated with peak demand.[24]

Q. DO YOU HAVE SPECIFIC CONCERNS WITH ENERGY+'S PROPOSED STANDBY DISTRIBUTION SERVICE RATE DESIGN?

A. Yes. First, as explained in more detail below, Energy+'s proposed Large Use Standby Distribution service rate design does not reflect cost-causation principles, and thus, would not result in a just and reasonable rate. Cost causation means recognizing how Standby Distribution service has different usage characteristics than Supplementary Distribution service because thermal LDGs, such as TMMC's LDG facility, are typically both highly efficient and reliable. This means that Standby Distribution service is used infrequently.

Second, Energy+ has provided no explanation for how it determined the Standby Contract Demand for TMMC. Typically such a determination is made in consultation with (rather than being imposed on) the LDG customer. Third, Energy+ ignored the reduction in the amount of capacity it has to reserve as a result of TMMC's

[23] Energy+ Response to IR-TMMC-1.

[24] Application, Exhibit 7 at 13.

LDG. With LDG reducing TMMC's net peak demand, more capacity is available to serve Energy+'s other customers.

Finally, Energy+'s proposed Standby Distribution service rate design would send the wrong price signals and discourage customers with LDG from scheduling outages in advance at times when the distribution system is not as stressed.

Cost Causation

Q. WHY DO YOU ASSERT THAT ENERGY+'S PROPOSED STANDBY RATE DESIGN IS NOT CONSISTENT WITH COST CAUSATION?

A. Energy+ used TMMC's maximum demand in 2017 to establish the Standby Contract Demand. As previously stated, both Energy+'s and TMMC's Revised CCOSSs allocated Bulk distribution facilities on a 12CP basis and Primary distribution facilities on a 4NCP and 12NCP (or class peak) basis. Thus, no distribution demand-related costs were allocated on the basis of a customer's highest recorded peak demand. Accordingly, a standby rate based solely on the highest recorded peak demand of one specific customer is not consistent with how demand-related costs were allocated to the Large Use class in either Energy+'s or TMMC's Revised CCOSSs.

Therefore, Energy+'s proposed Standby Distribution service rate design is both inconsistent with cost-causation principles and discriminatory as between an LDG customer and a non-LDG customer in the same rate class.

Standby Usage Characteristics

Q. SHOULD STANDBY DISTRIBUTION SERVICE BE PRICED THE SAME AS SUPPLEMENTARY DISTRIBUTION SERVICE?

A. No. Setting the same volumetric rate for both Standby and Supplementary distribution service assumes that Standby Distribution service has precisely the same usage characteristics as Supplementary Distribution service. The specific Energy+ proposed LDG adjustments were not based on any analysis of TMMC's load characteristics as would be necessary to estimate the expected amount of incremental load associated with the Standby Distribution service required by TMMC. Thus, Energy+'s assumption about TMMC's standby usage characteristics is simply unsupported.

Q. ARE THERE DIFFERENT TYPES OF STANDBY SERVICE?

A. Yes. Standby Distribution service consists of Backup service and Maintenance service.

Q. HOW ARE BACKUP SERVICE AND MAINTENANCE SERVICE DEFINED?

A. Backup service is the incremental delivery service required to provide electric energy or capacity to replace the energy or capacity that is unavailable due to an unscheduled or forced outage of the LDG. Thus, Backup service must be available at any time. Maintenance service, by contrast, is the incremental delivery service required to deliver electric energy or capacity supplied during a scheduled outage. Typically utilities will require self-generating customers to request Maintenance service in advance when there are adequate resources to accommodate a planned outage. This is often the characteristic that differentiates Maintenance service from Backup service.

Q. DO BACKUP SERVICE AND MAINTENANCE SERVICE HAVE THE SAME CHARACTERISTICS AS SUPPLEMENTARY SERVICE?

A. No. Backup service and Maintenance service are different from Supplementary service. Table 6 illustrates the differences.

Table 6
Relationship Between
Diversity Factor and Distribution Volumetric Rates

Customer	Class Peak Demand (kW)	Billing Demand (kW)	Diversity Factor	Allocated Demand Costs	Cost-Based Volumetric Rate
	(1)	(2)	(3)	(4)	(5)
1	1,000	2,000	2.00	$10,000	$5.00
2	1,000	1,250	1.25	$10,000	$8.00
3	1,000	10,000	10.00	$10,000	$1.00
Assumptions:			Col 2 ÷ Col 1	$30,000 allocated on Col 1	Col 4 ÷ Col 2

Table 6 shows the class peak and the billing demands of three customers. Each customer has the same class peak demand of 1,000 kW (column 1), but distinct billing demands of 2,000 kW, 1,250 kW, and 10,000 kW (column 2). Thus, there is substantial diversity within the class (column 3). Customers 1 and 2 purchase their full requirements; that is, they do not own LDG. Customer 3 owns LDG. The example further assumes that the utility has allocated $30,000 of demand-related costs to the class. Thus each customer is responsible for $10,000 of demand-related costs (column 4).

Because of varying diversity, the per-unit demand-related cost to serve each customer is different. Specifically, a cost-based volumetric rate would be $5 for Customer 1, $8 for Customer 2, and only $1 for Customer 3. In other words, a cost-based volumetric rate would be inversely proportional to each customer's diversity factor.

Q. WHY WOULD YOU ASSUME THAT A CUSTOMER WITH LDG WOULD HAVE A HIGHER DIVERSITY FACTOR?

A. Thermal LDG is typically very reliable and efficient. It would not be atypical for LDG facilities to operate at very high capacity factors and experience very low outage rates.

Thus, forced outages can be few and far between. Any maintenance outages could be planned well in advance because both the timing and duration of a maintenance outage can be reasonably estimated based on the scope of maintenance work to be performed on the LDG facility.

These characteristics mean that outages where replacement power is needed are unlikely to occur coincident with either a class peak or the distributor's system peak demands. In other words, customers with LDG facilities would more closely resemble Customer 3 than either Customers 1 or 2 in Table 6 above.

For this reason, it is unreasonable to levy the same Volumetric Rate for Standby Distribution service as for Supplementary Distribution service.

Q. HAVE YOU REVIEWED TMMC'S USE OF STANDBY DISTRIBUTION SERVICE?

A. Yes. **Schedule JP-7** provides an analysis of TMMC's use of Standby Distribution service for the period January 1, 2016 through June 30, 2018. The amount of Standby Distribution service used by TMMC is derived in column 3 and is the difference in the monthly maximum demands during periods when the generators were fully operational (column 1) and the maximum on-peak demands during periods when an outage occurred (column 2). Standby Distribution service only occurs when the customer sets a new monthly maximum demand because of a generator outage during on-peak hours. The outage duration is shown in column 4 and is measured using the number of on-peak days per month. Several conclusions can be drawn from **Schedule JP-7**.

First, there were no outages during on-peak hours in several months. Second, when outages occurred, they were of short duration. On average, TMMC experienced only two days of outage per month. Third, on some occasions when an outage occurred, it did not result in TMMC setting a new on-peak demand. On average, TMMC's on-peak maximum demand was less than 1,500 kW higher due to generator outages.

These statistics demonstrate that, contrary to Energy+'s LDG adjustments, Standby Distribution service did not impact peak demand equally in every month.

Energy+'s Make Whole Assertion

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 Energy+'s revenue requirement. There would be no trapped or unrecovered costs and, as a result. Energy+ would be made whole.

Q. IF STANDBY DISTRIBUTION SERVICE IS PRICED SEPARATELY FROM SUPPLEMENTARY DISTRIBUTION SERVICE, SHOULD ANY OTHER MAKE-WHOLE ADJUSTMENT BE MADE?

A. Yes. Assuming that Standby Distribution service is separately priced, it would be appropriate to account for the incremental revenues in determining the revenues that need to be recovered from the rates for Supplementary distribution service. This would ensure that Energy+'s customers are kept whole.

Capacity Reservation

Q. WHAT CAPACITY DOES ENERGY+ PURPORTEDLY RESERVE FOR TMMC'S LDG?

A. As previously stated, Energy+ asserts that it must have infrastructure in place at all times in order to provide the Contract Demand at any time. However, the Energy+ infrastructure that serves TMMC consists of two 27.6 kV feeders. These feeders have more than enough capacity to serve TMMC's gross load, which, prior to placing its LDG in operation, was as high as [redacted] MW. Under my recommended Large Use rate design, the cost of these feeders are directly assigned and would be recovered in the Primary Substation Volumetric Rate applicable to TMMC. Thus, Energy+ would not incur any incremental primary distribution costs to serve TMMC.

Q. DOESN'T ENERGY+ ALSO HAVE TO RESERVE [redacted] MW OF CAPACITY IN THE PRESTON TS TO SERVE TMMC'S STANDBY NEEDS?

A. No. This statement assumes that both TMMC generators sustain simultaneous forced outages and that the impact of the simultaneous forced outage is a [redacted] MW 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 TMMC's maximum load was 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 23, column 3). This occurred during a rare simultaneous outage of both generators at 8 am on Wednesday, November 8, 2017. When this simultaneous outage occurred, however, TMMC's maximum demand was [redacted] MW. Energy+'s system demand in that hour was [redacted] MW. This is only 70% of Energy+'s 2017 system peak.[25]

Q. HOW MUCH CAPACITY DID ENERGY+ HAVE TO RESERVE ON THE PRESTON TS PRIOR TO WHEN TMMC ADDED ITS LDG FACILITY?

A. Energy+ would have had to reserve at least [redacted] MW to accommodate TMMC's maximum demand prior to installing its LDG facility. This is nearly 10 MW higher than TMMC's maximum net peak demand in 2017.

Q. HAS ENERGY+ RECOGNIZED THE REDUCTION IN THE CAPACITY RESERVATION TO SERVE TMMC IN DETERMINING A STANDBY CHARGE?

A. No. Energy+ has provided no evidence that it considered the avoided costs resulting from the lower capacity reservation in designing its proposed Standby Distribution Volumetric Rates.

Q. 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.

Q. SHOULD THE BOARD PLACE ANY WEIGHT ON ENERGY+'S STATEMENT ABOUT RESETTING THE CONTRACTED CAPACITY RESERVE VALUE?

A. No.

[25] Derived from information provided in Energy+'s Response to TMMC-IR-14, Question 1.

Wrong Price Signals

Q. 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.

Q. HAS THE BOARD RECOGNIZED THE BENEFITS OF SHIFTING LOAD TO OFF-PEAK HOURS, EVEN FOR A DISTRIBUTOR?

A. Yes. The benefits of shifting load to off-peak hours were articulated in a 2015 OEB Staff discussion paper, which stated:

> While the size of system investment required is driven by the peak demand, customers also consume power at other "off-peak" times. Considered from the economic standpoint, off-peak demand is a co-product of the primary product and can be 'sold' at reduced prices as an additional source of revenue while peak capacity draws the primary revenue. Lower off-peak prices will encourage customers to make better use of existing distribution system assets and reduce the need for new capacity expansion.[26]

[26] EB-2015-0043, Staff Discussion Paper, *Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interests of Customers and Distributors* at 6 (Mar. 31, 2016).

Developing a Cost-Based Rate for Standby Distribution Service

February 15, 2019

Standby Distribution Service

Applicable to Customers Who Own Load Displacement Generation (LDG) That is Located Behind the Customer's Meter

The Additional Delivery Service is Required When

- A Customer's LDG Sustains an Outage, AND
- There is a Net Increase in the Customer's Peak Demand As a Result of the Outage

J. POLLOCK INCORPORATED

Standby Distribution Service
Cost Basis

Types Of Distribution Facilities

- Shared Facilities are the "Highway"
- Local Facilities are the "Driveway"

Shared Distribution Facilities

- Provide Distribution Service to all Customers (*i.e.*, Bulk Distribution) or Multiple Customers
- CP or NCP Allocation

Local Distribution Facilities

- Provide Distribution Service To Specific Customers (*i.e.*, Primary & Secondary Overhead Lines & Conductors, Poles, Towers, & Fixtures, Underground Conduit, & Underground Conductors)
- Directly Assigned or NCP Allocation

Allocation of Shared Distribution Costs

Outages Rarely Occur Coincident With a System Peak

- Forced Outages are Random, Nonrecurring Events
- Scheduled Outages can be Planned, Sometimes Well in Advance (Controlled Diversity)

Thus, the Recovery of Shared Distribution Costs Should Recognize Diversity

That is, the More Standby Distribution Service is Used, the More Likely an Outage Will Coincide With a System Peak

- & the Higher the Cost to Serve

Allocation of Local Distribution Costs

Local Facilities are Electrically Closer to the Customer

- Less Diversity (Not Zero)
- Sized to Meet the Maximum Expected Demand
- Anytime

Local Distribution Costs Are Incurred Regardless of the Amount of Standby Distribution Service

Thus, the Recovery of Local Distribution Costs Should Recognize Expected Max Peak Demand

Cost-Based Rate For Distribution Standby Service

Contract Volumetric Rate

Local Distribution Costs

Standby Contract Demand
- Customer Determined

Annual Fixed Costs
- Not Affected By the Amount of Service Actually Provided

Daily Volumetric Rate

Bulk Distribution Costs

Daily Demand
- Weekdays
- On-Peak Period

Costs Vary With the Amount of Service
- Higher Coincidence
- Higher Costs

Example of a Distribution Standby Rate Design For a Hypothetical Customer Class

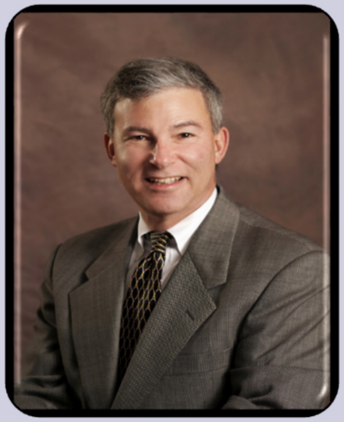
Description	Supplementary Service	Standby Service	
		Shared Costs	Local Costs
1. Target Rate Design Revenues	$1,000,000		
2. Less: Service Charge Revenues	$100,000		
3. Equals: Volumetric Rate Revenues	$900,000	$200,000	$700,000
4. Billing Determinants (kW)	300,000		300,000
5. Volumetric Rate ($/kW)	**$3.00**		
6. Contract Volumetric Rate ($/kW)			**$2.33**
7. System Bulk Distribution Costs	Assumption	$1,650,000	
8. System 12CP Demand (kW)		2,710,000	
9. Unit Cost ($/kW)	L.7 ÷ L.8	$0.609	
10. Loss Factor	Assumption	10%	
11. Unit Cost at Delivery Voltage	L.9 x (1+L.10)	$0.670	
12. No. of Weekdays Per Billing Month		20.9	
13. Daily Volumetric Rate ($/kW)	L.11 ÷ L.12	**$0.032**	

J. POLLOCK INCORPORATED

Billing Example For a Hypothetical Customer

Description	No Outage	7-Day Outage	1 Month Outage
Supplementary Power Demand (kW)	50	50	50
Standby Contract Demand (kW)	100	100	100
On-Peak Monthly Peak Demand (kW)	50	150	150
Maximum Daily Demand (kW)	N/A	100	100
Volumetric Rate at $3.00/kW	$150.00	$150.00	$150.00
Contract Volumetric Rate at $2.33/kW	$233.00	$233.00	$233.00
Daily Volumetric Rate at $0.032/kW-Day	$0	$22.40	$67.00
Total Volumetric Charges	$383.00	$405.40	$450.00

Questions?



Jeffry Pollock
12647 Olive Blvd, Suite 585
St. Louis, MO 63141
☎: 314-878-5814
💻: 314-878-7339
✆: 314-960-3901
✉jcp@jpollockinc.com

FORM A

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.

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Jeffry Pollock. I work in St. Louis, Missouri.

2. I have been engaged by or on behalf of Toyota Motor Manufacturing Canada Inc. to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: 2/15, 2019.

Jeffry Pollock

Signature

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0028

Sheet O1 Revenue to Cost Summary Worksheet - Two Large Use Classes/Direct Assignment

Class Revenue, Cost Analysis, and Return on Rate

			1	2	3	5	6	7	8	9	10
Line	Description	Total	Residential	GS <50	GS> 50- 999 kW	GS> 1,000 - 4,999 kW	Large Use 1	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor Hydro One - CND
1	Distribution Revenue at Existing Rates	$33,454,352	$17,528,595	$4,131,617	$7,466,138	$2,140,493	$259,214	$671,811	$14,573	$64,042	$50,527
2	Miscellaneous Revenue (mi)	$2,022,079	$1,357,570	$222,389	$245,250	$91,016	$9,890	$56,446	$1,326	$4,532	$634
		Miscellaneous Revenue Input equals Output									
3	**Total Revenue at Existing Rates**	$35,476,431	**$18,886,164**	**$4,354,006**	**$7,711,388**	**$2,231,509**	**$269,104**	**$728,257**	**$15,899**	**$68,574**	**$51,160**
4	Factor required to recover deficiency (1 + D)	1.0261									
5	Distribution Revenue at Status Quo Rates	$34,327,788	$17,986,236	$4,239,487	$7,661,066	$2,196,378	$265,982	$689,351	$14,953	$65,714	$51,846
6	Miscellaneous Revenue (mi)	$2,022,079	$1,357,570	$222,389	$245,250	$91,016	$9,890	$56,446	$1,326	$4,532	$634
7	**Total Revenue at Status Quo Rates**	$36,349,867	**$19,343,806**	**$4,461,876**	**$7,906,317**	**$2,287,394**	**$275,871**	**$745,797**	**$16,279**	**$70,246**	**$52,479**
	Expenses										
8	Distribution Costs (di)	$4,860,260	$2,894,330	$496,785	$924,005	$368,553	$37,318	$89,526	$4,097	$13,539	$0
9	Customer Related Costs (cu)	$4,893,912	$3,864,514	$637,554	$290,384	$88,328	$3,679	$1,531	$181	$1,388	$2,419
10	General and Administration (ad)	$8,577,377	$5,835,887	$983,938	$1,078,443	$404,663	$36,580	$82,040	$3,850	$13,384	$6,040
11	Depreciation and Amortization (dep)	$6,376,711	$3,704,003	$787,999	$1,234,577	$426,165	$44,450	$102,838	$5,032	$16,591	$2,921
12	PILs (INPUT)	$768,693	$437,563	$85,014	$155,976	$56,051	$5,672	$14,651	$679	$2,238	$675
13	Interest	$4,420,641	$2,516,359	$488,905	$896,993	$322,342	$32,617	$84,255	$3,904	$12,870	$3,882
14	**Total Expenses**	$29,897,594	**$19,252,655**	**$3,480,197**	**$4,580,378**	**$1,666,102**	**$160,315**	**$374,841**	**$17,742**	**$60,010**	**$15,936**
15	**Direct Allocation**	$245,744	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$22,095**
16	Allocated Net Income (NI)	$6,206,530	$3,532,940	$686,418	$1,259,368	$452,565	$45,793	$118,293	$5,481	$18,069	$5,450
17	**Revenue Requirement (includes NI)**	$36,349,867	$22,785,595	$4,166,614	$5,839,746	$2,118,667	$206,108	$493,134	$23,223	$78,079	$43,481
	Rate Base Calculation										
	Net Assets										
18	Distribution Plant - Gross	$197,935,948	$113,846,650	$22,412,628	$39,822,618	$14,301,708	$1,473,960	$3,760,154	$172,867	$569,420	$21,826
19	General Plant - Gross	$15,515,903	$8,867,957	$1,720,649	$3,118,730	$1,112,648	$115,634	$297,680	$13,780	$45,279	$14,580
20	Accumulated Depreciation	($25,245,338)	($14,456,225)	($3,130,320)	($4,913,552)	($1,856,299)	($177,242)	($423,008)	($18,397)	($62,019)	($15,707)
21	Capital Contribution	($31,975,089)	($18,800,132)	($3,623,027)	($6,157,115)	($2,108,502)	($252,518)	($639,182)	($29,448)	($95,175)	($3,739)
22	**Total Net Plant**	$156,231,424	**$89,458,250**	**$17,379,930**	**$31,870,681**	**$11,449,556**	**$1,159,833**	**$2,995,644**	**$138,802**	**$457,505**	**$16,960**
23	**Directly Allocated Net Fixed Assets**	$898,672	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$121,453**
24	**Working Capital**	$16,695,208	**$5,237,222.63**	**$1,953,882**	**$4,710,066**	**$2,183,424**	**$293,927**	**$48,068**	**$1,783**	**$23,128**	**$117,405**
25	**Total Rate Base**	$173,825,304	**$94,695,473**	**$19,333,812**	**$36,580,746**	**$13,632,979**	**$1,453,761**	**$3,043,711**	**$140,584**	**$480,633**	**$255,819**
26	**REVENUE TO EXPENSES STATUS QUO%**	100.00%	**84.89%**	**107.09%**	**135.39%**	**107.96%**	**133.85%**	**151.24%**	**70.10%**	**89.97%**	120.69%

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0028

Sheet O1 Revenue to Cost Summary Worksheet - Two Large Use Classes/Direct Assignment

Class Revenue, Cost Analysis, and Return on Rate

Line	Description	Total	12 Embedded Distributor Waterloo North Hydro - CND	13 Embedded Distributor Hydro One 1 - BCP	14 Embedded Distributor Brantford Power - BCP	15 Embedded Distributor Hydro One 2 - BCP	16 Large Use 2
1	Distribution Revenue at Existing Rates	$33,454,352	$221,287	$115,168	$5,388	$4,655	$780,844
2	Miscellaneous Revenue (mi)	$2,022,079	$1,666	$351	$201	$224	$30,585
		Mis					
3	**Total Revenue at Existing Rates**	$35,476,431	**$222,954**	**$115,519**	**$5,589**	**$4,879**	**$811,429**
4	Factor required to recover deficiency (1 + D)	1.0261					
5	Distribution Revenue at Status Quo Rates	$34,327,788	$227,064	$118,174	$5,529	$4,777	$801,231
6	Miscellaneous Revenue (mi)	$2,022,079	$1,666	$351	$201	$224	$30,585
7	**Total Revenue at Status Quo Rates**	$36,349,867	**$228,731**	**$118,525**	**$5,730**	**$5,000**	**$831,816**
	Expenses						
8	Distribution Costs (di)	$4,860,260	$0	$0	$0	$0	$32,108
9	Customer Related Costs (cu)	$4,893,912	$405	$405	$705	$1,620	$799
10	General and Administration (ad)	$8,577,377	$17,599	$3,502	$1,820	$1,358	$108,274
11	Depreciation and Amortization (dep)	$6,376,711	$4,561	$836	$602	$0	$46,137
12	PILs (INPUT)	$768,693	$2,682	$491	$199	$0	$6,803
13	Interest	$4,420,641	$15,424	$2,826	$1,142	$0	$39,120
14	**Total Expenses**	$29,897,594	**$40,672**	**$8,060**	**$4,468**	**$2,978**	**$233,241**
15	**Direct Allocation**	$245,744	**$95,569**	**$17,510**	**$6,787**	**$0**	**$103,784**
16	Allocated Net Income (NI)	$6,206,530	$21,656	$3,968	$1,604	$0	$54,925
17	**Revenue Requirement (includes NI)**	$36,349,867	$157,897	$29,537	$12,859	$2,978	$391,949
	Rate Base Calculation						
	Net Assets						
18	Distribution Plant - Gross	$197,935,948	$0	$0	$3,252	$0	$1,550,865
19	General Plant - Gross	$15,515,903	$57,785	$10,587	$4,285	$0	$136,306
20	Accumulated Depreciation	($25,245,338)	($33,215)	($6,085)	($3,555)	$0	($149,713)
21	Capital Contribution	($31,975,089)	$0	$0	($557)	$0	($265,694)
22	**Total Net Plant**	$156,231,424	**$24,571**	**$4,502**	**$3,426**	**$0**	**$1,271,765**
23	**Directly Allocated Net Fixed Assets**	$898,672	**$525,336**	**$96,250**	**$37,305**	**$0**	**$118,327**
24	**Working Capital**	$16,695,208	**$539,518**	**$113,175**	**$3,505**	**$399,953**	**$1,070,152**
25	**Total Rate Base**	$173,825,304	**$1,089,425**	**$213,927**	**$44,235**	**$399,953**	**$2,460,244**
26	**REVENUE TO EXPENSES STATUS QUO%**	100.00%	144.86%	401.27%	44.56%	167.90%	212.23%

ENERGY+, Inc.
4NCP and 12CP Allocation Factors With and Without TMMC

		With TMMC				Without TMMC			
		4NCP		12CP		4NCP		12CP	
Line	Customer Class	Amount	Percent	Amount	Percent	Amount	Percent	Amount	Percent
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	290,249	28.95%	919,944	32.99%	290,249	31.49%	919,944	35.62%
2	GS <50	102,988	10.27%	283,153	10.16%	102,988	11.17%	283,153	10.96%
3	GS> 50- 999 kW	331,610	33.08%	869,313	31.18%	331,610	35.98%	869,313	33.66%
4	GS> 1,000 - 4,999 kW	172,359	17.19%	446,445	16.01%	172,359	18.70%	446,445	17.29%
5	Large Use 1	22,131	2.21%	53,994	1.94%	22,131	2.40%	53,994	2.09%
6	Street Light	2,019	0.20%	6,541	0.23%	2,019	0.22%	6,541	0.25%
7	Sentinel	0	0.00%	219	0.01%	0	0.00%	219	0.01%
8	Unmetered Scattered Load	298	0.03%	3,107	0.11%	298	0.03%	3,107	0.12%
9	TMMC	80,855	8.07%	205,580	7.37%	0	0.00%	0	0.00%
10	Total	1,002,509	100.00%	2,788,296	100.00%	921,654	100.00%	2,582,715	100.00%

Source: Energy+ Response to TCQ TMMC IR-2(a).

ENERGY+, Inc.

TMMC Recommended Supplementary Distribution Service Rate Design

Line	Description	Cost	Billing Units	Rate	Reference
		(1)	(2)	(3)	(4)
1	**Total Revenue Requirement**	$391,949			Schedule JP-11, Row 40
2	Revenue-to-Cost Ratio	1.15			Assumption
3	Target Revenue	$450,741			Line 1 x Line 2
4	Less: Other Revenues	$30,585			Schedule JP-11, Row 2
5	Target Rate Design Revenue	$420,157			Line 3 - Line 4
6	Service Charge	$107,713	12 Bills	$8,976.07	
7	Revenues to be Recovered In Distribution Volumetric Rate	$312,444			Line 5 - Line 6
8	**Shared Facilities Cost**	$164,161	[redacted] kW	[redacted]	Line 14
9	**Local Facilities Cost**	$148,283	kW		Line 15
10	**Distribution Volumetric Rate**	$277,648			Line 8 + Line 9

Line	Description	Cost	
	Revenue Requirement By Function:		
11	Target Rate Design Revenue	$420,157	
12	Less Service Charge Revenue	$107,713	
13	Demand-Related Revenue Required	$312,444	
14	Shared Facilities (Primary Poles)	$164,161	JP-11, Sht O2.2
15	Local Facilities	$148,283	

ENERGY+, Inc.

TMMC Class Billing Demand

(Amounts in kW)

Line	Description	Amount	Reference
		(1)	(2)
1	Energy+ Projection	300,496	Energy+ Response to TCQ TMMC IR-2(a)
2	Less: Energy+ LDG Adjustment	[redacted]	Schedule JP-1
3	Supplementary Billing Demand		Line 1 - Line 2
4	Standby Contract Demand	82,800	6,900 kW per Month
5	Total Primary Substation - Feeder Billing Demand	[redacted]	Line 3 + Line 4

ENERGY+, Inc.

TMMC Recommended Standby Distribution Service Rate Design

Line	Description	Rate	Reference
		(1)	(2)
1	**Contract Volumetric Rate (Local Facilities)**	[redacted]	Schedule JP-13, pg. 1, Line 9
	Daily Volumetric Rate:		
2	Shared Facilities Unit Cost	[redacted]	Schedule JP-13, pg. 1, Line 8
3	No. of Weekdays Per Billing Month	20.9	
4	**Daily Volumetric Rate**	[redacted]	Line 2 ÷ Line 3
5	**Monthly Maximum Standby Volumetric Rate**	[redacted]	Line 1 + Line 2

ENERGY+, Inc.
Recommended Standby Distribution Service Rate Design
Applicable to the GS 50 - 999 kW Customer Class

Line	Description	Rate	Reference
		(1)	(2)
	Contract Volumetric Rate:		
1	Local Distribution Costs	$4,359,649	Schedule JP-15, pg. 2
2	Billing Demand	1,568,556	Schedule JP-11, Sht. I6.1
3	**Contract Volumetric Rate**	$2.779	Line 1 ÷ Line 2
	Daily Volumetric Rate:		
4	Shared Distribution Costs	$1,382,087	Schedule JP-15, pg. 3
5	Sum of 12CP Demand at Source	2,528,721	Schedule JP-11, Sht. I8
6	Unit Cost	$0.547	Line 4 ÷ Line 5
7	Distribution Secondary Loss Factor	2.61%	Application Exhibit 8, Table 8-16
8	Unit Cost at Secondary Voltage	$0.561	Line 6 x (1 + Line 7)
9	No. of Weekdays Per Billing Month	20.9	
10	**Daily Volumetric Rate**	$0.027	Line 8 ÷ Line 9

ENERGY+, Inc.

Local Distribution Costs
GS 50 - 999 kW Customer Class

Line	Description	Amount
		(1)
1	Distribution Costs	$799,646
2	General & Administrative	$703,173
3	Depreciation & Amortization	$1,009,046
4	PILS	$135,822
5	Interest Expense	$781,090
6	Total Expenses	$3,428,777
7	Allocated Net Income	$1,096,642
8	Total Revenue Requirement	$4,525,419
8	Revenue-to-Cost Ratio	1.00
9	Miscellaneous Revenue	$165,770
10	Revenue Requirement	$4,359,649

ENERGY+, Inc.

Shared Distribution Costs Based on
The Settlement Revenue Requirement

Line	Description	Amount
		(1)
1	Distribution Costs	$313,513
2	General & Administrative	$275,689
3	Depreciation & Amortization	$171,804
4	PILS	$46,278
5	Interest Expense	$266,139
6	Total Expenses	$1,073,424
7	Allocated Net Income	$373,656
8	Miscellaneous Revenue	$64,993
9	Revenue Requirement	$1,382,087

ENERGY+, Inc.
Revenues From TMMC Recommended
Standby Distributiion Service Rate

Line	Description	Rate	Billing Units		Revenues
		(1)	(2)		(3)
1	**Contract Volumetric Rate**	[redacted]	82,800	kW	[redacted]
2	**Daily Volumetric Rate**	$0.029	[redacted]	kW	
3	**Total Standby Service Revenues**				

Col. References:
(1) Schedule JP-14, page 1.
(2) Assumed Standby Contract Demand; Schedule JP-7 Revised.
(3) Col (1) x Col (2).