**Ontario Energy Board**
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

**Commission de l'énergie de l'Ontario**
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

**BY E-MAIL**

March 29, 2019

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

Dear Ms. Walli:

**Re: Energy+ Inc. (Energy+)**
**2019 Cost of Service Application**
**OEB File Number EB-2018-0028**
**OEB Staff Submission**

Please find attached OEB staff's submission for Energy+'s 2019 Cost of Service Application.

Energy+ and all intervenors have been copied on this filing.

Yours truly,

*Original Signed By*

Shuo Zhang

Project Advisor, Major Applications

Encl.

# 2019 COST OF SERVICE APPLICATION

# ENERGY+ INC.

# EB-2018-0028

# OEB STAFF SUBMISSION

# MARCH 29, 2019

## INTRODUCTION

Energy+ Inc. (Energy+) filed a complete application with the Ontario Energy Board (OEB) on April 30, 2018 seeking approval for changes to the rates that Energy+ charges for electricity distribution, to be effective January 1, 2019. The OEB issued an approved issues list for this proceeding on October 31, 2018.

A settlement conference was held from November 7, 2018 to November 9, 2018 and teleconferences were held until December 12, 2018. Energy+ filed a partial settlement proposal with the OEB on December 12, 2018. The parties to the settlement proposal are Energy+ and the following approved intervenors[1] in the proceeding: Consumers Council of Canada (CCC), Hydro One Networks Inc. (Hydro One), School Energy Coalition (SEC), Toyota Motor Manufacturing Canada Inc. (TMMC), and Vulnerable Energy Consumers Coalition (VECC) (the Parties). A technical conference was held on January 23, 2019 followed by an oral hearing on March 7-8, 2019. Energy+ filed its argument-in-chief on March 15, 2019.

For the purpose of organizing this submission, OEB staff follows Energy+'s argument-in-chief to address each of the unsettled issues as follows:

- I. Issue 1.1 Advanced Capital Module (ACM)
- II. Issue 3.2 Cost Allocation
    - a. Large Use Class Cost Allocation
    - b. Embedded Distributor Class Revenue to Cost Ratio
- III. Issues 3.3 & 3.4 Rate Design
    - a. Large Use Class Fixed Charge
    - b. Rate Mitigation
- IV. Issues 3.5 & 3.6 Retail Transmission Service Rates (RTSRs) & Low Voltage (LV) Rates, including gross load billing of RTSRs
    - a. Retail Transmission Service Rates
    - b. Gross Load Billing
    - c. Low Voltage Rates
- V. Issue 3.7 Standby Charge
- VI. Issue 4.2 Group 2 Deferral and Variance Accounts (DVAs)
    - a. Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)

[1] Brantford Power Inc. (BPI) is also an approved intervenor in the proceeding. BPI did not participate in the settlement conference.

b. Group 2 Deferral and Variance Accounts

VII. Issue 3.1 Load Forecast

## I. Issue 1.1 Advanced Capital Module

***Background***

Energy+ is currently operating out of three facilities: Bishop Street, Thompson Drive, and Dundas Street buildings. In the Cambridge and North Dumfries (CND) service territory, the Bishop Street facility is a head office and operation center owned by Energy+, and the Thompson Drive facility is a leased administrative building. The Dundas Street facility is an administrative and operational building that serves the Brant County Power (BCP) service territory.

Energy+ proposes a facilities plan that consists of one administrative office building (Southworks) and two operation centers (Garden Avenue and Bishop Street). With the proposed facilities plan, the leased space at the Thompson Drive facility would no longer be required, and Energy+ has sold the land and building at the Dundas Street facility. Energy+ plans to renovate an existing heritage building in downtown Cambridge, known as Southworks, and convert it into suitable office space to centralize all administrative departments. Energy+ proposes to relocate all administrative employees to this new office building. Energy+ proposes to modernize its existing building at Bishop Street in Cambridge into an operation center to serve customers in the CND service territory. The proposed Garden Avenue facility would be constructed by Brantford Power Inc. (BPI) and Energy+ plans to share space at this new facility as an operation center to serve customers in the BCP service territory. As noted in the settlement proposal, Energy+ proposes to submit an Incremental Capital Module (ICM) request at the same time with BPI's ICM request for the Garden Avenue facility. The ICM request is now expected to be in both Energy+'s and BPI's 2020 rates applications.[2] The Bishop Street and Garden Avenue facilities are part of Energy+'s overall facilities plan, but are not items that need to be determined in this proceeding.

The ACM request for the Southworks facility is an unsettled issue in the current application. The overall budget for this facility is estimated at $8.1 million, consisting of $6.7 million of construction costs and $1.3 million of soft costs (e.g.

[2] Settlement Proposal, December 12, 2018, page 17.

professional fees, building permits, contingency costs, etc.).[3] The construction cost is based on a Class C estimate with a +/- 20% uncertainty. Energy+ plans to complete the proposed renovations in 2021 and expects the Southworks facility to be ready for occupancy in 2022.[4]

The OEB's ACM Report[5] provides an electricity distributor with an approach to identify and pre-test, as part of the rebasing application, qualifying discrete capital projects that are scheduled to go into service during the subsequent Price Cap incentive rate-setting (IR) term, and documented in a distributor's Distribution System Plan. As described in section 2.2.2.3 of the Filing Requirements[6], the nature and need for the ACM project will be determined in the cost of service application. The timing and actual amount of rate riders used to recover the costs of an ACM project will be determined in the subsequent Price Cap IR application for the year in which the project comes into service.

In order to qualify for ACM funding, a request must satisfy the eligibility criteria of (i) materiality, (ii) need and (iii) prudence, as set out in section 4.1.5 of the ACM Report. Changes to the materiality threshold were made in the Supplemental ACM Report.[7]

The ACM Report explains materiality as follows[8]:

> A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the OEB-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
>
> Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of

---

[3] SEC TCQ 1.

[4] Oral Hearing Transcript, March 7, 2019, page 55, line 2.

[5] EB-2014-0219, *Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module,* September 18, 2014 (ACM Report).

[6] Ontario Energy Board *Filing Requirements For Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications- Chapter 2,* (Filing Requirements)*, section 2.2.2.3.*

[7] EB-2014-0219, *Report of the Board on* New Policy Options for the Funding of Capital Investments: Supplemental Report, January 22, 2016 (Supplemental ACM Report).

[8] ACM Report, *op. cit*., page 17.

project expenditure over and above the OEB-defined threshold calculation is expected to be absorbed within the total capital budget.

The ACM Report describes need as follows:

> The distributor must pass the Means Test (as defined in the ACM Report).
>
> Amounts must be based on discrete projects, and should be directly related to the claimed driver.
>
> The amounts must be clearly outside of the base upon which the rates were derived.

The ACM Report further describes prudence as follows:

> The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

***OEB Staff Submission***

OEB staff will address each criteria listed in the ACM Report with respect to the proposed Southworks facility project.

<u>Materiality</u>

For an ACM request, as part of the cost of service application, distributors must provide a preliminary estimate of the materiality threshold value for the subject year in which the proposed project is planned to enter into service.[9]

The Supplementary ACM Report set out the ACM materiality threshold formula.[10] Energy+ used a price cap index of 1.2%, which was based on an inflation factor of 1.5% less a productivity factor of 0% and a stretch factor of 0.3%. Using the OEB-defined formula, Energy+ calculated its preliminary materiality threshold to be $10,029,912. The OEB-defined formula indicates that Energy+ would be able to finance capital expenditures of this amount through its existing rates, including growth in demand and a 10% dead band. The maximum amount available to Energy+ for an ACM is $12,041,088 and is determined as the difference between

[9] *Ibid.* page 14.
[10] Supplemental ACM Report, *op. cit*., Appendix B.

the total 2022 capital budget ($22,071,000) and the materiality threshold ($10,029,912).[11]

OEB staff has no concern with Energy+'s calculation of the materiality threshold and submits that the proposed capital expenditure of $8.1 million for the Southworks facility falls within the eligible incremental capital envelope available to Energy+. OEB staff submits that the materiality criteria is satisfied at this time.

OEB staff notes that the final assessment of whether or not the project fits within the maximum allowable capital amount will be made by the OEB at the time that Energy+ files its Price Cap IR application in 2022. If the costs of the project exceed the total available envelope for the subject year, the amount allowed for recovery will be limited to the maximum allowable capital amount.[12]

In addition, the OEB has established a project-specific materiality threshold[13] by comparing the proposed ACM project relative to the total capital budget, as identified in the Toronto Hydro decision.[14] By adopting this approach, OEB staff submits that the Southworks facility is material as the requested cost represents about 37% of the 2022 total capital budget.

<u>Need</u>

*Means Test*

OEB staff notes that, any approvals provided for an ACM in a cost of service application will be subject to the distributor passing the means test in order to receive its funding during the subsequent Price Cap IR term.[15] The means test requires that the most recent actual regulated return not exceed by more than 300 basis points above the deemed return on equity embedded in the distributor's rates. If the utility is overearning by more than 300 basis points on a regulated basis, the funding for an incremental capital project will not be allowed. As such, if the OEB approves the Southworks facility in this application, Energy+ shall apply the means test at the time of the applicable Price Cap IR application, in which the recovery of the project costs through rate riders would commence.

[11] Argument-In-Chief, page 7, Table 1 and 2.

[12] ACM Report, *op. cit.*, section 4.1.2.

[13] *Ibid*., page 17.

[14] EB-2012-0064, Toronto Hydro IRM Application*,* Partial Decision and Order, April 2, 2013.

[15] ACM Report, page 15.

*Discrete Project*

OEB staff agrees with Energy+ that the proposed Southworks facility is a discrete and distinct project unrelated to any recurring annual capital projects.

OEB staff further submits that the need for the Southworks facility has been supported by evidence filed by Energy+ including:

- The existing facility at Bishop Street has passed its intended 25 year lifespan. To accommodate additional employees, workstations were built in areas of the building that were not intended for this type of use, such as hallways.[16]
- The need for a consolidated location for all administrative staff after the acquisition of Brant County Power Inc. in 2014 to ensure more efficient processes between departments.[17]
- The space needs analysis conducted in 2014 for the former Cambridge and North Dumfries Hydro Inc. recommended 102,762[18] square feet for all administrative and operations space at that time. In comparison, in OEB staff's view, the proposed 88,243 square feet space across the three buildings is reasonable.

<u>Prudence</u>

Energy+ stated that it reviewed and assessed six options to meet its space needs in the CND service territory and determined that the preferred option is the most cost-effective one.[19] The alternative options reviewed by Energy+ included renovating/rebuilding the existing Bishop Street facility, purchasing/renovating alternative facilities, and construction of new facilities. Cost estimates for the alternatives are in the range of $28 million to $32 million.

Energy+ also conducted benchmarking analysis that compared cost and utilization of its proposed facilities plan against other distributors. In response to a technical conference question, Energy+ provided the following table for comparison:

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[16] Exhibit 2, Appendix 2-1, pp. 1032-1035.
[17] *Ibid.*
[18] Exhibit 2, Appendix 2-1, Appendix B Facilities Business Plan, Section 3, page 1087 of 1497.
[19] Argument-In-Chief, pp. 10-13.

**Table 1. Cost and Utilization Comparison to Other Distributors**[20]

| LDC | Energy+ (Southworks, Bishop Street & Garden Avenue Combined) | Energy+ (Southworks) | Energy+ (Garden Ave) | Energy+ (Bishop St.) | Waterloo North Hydro Inc | InnPower | Milton Hydro Distribution Inc | PUC Distribution Inc. |
|---|---|---|---|---|---|---|---|---|
| OEB Docket | EB-2018-0028 | | | | EB-2015-0108<br>EB-2010-0144 | EB-2014-0086 | EB-2015-0089 | EB- 2012-0162 |
| Year of Occupancy | 2020/2022/2024 | 2022 | 2020 | 2024 | 2011 | 2015 | 2015 | 2012 |
| Functions | Administration & Operations | Administration | Operations | Operations | Administration & Operations | Administration & Operations | Administration & Operations | Administration & Operations |
| Type of Project | Purchase/<br>Refurbish | Purchase/<br>Refurbish | Purchase | Refurbish | Custom Build | Custom Build | Purchase/<br>Refurbish | New Build |
| Capital Cost | $14,500,000 | $8,100,000 | $4,400,000 | $2,000,000 | $26,682,000 | $10,896,704 | $12,524,798 | $23,000,000 |
| | | | | | | | | |
| Class of Estimate | | Class C | Class D | Not Applicable | | | | |
| Highest Class Estimate % | | +20% | +30% | Assume 30% - Similar to Class D | | | | |
| | | | | | | | | |
| Square Footage | 88,243 | 21,892 | 13,251 | 53,100 | 105,000 | 36,172 | 91,872 | 110,382 |
| FTEs | 131 | 67 | 13 | 51 | 125 | 41 | 61.5 | 87 |
| Square Foot per FTE | 674 | 327 | 1,019 | 1,041 | 840 | 882 | 1,494 | 1,269 |
| Capital Cost per FTE | $110,687 | $120,896 | $338,462 | $39,216 | $213,456 | $265,773 | $203,655 | $264,368 |
| Capital Cost/Square Foot | $164.32 | $370.00 | $332.05 | $37.66 | $254.11 | $285.79 | $136.33 | $208.37 |

[20] SEC Technical Conference Question 5, January 22, 2019.

Table 1 shows the benchmarking comparisons of Energy+'s comprehensive facilities plan to other distributors as well as the comparisons for each facility. Compared to other distributors, OEB staff notes that Energy+'s planned-for space is not excessive as it results in the lowest square foot per full time equivalent (FTE). With respect to cost, Energy+ plans to complete all three facilities at a cost of $164.32 per square foot, which is the second lowest among all comparators.

OEB staff notes that when comparing the Southworks facility alone to combined operations and administration facilities utilized by other distributors, it has the highest capital cost per square foot at $370.00. OEB staff compared two other administrative office buildings approved in OEB decisions with the Southworks facility in Table 2 below.

**Table 2. Comparison of Southworks Facility to Administrative Office Buildings for Other Electricity Distributors**

| LDC | Energy+ (Southworks) | PowerStream (now part of Alectra)[21] | Enersource (now part of Alectra)[22] |
|---|---|---|---|
| OEB Docket | EB-2018-0028 | EB-2008-0244 | EB-2012-0033 |
| Functions | Admin | Admin | Admin |
| In-service Year | 2022 | 2008 | 2012 |
| Total Cost | $8,100,000 | $27,700,000 | $18,000,000 |
| Total Sq. Ft. | 21,892 | 92,000 | 79,000 |
| FTEs | 67 | 250 | 150 |
| Sq. Ft./FTE | 327 | 368 | 527 |
| Cost/FTE | $120,896 | $110,800 | $120,000 |
| Cost/Sq. Ft. | $370 | $301 | $228 |

[21] EB-2008-0244, Exhibit B1, Tab 5, Schedule 1 (page 2) and Schedule 3 (page 12 of 18).
[22] EB-2012-0033, Decision and Order, December 13, 2012, pp. 13-18.

OEB staff notes the following limitations in this comparison:

- The presence of inflation in the construction sector since 2008 and 2012 was not recognized.
- The cost of land/building can vary significantly depending on the location and the market conditions at the time the transaction was done.

However, OEB staff agrees with Energy+ that building administrative space is generally more costly than building operations space in terms of cost per square foot.[23] OEB staff submits that the proposed capital cost per square foot for the Southworks facility is comparable to similar investments that have been approved by the OEB.

Based on the assessment of materiality, need and prudency, OEB staff submits that the Southworks facility meets the requirements of an ACM as set out in the ACM Report and the ACM Supplemental Report. OEB staff notes that in accordance with the ACM Report, the review and approval process of the actual costs and the establishment of the rate riders intended to recover approved project costs will be part of the subsequent Price Cap IR term.[24]

Although the details and need for a project, which has received ACM approval in a cost of service application, would not be re-examined in the subsequent Price Cap IR application, the ACM Report outlines the requirement for distributors to explain and justify any changes in project costs:[25]

> In particular, if costs are 30% (or more) above what was documented in the DSP, the distributor has the option of seeking approval for the incremental costs but would typically treat the project as a new ICM and re-file the business cases and other relevant material in the applicable IR year. It is expected that the Board will include this condition as part of the ACM approval. This would provide the applicant and parties an opportunity to argue for a different (higher or lower) percentage depending on the nature of the project.
>
> If costs are less than 30% above what was documented in the DSP, the distributor should still explain the need for the increased costs, whether and how re-prioritizing of capital projects has been considered, how

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[23] Argument-In-Chief, page 16.

[24] This is consistent with the OEB's decision on Wellington North Power Inc.'s ACM request in its 2016 CoS application (EB-2015-0110,), March 31, 2016.

[25] ACM Report, *op. cit*., page 12.

> impacts on the rates and bills of the distributor's ratepayers have been taken into account and finally, whether the project is still the best option. Any changes in project scope must be clearly explained and justified.

Pursuant to the ACM Report, funding for the ACM shall not commence for any projects that are not forecasted to be in service during the subject Price Cap IR year.[26] In this case, Energy+ noted that since it will use parking space in an adjacent condo tower for its employees and visitors, the construction and occupancy dates for the Southworks facility could be pushed out six to nine months based on the construction timeline of the condo tower.[27] If the in-service date of the Southworks facility is delayed beyond 2022, Energy+ should not seek to have the rider calculated and implemented as part of its 2022 Price Cap IR application.

OEB staff also suggests that the review and approval of the final Southworks costs, now expected to be filed in Energy+'s 2022 rate application, should be informed by the OEB's decision on the Garden Avenue facility which is expected to be part of both Energy+'s and BPI's 2020 rates applications. OEB staff submits that Energy+ should prepare an updated cost and utilization comparison of Energy+'s comprehensive facilities plan (Southworks, Garden Avenue, and Bishop Street) to other distributors' facilities as part of its 2022 Price Cap IR application. This comparison would be informative to the OEB in making a final determination on the Southworks facility.

## II. Issue 3.2 Cost Allocation

### a. Large Use Class Cost Allocation

***Background***

Energy+ has two Large Use customers in its former CND service area. One of the customers, TMMC, is presently served by two feeders that are dedicated to its use, and directly connected to Hydro One's Preston Transformer Station (Preston TS).

TMMC installed an on-site generation facility consisting of two 4.6MW combined heat and power (CHP) units. It uses the steam as process heat, as well as for heating and cooling its facilities. TMMC has the capability to operate the units

[26] ACM Report, *op. cit.*, page 13.
[27] VECC-TCQ-62.

separately, and typically operates both units at full capacity while running production in the factory, and one at other times. It also uses this capability to take one plant at a time out for service during its lower load times.

The Parties disagree whether both TMMC and the other Large Use customer should be served in a single Large Use rate class, or whether each customer should be in its own rate class. The Parties also disagree whether there should be direct allocation of the costs of the assets used exclusively by TMMC and if so, whether direct allocation should be utilized for a single customer or the entire rate class. Finally, the Parties disagree with respect to whether TMMC's usage should factor into the allocation of underground conduit and bulk distribution assets.

### *Number of Large Use rate classes*

Energy+ proposes that a single Large Use rate class is appropriate, rather than two separate Large Use classes.[28] In CND's last cost of service application, its rates were approved on the basis of two customers in the Large Use rate class.[29] TMMC testified that it is sufficiently different from the other Large Use customer such that TMMC requires a separate rate class in order to properly attribute cost causation to it.[30] To identify the distinguishing characteristics of the proposed separate rate class, TMMC relies on four criteria that necessitate the need for a second rate class:[31]

- The operation of a Load Displacement Generation (LDG) facility
- Load in excess of 20 MW
- Primary substation service
- Dedicated distribution assets (with the exception of poles)

In support of a rate class dedicated to TMMC, two Ontario Local Distribution Companies (LDCs) with rate classes dedicated to Large Use customers served with dedicated feeders were referenced; EnWin Utilities Ltd. (EnWin Utilities) and Alectra Utilities Corporation (Alectra Utilities).

[28] Argument-in-Chief, page 20.
[29] EB-2013-0116.
[30] TMMC updated evidence of Jeffry Pollock filed February 15, 2019 (Updated Pollock Evidence), pp. 9-10.
[31] Updated Pollock Evidence, *op. cit.*, pp. 9-10.

EnWin Utilities has three Large Use rate classes that were created in 2002; Large Use, Large Use 3TS, and Large Use Ford Annex.

Alectra, in its rate zone serving the former customers of Horizon Utilities Corporation (Horizon), has two Large Use rate classes: Large Use (1) and Large Use (2). The Large Use (2) rate class was created in Horizon's last Custom IR[32] application prior to amalgamation. The OEB decided "that the proposal put forward by Horizon to establish a new Large Use customer class (Large Use (2)) based on having a capacity greater than 5 Megawatts and using dedicated assets, is appropriate, and reflects the principle of cost causality."[33] This subdivision of rate classes resulted in Horizon having six customers in its Large Use (1) rate class, and five customers in its Large Use (2) rate class.[34]

### *Allocation to customers or rate classes*

TMMC's evidence refers to allocations and rates applicable specifically to a customer, rather than to the rate class. This can be seen in the derivation of base and standby rates which would specifically apply to TMMC's load.[35] Energy+ on the other hand is allocating all costs to the applicable rate class, Large Use in this case, not to specific customers.

### *Direct Allocation in respect of TMMC's usage*

Energy+'s current proposal is to not perform a direct allocation of assets.[36] In its argument in chief, Energy+ did indicate, however, that

> Energy+ is not opposed to utilizing direct allocation where the facts support such an approach. Energy+ believes that there is sufficient and credible evidence available to justify the direct allocation of the dedicated TMMC feeder costs to the Large User customer class, and that such direct allocation should also account for the capital contribution paid by TMMC in support of those feeder costs.[37]

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[32] EB-2015-0002.

[33] EB-2015-0002 Decision and Order, pp. 15-16.

[34] EB-2015-0002, Draft Rate Order Cost Allocation Model for 2015, I6.2 Customer Data.

[35] Updated Pollock Evidence, *op. cit.*, Schedules JP13, JP14.

[36] Response to TCQ-VECC-76.

[37] Argument-in-Chief, page 20.

While not opposed to the direct allocation of feeder costs, “Energy+ is of the view that no other costs should be directly allocated to the Large User customer class.”[38]

TMMC proposes a direct allocation to TMMC of all assets used by TMMC, with the exception of poles,[39] namely the costs of, and associated with the dedicated feeder, net of capital contributions.

***Allocation of common assets with respect to TMMC usage***

The customers of Energy+ are served by seven transformer stations which step power down from transmission voltages to distribution voltages. Five of these are owned by Hydro One, the costs of which are recovered from all customers. One transformer station is owned by Energy+ on its own, and one transformer station is jointly owned by Energy+ and BPI. Energy+’s investment in the transformer stations are treated in the cost allocation model as bulk assets.

In Energy+’s view, bulk distribution costs should be allocated to the Large Use rate class on the basis of the full rate class load including TMMC, as these assets are normally allocated to all customers regardless of each customer’s individual service connection.[40] Energy+ is proposing that both overhead and underground facilities including poles, conduit, and conductor be allocated to the Large Use rate class on the basis of the full rate class load including TMMC, whether or not they are used by TMMC. In the event that a direct allocation of the feeder is performed, then Energy+ proposes that only underground conduit and poles be allocated to the Large Use rate class. This is consistent with the treatment of all other rate classes which are allocated costs of both overhead and underground assets regardless of the specific assets used to provide service.[41]

TMMC does not propose to allocate any proportion of Energy+’s bulk assets to TMMC as it does not use nor have access to any of Energy+’s transformer stations.[42] Instead, it notes that it is served exclusively by a Hydro One transformation facility, Preston TS. When asked why TMMC should be excused from paying a share of the bulk transformer stations, yet other customers not be

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[38] Argument-in-Chief, page 20.
[39] Updated Pollock Evidence, *op. cit.*, page 8.
[40] Argument-in-Chief, page 20-21.
[41] Argument-in-Chief, page 21.
[42] Updated Pollock Evidence, *op. cit.*, page 8.

excused from paying for Hydro One transformer stations, Jeffrey Pollock responded with respect to his evidence on behalf of TMMC “I have not addressed the allocation of the RTSR charges; I have only addressed the allocation of bulk facilities.”[43]

TMMC also reasons that it should not have to pay for any underground assets including feeders or conduit because it does not use these assets.[44] In questioning why TMMC did not allocate underground conduit, SEC drew parallels between the function of poles and underground conduit. It reasoned that poles and conduit serve the same function in a distribution system “poles hold conductors, underground conduits also hold conductors, correct?”[45] SEC noted that the “allocator for poles consists of the loads of all customers using overhead or underground systems”, and raised the concern that in fairness if TMMC’s proposal were to be adopted, customers who don’t use poles shouldn’t have to pay for poles. OEB staff agrees with SEC that to allow one customer to opt out of paying for underground facilities on the basis of being served with overhead facilities is inappropriate when all other customers are paying for both overhead and underground service regardless of their actual connection.

TMMC proposes that allocation of poles based on its demand is appropriate given that it makes use of poles that are part of the pooled assets of Energy+, i.e. they provide service to TMMC as well as other customers by holding both TMMC’s dedicated feeders as well as feeders serving other customers.[46]

Table 3 outlines proposed allocated cost by rate class of Energy+’s proposal as compared to TMMC’s proposal:

[43] Oral Hearing, Day 2, page 65.
[44] Updated Pollock Evidence, *op. cit.*, page 17.
[45] Oral Hearing, Day 2, page 61.
[46] Updated Pollock Evidence, *op. cit.*, page 8.

**Table 3. Comparison of Cost Allocation Results**

| Rate Class | Energy+ Allocated Costs[47] | TMMC Allocated Costs[48] | Difference |
|---|---|---|---|
| | A | B | B-A |
| Residential | $22,647,403 | $22,785,595 | $138,192 |
| GS <50 | $4,104,546 | $4,166,614 | $62,068 |
| GS> 50- 999 kW | $5,633,608 | $5,839,746 | $206,138 |
| GS> 1,000 - 4,999 kW | $2,012,791 | $2,118,667 | $105,875 |
| Large Use | $1,108,381 | N/A | -$510,323 (combined) |
| Large Use 1 | N/A | $206,108 | |
| Large Use 2 | N/A | $391,949 | |
| Street Light | $494,733 | $493,134 | -$1,599 |
| Sentinel | $23,394 | $23,223 | -$171 |
| Unmetered Scattered Load | $78,303 | $78,079 | -$224 |
| Embedded Distributor Hydro One - CND | $43,414 | $43,481 | $67 |
| Embedded Distributor Waterloo North Hydro - CND | $157,923 | $157,897 | -$27 |
| Embedded Distributor Hydro One 1 - BCP | $29,542 | $29,537 | -$5 |
| Embedded Distributor Brantford Power - BCP | $12,850 | $12,859 | $9 |
| Embedded Distributor Hydro One 2 - BCP | $2,978 | $2,978 | $0 |
| **Total** | **$36,349,867** | **$36,349,867** | **$0** |

OEB staff notes that the majority of the savings to the Large User rate classes from the TMMC approach are the result of its proposals for direct allocation, standby, and allocation of pooled costs with respect to TMMC's load. The benefit of these changes flow directly to TMMC under its proposal.

[47] VECC-TCQ-76, Revenue Requirement Workform, Tab 11. Cost Allocation.
[48] Updated Pollock Evidence, *op. cit.*, Table 9, filed March 1, 2019

### *Confidentiality*

As Energy+ proposes both Large Use customers within a single rate class with allocation of all costs, there is less concern with confidentiality of individual customer data. The proposed cost allocation model has been filed on the public record without the need for redaction.[49]

TMMC had requested and been granted confidential treatment with respect to its load information.[50] In presenting its case it has filed several cost allocation models, interrogatory responses, as well as its consultant's reports in confidence with redacted versions filed on the public record. At the oral hearing, TMMC agreed that its load data can be provided on the public record once aggregated or "rolled up" to an annualized level.[51]

### *OEB Staff Submission*

### *Number of Large Use Rate Classes*

The decision to create a new rate class requires the balancing of many factors. An underpinning objective of cost allocation is that similar customers be treated similarly, and different customers be treated differently.[52] To facilitate this, rate classes are created based on their characteristics.

Inherently, no two customers are identical, and differences between similar customers can lead to differences in the cost to provide services. Therefore there needs to be a balance between the number of rate classes created and the level of cross subsidization within a class.

TMMC referred to separate rate classes for customers of EnWin Utilities and Alectra Utilities. While TMMC has installed a LDG facility, and identifies it as one of its four distinguishing characteristics that necessitates differential treatment from the other Large User, OEB staff notes that neither the presence of a LDG nor large customer size are common features in those examples. What is a common characteristic is the use of dedicated feeders to the customers.

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[49] Response to TCQ-VECC-76.

[50] Procedural Order No. 3, October 5, 2018.

[51] Oral Hearing, day 2, page 10.

[52] James C. Bonbright, Principles of Public Utility Rates, pp. 383-384.

In the case of EnWin Utilities, OEB staff notes that the separate classes were created in 2002 which predates the issuance of the OEB's current cost allocation policy.[53] It is unclear whether the same treatment would have been applied in the context of the current cost allocation policy.

Alectra's Large Use (2) rate class was created in Horizon's 2015 Custom IR[54] rate application under essentially the same cost allocation policy as exists today. However, the existence of at least five customers in each class following the subdivision of the Large Use class has created a different dynamic. In the Horizon case, there was a group of customers with a similar concern and similar characteristics that were requesting to be treated equally. In this case, there is one customer, looking to be treated differently.

OEB staff is concerned that, if specific/unique criteria is a basis for creating a separate rate class for an individual customer, such an approach could give rise to numerous more classes with unique characteristics. Energy+ has noted that it has customers in the General Service greater than 50 kW class that are located within close proximity of a transformer station.[55] It is possible that other characteristics could give rise to more classes. If additional classes are required, Energy+ is concerned that it would be required to maintain a record of capital and operating costs associated with each customer.[56]

When a customer seeks to differentiate its service requirements and therefore its rates from others, it's necessary to consider how the proposal reconciles with the concept of postage stamp rates. That is, that customers receiving equal service to meet equal needs should be charged the same rates. In his principle of fairness, Bonbright has asserted that equals be treated equally.[57] Some customers will cost more to serve than others. Some of this difference will be due to factors within the customer's control, and some will be due to accidents of location. Many of these factors are more in the control of the distributors than customers, such as the age of assets used to provide service and the location of

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[53] EB-2007-0667, Report of the Board: Application of Cost Allocation for Electricity Distributors, November 28, 2007.
[54] EB-2014-0002.
[55] Oral Hearing, Day 1, page 21.
[56] *Ibid.*
[57] James C. Bonbright, Principles of Public Utility Rates, page 383-384.

distribution assets, and therefore it wouldn't be fair to differentiate customer bills on these factors.

In light of the burden imposed by creating another rate class, and the precedent of doing this for a single customer[58], OEB staff submits that a single rate class for all Large Use customers is appropriate.

***Allocation to customers or rate classes***

OEB staff submits that direct allocation should be applied to a rate class with respect to assets used exclusively by individual rate classes. Rates are set for rate classes to recover the allocated costs within a range of accepted revenue to cost ratios. Customers pay the rates ordered for their rate class. Since customers in the same class do not pay individualized rates, it would not be sensible to perform direct allocation to customers.

***Direct Allocation in respect of TMMC's usage***

OEB staff agrees with TMMC that direct allocation with respect to costs associated with the dedicated feeder, net of capital contributions, is appropriate.

***Allocation of common assets with respect to TMMC usage***

*Feeders*

OEB staff notes that the dedicated overhead feeders used by TMMC fully satisfy its need for primary distribution feeders. The other Large Use customer is using feeders from the common pool of primary distribution assets. All customers are normally allocated both overhead and underground asset costs regardless of the actual connection. In the case of TMMC, it is served only by overhead assets. Other customers may make use of underground assets, but in doing so, they make proportionately less use of overhead assets than if every section of wire were overhead. The allocation of both overhead and underground costs to all customers is also reasonable, because it is not up to the customer whether the feeders providing service to them are overhead or underground. Therefore, OEB staff submits, that both overhead and underground conductors should be allocated to the Large Use rate class on the basis of the usage of the other (not TMMC) Large Use customer.

[58] Oral Hearing, Day 1, page 21.

*Poles*

As confirmed on cross examination,[59] both TMMC and the other Large Use customer make use of poles, as both are served by overhead feeders. With respect to underground conduit, OEB staff is of the view that the use of overhead poles and underground conduit serve the same role in the system, i.e. to hold conductor, the selection of which is dictated only based on whether the conductor is overhead or underground, and that is largely out of the control of the customer. Both of these assets are typically allocated to all customers on the basis of their usage. OEB staff submits that both poles and underground conduit be allocated to the Large Use rate class on the combined requirements of both Large Use customers.

*Bulk Assets*

OEB staff notes that transmission stations owned by LDCs are categorized as bulk assets and allocated through the cost allocation model, while transmission stations owned by a transmission company are charged to the distributor through Uniform Transmission Rates (UTRs), and normally recovered through RTSRs. Customers do not have a choice whether they are connected to an LDC owned transformer station, or a transmission company owned transformer station. Both bulk assets and RTSRs are charged to all customers. OEB staff submits that the Large Use rate class should be no different, i.e. the demand of both customers should be used to determine the allocation of the bulk assets.

### *Confidentiality*

OEB staff notes that in order to implement its proposals with respect to cost allocation, the cost allocation model would need to use an allocator which reflects total demand of the Large Use rate class, and a separate allocator which reflects demand of only one customer in the rate class (i.e. excluding TMMC). Depending on the derivation, by subtracting these demand allocators, it would be possible to arrive either at a reasonable estimate, or exactly the demand allocators that would apply to TMMC alone. The use of a single rate class does, however, aggregate other aspects of individual customer use, such as annual kWh. TMMC has stated that it is agreeable to its usage being provided on an aggregate “rolled up” basis. OEB staff submits that based on these factors, it should be possible to

[59] Oral Hearing, Day 1, page 187.

create a cost allocation model consistent with this submission which does not require confidential treatment.

### b. Embedded Distributor Class Revenue to Cost Ratio

***Background***

The methodology for cost allocation for embedded distributors that was used by Energy+ in its application is taken from the OEB's 2011 Report which is incorporated into Appendix 2-Q in Chapter 2 of the Filing Requirements[60], providing direction on how to allocate costs to embedded distributors. Energy+ used Appendix 2-Q to determine the percentages of distribution assets used by each embedded distributor. These percentages were then used to drive direct allocations to the embedded distributors. The approach of using Appendix 2-Q as opposed to simply allowing the cost allocation model to allocate costs, as well as the issue of whether bulk asset costs should be allocated to embedded distributor classes have been determined to be out of scope in this proceeding.[61]

Energy+ proposed that the revenue to cost ratio for embedded distributors be set to 100% as it is consistent with the treatment in 2014.[62]

The OEB has set policy ranges for revenue to cost ratios for rate classes. The most complete list is found in the 2011 Review of Electricity Distribution Cost Allocation Policy.[63] This listing does not include a range for embedded distributors, but a majority of rate classes, including the default rate class for embedded distributors, General Service 50 to 4,999 kW, have a range of 80 to 120%.

***OEB Staff Submission***

OEB staff notes that the accepted policy is that revenue to cost ratios outside the ranges established by the OEB should be moved within the range.[64] It is expected that distributors will move only to the boundaries of the range, and

[60] Filing Requirements For Electricity Distribution Rate Applications, Chapter 2, Cost of Service, July 12, 2018.
[61] Decision on Embedded Distributor Cost Allocation, March 4, 2019.
[62] Settlement Proposal, page 30.
[63] EB-2010-0219, Report of the Board: Review of Electricity Distribution Cost Allocation Policy, March 31, 2011, page 36.
[64] EB-2007-0667, Report of the Board: Application of Cost Allocation for Electricity Distributors, November 28, 2007, page 6.

requests to narrow ranges with the objective of moving revenue to cost ratios closer to 100% are denied where the movement is not supported by sufficient information.[65] While exceptions have been made, these have been granted on an individual basis based on particular circumstances, and are not the norm.

Energy+'s cost allocation methodology results in four embedded distributor rate classes having a revenue to cost ratio of over 120%, and one embedded distributor having a revenue to cost ratio of under 80%.[66]

In OEB staff's view, a past decision of moving revenue to cost ratios to 100% does not justify moving revenue to cost ratios to 100% in future proceedings. The OEB provides policy ranges for several reasons. One is the level of confidence the OEB has in the accuracy of the current allocation. The current policy states "The Board's policy remains that distributors should endeavor to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations."[67] Given the presence of out-of-scope items, OEB staff submits that the improved information required to move the revenue to cost ratio closer to one does not exist at this time. Another reason for using revenue to cost ranges is to provide a range in which revenue to cost ratios can fluctuate without impacting rate stability. OEB staff notes that by adjusting a revenue to cost ratio to the nearest boundary rather than to 100% necessarily results in a smaller rate impact in this proceeding. This reduces the impact both for the embedded distributors who are outside the range, moving to a nearer boundary than 100%, and for customers of the Residential, Sentinel, and Unmetered Scattered Load rate classes which Energy+ proposes make up the shortfall from reducing the revenue-to-cost ratios for other rate classes.[68]

OEB staff therefore submits that where the revenue to cost ratio for the embedded distributor class is above the ceiling or below the floor, it be set to the nearest boundary. OEB staff also submits that the applicable range for the embedded distributor rate class is 80% to 120%.

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[65] EB-2013-0416, Decision, March 12, 2015, page 45.

[66] VECC-TCQ-76, Revenue Requirement Workform, Tab 11. Cost Allocation.

[67] EB-2010-0219, Report of the Board: Review of Electricity Distribution Cost Allocation Policy, March 31, 2011, page iii.

[68] VECC-TCQ-76, Revenue Requirement Workform, Tab 13. Rate Design.

## III. Issues 3.3 & 3.4 Rate Design

### a. Large Use Class Fixed Charge

***Background***

Energy+ proposes to increase the fixed charge for the Large Use class to $9,210.42[69] from $8,976.06. The current fixed charge is already above the ceiling value established by the minimum system with peak load carrying capacity adjustment.

Section 2.8.1 of the Filling Requirements states:

> 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 nonresidential class. [70]

***OEB Staff Submission***

In accordance with the Filling Requirements, OEB staff submits that the fixed charge for the Large Use class should remain at the existing level of $8,976.06.

### b. Rate Mitigation

***Background***

Energy+ proposes to harmonize distribution rates for customers in the CND and BCP service territories.

The total bill impacts for low volume residential customers are in the range of 12.2% to 13.3% for all scenarios.[71] In its argument-in-chief, Energy+ proposes to mitigate the total bill impact on low volume residential customers by deferring the transition to a fully fixed monthly service charge for the residential class by one additional year to reduce the bill impact to less than 10%.[72]

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[69] VECC-TCQ-76, RRWF tab 13.

[70] Ontario Energy Board *Filing Requirements For Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications- Chapter 2, section 2.2.2.3.*

[71] Oral Hearing, March 7, 2019, Exhibit K1.6, Appendix A, Bill Impact Scenarios.

[72] Argument in Chief, March 15, 2019, paragraph 68.

*OEB Staff Submission*

OEB staff supports the proposed mitigation plan. However, as detailed further in this submission in section VI, OEB staff submits that the Group 2 DVA balances should be disposed by rate zone. Additional mitigation may be required if the OEB determines that the Group 2 DVA account balances should be disposed separately by rate zone. Energy+ should confirm this as part of its reply submission.

## IV. Issues 3.5 & 3.6 Retail Transmission Service Rates & Low Voltage Rates, including gross load billing of RTSRs

### a. Retail Transmission Service Rates

*Background*

Energy+ is a transmission connected and partially embedded distributor. For the CND service area, Energy+ is partially embedded in Hydro One’s distribution system. For the BCP service area, Energy+ is partially embedded in Hydro One’s and BPI’s distribution systems. Energy+ is billed UTRs by the Independent Electricity System Operator (IESO), sub-transmission RTSRs by Hydro One, and embedded distribution RTSRs by BPI. Energy+ passes these charges on to customers through RTSRs.

As part of the rate harmonization plan, Energy+ proposes to harmonize RTSRs utilizing the following steps:[73]

- Prepare the RTSRs workform for each of the CND and BCP service territories to determine the RTSRs for each rate zone
- Apply these rates to the 2019 load forecast by rate class and by service territory to determine the total dollars to be collected by each rate class
- Divide the calculated total dollars by the 2019 load forecast for each rate class to determine the harmonized RTSRs

[73] Exhibit 8, page 16.

To account for the proposed gross load billing methodology (see section IV, part b), Energy+ adjusted the billing demand by 74,376 kW for the Large Use class for the purpose of determining RTSRs.[74]

Energy+ confirmed that for the Hydro One No.2 embedded distributor class in the BCP service area, Hydro One invoices the RTSRs charges to Energy+'s portion of the load only, therefore, RTSRs do not apply to Hydro One No.2.[75]

***OEB Staff Submission***

Energy+ provided a revised load forecast model and corrected the 2019 forecast demand for Hydro One No.1 in the BCP service territory. OEB staff notes that it appears this correction was not reflected in the RTSRs workform for the BCP service territory.[76] OEB staff asks Energy+ to confirm in its reply submission, whether a revision is required for the proposed harmonized RTSRs.[77]

OEB staff also notes that the adjustment of 74,376 kW on Large Use class billing demand would not be required if the OEB determines not to implement gross load billing for RTSRs in this proceeding.

### b. Gross Load Billing

***Background***

Energy+ is charged on a gross load billing basis by the IESO for wholesale transmission services since it has a Large Use customer with LDG. Energy+ proposed to charge the RTSRs to this customer on a gross load basis. Energy+ also requested the gross load billing methodology for RTSRs for any customer in the future that implements LDG to align to the methodology used by the IESO.

Energy+ originally stated that the proposed gross load billing methodology applies to Retail Transmission Rate – Line and Transformation Connection Service Rate and LV Rates.[78] In response to a technical conference question, Energy+ confirmed that neither Hydro One nor BPI use gross load billing for LV

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[74] In responses to VECC-TCQ-80 part a, Energy+ revised the demand adjustment for Large Use class from 30,443 kW (reflecting the standby contract capacity) to 74,376 kW (reflecting the gross load billing impact).

[75] Energy+ Responses to Technical Conference Undertakings, JTC1.4.

[76] Technical Conference Undertaking JTC 1.4, RTSR Workform BCP, tab 4, cell G35.

[77] Energy+ Responses to Technical Conference Undertakings, JTC 1.4.

[78] 8-Staff-88.

charges to Energy+.[79] Energy+ therefore revised its proposal to remove the request to gross load bill its LV rates for customers who have LDG.

Energy+'s proposal to use gross load billing for its Retail Transmission Rate – Line and Transformation Connection Service Rate applies to all customers with LDG regardless of size.[80]

Energy+ also confirmed that during the previous IRM term the LDG customer was not charged on a gross load billing basis, resulting in an estimated $260,228 debit variance in the RTSRs connection variance account (Account 1586).[81] The RTSRs connection variance account is then being allocated to all rate classes.

***OEB Staff Submission***

OEB staff agrees with Energy+ that there is merit in aligning the amounts charged to the LDG customer with what the distributor is billed by the IESO. The proposed methodology would ensure that there are no cross-subsidies between customers.

However, OEB staff notes that by a letter dated March 29, 2016, the OEB informed electricity distributors that:

> The Ontario Energy Board (OEB) is initiating a policy review to address the question of how a commercial and industrial customer should be billed when they have a Load Displacement Generator (LDG) behind the meter. This issue is already being considered in the policy review for distribution rates as part of the OEB's project on Rate Design for Electricity Commercial and Industrial Customers (EB-2015-0043). The OEB will also undertake a review of the appropriate billing for other rates such as Retail Transmission Service Rates (RTSR) and other elements of the bill including the Global Adjustment (GA).

OEB staff also notes that in a more recent decision on Enwin Utilities' 2018 rates, the OEB stated that "the OEB may review this matter further on a generic basis and provide information in due course. EnWin Utilities should continue to use the

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[79] VECC-TCQ-79.

[80] VECC-TCQ-80 part d.

[81] 8-Staff-92.

same approach to the settlement of these activities as it has been using to date".[82]

OEB staff is of the view that this gross load billing issue is a complex matter and that Energy+ should continue to use the same approach to the settlement of these activities as it has been using to date pending any further direction from the OEB.

### c. Low Voltage Rates

#### *Background*

Energy+ serves five embedded distributors, two in the former CND service territory, and three in the former BCP service territory. Energy+ proposes to maintain its present treatment of not applying LV charges to these customers.[83]

The specific circumstances around Energy+'s embedded distributors vary depending on the source of supply Energy+ uses for each one. In one instance, Energy+ takes its supply from Hydro One as a sub transmission customer. It uses the feeder to serve several of its own customers before serving Hydro One as an embedded distributor. For this feeder, Energy+ has an arrangement with Hydro One that Hydro One's sub transmission rates are charged based only on the power consumed by the connected Energy+ customers and that Energy+ reciprocate by not charging LV charges for the power delivered back to Hydro One.[84]

On a second feeder, Hydro One is embedded as a distinct customer of Energy+ in a distinct rate class. Also on this feeder, Energy+ is embedded in BPI. Energy+ pays LV charges to BPI in respect of both its own load and Hydro One's load.[85] Energy+'s feeders serving the embedded customers Waterloo North and BPI, are connected directly to transformer stations.

#### *OEB Staff Submission*

OEB staff notes that the payments a distributor makes to its host distributor, and recovers through LV charges, recover costs related to the same functions that it would normally perform for its customers, i.e. primary distribution. These costs

[82] EB-2017-0037, Decision and Rate Order, March 22, 2018.
[83] Oral Hearing, Day 1, page 141.
[84] Oral Hearing, Day 1, page 133.
[85] Oral Hearing, Day 1, page 134.

are incurred by Energy+ in lieu of Energy+ owning the distribution assets directly, and recovering the costs through its cost allocation. Had the assets been owned by Energy+, the cost recovery would be the responsibility of all Energy+ customers as these costs would have been included in the totals allocated in the cost allocation model, and in Appendix 2-Q for embedded distributors.

Energy+ states it does not charge any of its embedded distributors for LV service. However, these customers are currently in the General Service 50 to 4,999 kW rate class for the BCP service area. To charge embedded distributors for LV would be consistent with the derivation of the LV charge itself where the full class load was used to determine all aspects.[86] The current tariff for this rate class indicates an LV charge of $1.1222/kW, and does not indicate any differential treatment for embedded distributors.[87] Therefore, Energy+ should be charging these embedded distributor customers for low voltage.

OEB staff also notes that there is precedent for LV charges being applied on the tariffs of rate classes dedicated to embedded distributors, such as Canadian Niagara Power,[88] E.L.K. Energy Inc.,[89] Entegrus Powerlines Inc.[90] and Oakville Hydro Electricity Distribution Inc.[91]

However, OEB staff agrees with Energy+ that where a feeder passes through its service territory, it is both host and embedded on that feeder to the same distributor. Hence, if it has a reciprocal agreement with that distributor to not apply sub transmission charges in exchange for not applying LV charges in respect of the same load, then it is appropriate to not apply LV charges. In all other instances, OEB staff submits that for the reasons outlined above, LV charges should apply to embedded distributors.

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[86] EB-2010-0125, Decision and Order, Appendix L.

[87] EB-2017-0030, Decision and Rate Order, Schedule A, Tariff of Rates and Charges for Brant County Power page 3.

[88] EB-2017-0031.

[89] EB-2017-0036.

[90] EB-2017-0033.

[91] EB-2017-0067.

## V. Issue 3.7 Standby Charge

### *Background*

Energy+ proposed standby charges using a contracted capacity method where a customer contracts for a peak load requirement, initially based on the actual historical peak demand of the customer. The contracted capacity could be reduced if the customer demonstrates an ability to shed load.[92] Energy+ proposed a standby rate which is the same as the volumetric rate of the customer's rate class. This has the effect that the distribution charge is the same regardless of the customer's consumption, as long as it is not more than the contracted capacity.[93] In the event that a customer's load exceeds the contracted capacity, the customer would be billed for actual demand. Energy+ did not propose a penalty for exceeding the contracted capacity, but would consider a need to revise the contracted capacity should the customer exceed the contracted amount.[94]

The standby charge would apply "for all GS 50-999 kW, GS 1000-4999kW, and Large Use customers that have load displacement generation and require Energy+ to act as a backup supply of electricity in the event the source of generation is unavailable."[95] Energy+ states that it needs to dedicate, operate, maintain, and ensure that an appropriate amount of capacity is available when customers require it, and that in the absence of a standby charge, costs will be shifted to other customers due to decreasing metered volumes.[96]

With respect to the provision of standby service to TMMC, Energy+ noted that Hydro One's Preston TS will be in need of replacement transformers, which are approaching their end of life. In doing so, the capacity of the upgraded station would therefore depend on the requirements of the connected load including TMMC and new customers expected in the east side lands of Cambridge.[97] This is not to indicate that the costs of this represent a direct cost to Energy+

[92] Argument-in-Chief, page 25.
[93] Oral Hearing, Day 1, page 98.
[94] Oral Hearing, Day 1, page 102.
[95] Argument-in-Chief, page 25.
[96] Argument-in-Chief, page 26.
[97] Oral Hearing, Day 1, page 22.

customers today, but to indicate that the reservation of capacity imposes costs to the system, and impacts system renewal and expansion costs.

TMMC proposed a two-part standby charge consisting of, firstly, a contracted capacity charge based on TMMC's proposed standby contract demand of 6,900 kW[98] and secondly, a daily charge based on an allocation of the cost of shared facilities (poles) for those working days[99] when TMMC requires delivery of standby services due to an outage of its LDG.

Using 2017 actual data, the total annual cost of the standby service proposed by Energy+ is $71,304.[100] As proposed by TMMC, the annual cost is under $2,000.[101]

Other distributors such as Hydro Ottawa Limited (Hydro Ottawa) and Kingston Hydro Corporation (Kingston Hydro) offer a contracted capacity standby service. While Energy+ is proposing that its contracted capacity would be based on the total of power delivery and standby, the approach used by Hydro Ottawa and Kingston Utilities is to apply the distribution rate to metered demand and apply a standby charge based on the contracted capacity of standby power and a standby rate. Where the customer requires delivery of some or all of the contracted standby service, the metered consumption would reflect this, and the standby charge would be reduced accordingly to reflect any remaining capacity that was still standing by.

***OEB Staff Submission***

OEB staff submits that the standby charge as proposed by Energy+ is appropriate. While it is not the same as that used by Hydro Ottawa and Kingston Hydro, the Energy+ proposal has several merits including:

- Utility is not required to identify when standby service is called upon
- Utility does not need to have  the ability to measure the portion of metered demand that is the result of a full or partial LDG generator outage
- By including the full contracted capacity including standby in the demand allocators in the cost allocation model, it ascribes a tangible charge to the

[98] Updated Pollock Evidence, *op. cit.*, page 28.
[99] TMMC uses the term peak days to reference weekdays excluding holidays between the hours of 7am and 7pm.
[100] 30,443 kW x 2.3422 $/kW.
[101] Updated Pollock Evidence, *op. cit.*, filed March 1, 2019, Schedule JP-16 Revised.

provision of standby services. This reflects the real costs that the provision of standby service imposes on the distributor.

- The use of a single rate for delivered power and standby power simplifies rate design

Conversely, the method proposed by TMMC.

- Requires a new means of tracking outages; the tracking and implementation of which may exceed the revenue these charges could be expected to generate
- Requires a multi-part rate calculation outside of the models used for other rate classes[102]
- Reflects incremental standby revenue of only about $2,000 per year

The proposed concept of a daily rate is inconsistent with every other standby charge currently implemented in Ontario.

From a practical viewpoint, Energy+ has demonstrated that it can calculate standby rates using the OEB supplied rate models. In doing so, it is also able to demonstrate that the total rate revenue reconciles to the base revenue requirement.[103] Under TMMC's proposed methodology it is unclear how revenue from TMMC's daily rate would be reflected in the revenue requirement as a reconciliation was not provided.[104]

Finally, OEB staff notes that a staff paper has made several proposals for standby rates.[105] As a staff paper, this is not the policy of the OEB, however, it is foreseeable that a policy could be developed prior to Energy+'s next rebasing. OEB staff submits that whatever method for standby charges is approved in this proceeding, given the generic policy and any transition has not been determined, it would be reasonable for Energy+ to apply the approved standby charge until its next rebasing.

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[102] Updated Pollock Evidence, *op. cit.*, Schedules JP-13, JP-14, JP-15.

[103] VECC-TCQ-76, Revenue Requirement Workform, Tab 13. Rate Design.

[104] Updated Pollock Evidence, *op. cit.*, Schedules JP-14.

[105] EB-2015-0043, Staff report the Board: Rate Design for Commercial and Industrial Electricity Customers, February 21, 2019.

## VI. Issue 4.2 Group 2 Deferral and Variance Accounts

### a. Lost Revenue Adjustment Mechanism Variance Account

***Background***

Energy+ originally applied to dispose of an LRAMVA debit amount of $1,200,452 for lost revenues up to December 31, 2017, including interest to December 31, 2018. Updates to the LRAMVA were made to reflect the final verified savings and adjustments determined by the IESO, corrections to the allocation of savings to its service territories, and a correction to the street light demand savings. As a result of these changes, the LRAMVA balance was updated to a total debit of $1,545,772 ($1,177,449 for the CND service territory and $368,323 for the BCP service territory).

<u>CND Service Territory</u>

In the CND service territory, the LRAMVA debit balance of $1,177,449 consists of CDM program savings from 2014 to 2017 as well as associated carrying charges. The CDM program savings in the CND LRAMVA total include:

- Persisting savings from 2011 to 2013 CDM programs in 2014
- Persisting savings from 2011 to 2014 CDM programs in 2015
- Persisting savings from 2011 to 2015 CDM programs in 2016
- Persisting savings from 2011 to 2016 CDM programs in 2017
- New savings from 2017 CDM programs in 2017

Actual savings were compared against forecast savings of 39,520,173 kWh, set out in the former CND's 2014 cost of service proceeding.[106]

<u>BCP Service Territory</u>

In the BCP service territory, the LRAMVA debit balance of $368,323 consists of CDM program savings in 2016 and 2017 as well as associated carrying charges. The CDM program savings in the BCP LRAMVA total include:

- Persisting savings from 2011 to 2015 CDM programs in 2016
- Persisting savings from 2011 to 2016 CDM programs in 2017

[106] Decision and Order, EB-2013-0116, August 14, 2014.

- New savings from 2017 CDM programs in 2017

Actual savings were compared against forecast savings of 1,494,000 kWh, set out in the former BCP's 2011 cost of service proceeding.[107]

Energy+'s LRAMVA calculations were prepared by a consultant. The consultant report was filed with the application.[108]

***OEB Staff Submission***

**Summary**

OEB staff supports Energy+'s disposition of the updated LRAMVA debit amount of $1,545,772. OEB staff submits that Energy+ has appropriately relied on the final verified results from the IESO when calculating its lost revenues from all programs, other than the demand savings from the CHP project completed through the IESO's Process and Systems Upgrade (PSU) program and the street lighting upgrades undertaken through the IESO's saveOnEnergy Retrofit program. Further, Energy+ has followed OEB policy[109] and compared actual CDM savings with CDM savings forecasts approved as part of the last cost of service applications of the former utilities.

OEB staff supports the disposition of Energy+'s LRAMVA balance over a one-year period based on the last submitted versions of the LRAMVA workform:

- EnergyPlus_CND_OEB LRAMVA workform v3.52_1 Staff 64_20180914
- EnergyPlus_UR_JTC 1-8_BCP_OEB LRAMVA work form v3-53_20190205

OEB staff discusses the following four specific aspects of Energy+'s LRAMVA request in more detail below:

1. No service territory specific CDM results for 2016 and 2017 program years
2. Lost revenues related to a large CHP project
3. Disposition of CHP lost revenues
4. Demand savings from street light upgrades

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[107] Decision and Order, EB-2010-0125, May 9, 2011.
[108] Exhibit 4, pp. 300-317.
[109] Guidelines for Electricity Distributor Conservation and Demand Management, EB-2012-0003, April 26, 2012; and Requirement Guidelines for Electricity Distributors Conservation and Demand Management, EB-2014-0278, December 19, 2014.

## 1. No Service Territory Specific CDM Results in 2016 and 2017

### *Background*

The Final Verified Results for Energy+ were reported on a harmonized basis for 2016 and 2017. Following the amalgamation of the former CND and BCP on January 1, 2016, the CDM savings results for each former utility were no longer reported by the IESO.

In the absence of this information, Energy+ prorated the CDM savings by service territory using project-specific information for its 2016 and 2017 lost revenue calculations. In the event project-specific information was not available, Energy+ apportioned the CDM savings based on relative consumption of the service territories.[110]

### *OEB Staff Submission*

OEB staff submits that Energy+'s proposal to determine service territory LRAMVA balances for 2016 and 2017 is reasonable. Energy+ has appropriately relied on the best information available to allocate its LRAMVA balances resulting in service territory specific amounts.

## 2. Lost Revenues from CHP Project

### *Background*

Energy+ included the recovery of lost revenues from a CHP project undertaken as part of TMMC's participation in the IESO's PSU – Project Incentive Initiative. The lost revenues from the CHP project amount to $364,022 for 2016 and 2017. Energy+ proposes to recover the lost revenues from the Large Use class. TMMC represents about 80% of the Large Use load.[111]

For the recovery of lost revenues from the CHP project, Energy+ proposes to calculate demand savings from the CHP project by taking the difference between two peaks on a monthly basis as follows:[112]

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[110] Response to 4-Staff-66 and Tab 3-a of LRAMVA workform (CND and Brant County service territories).

[111] Technical Conference Transcript, Vol. 2, page 41.

[112] Oral Hearing Transcript, Vol. 1, pp. 25-26.

(i) The first peak was the hour and the month when the customer had the highest demand on the Energy+ feeders. This is the demand Energy+ used to bill the customer throughout the time frame.

(ii) The second peak was the hour and the month when the customer had the highest demand for the entire facility. This includes the demand from the Energy+ feeders and the output of the generation.

In its argument-in-chief, Energy+ stated that it recognizes that its proposed methodology varies from the approach identified in the OEB's Updated LRAMVA Policy on the Lost Revenue Calculation for Demand Savings (Updated LRAMVA Policy).[113]

Energy+ stated that its proposed approach of utilizing the peak demand of the facility (inclusive of generation) represents a 'verifiable proxy' for the demand that the customer would have been billed for in absence of the CHP project.[114] Energy+ believes that its alternative methodology is appropriate for the following reasons:

(i) the IESO methodology of multiplying 12 months of savings times average monthly peak would not reasonably estimate the impact on revenue of large PSU projects

(ii) it was more appropriate to assess actual impacts on revenues from large projects

(iii) the average demand savings associated with a large CHP project do not necessarily translate into lost revenues, given that revenues were based on monthly peaks[115]

Although Energy+'s 2016 and 2017 Final Verified Results Report from the IESO did not include demand savings from the PSU program,[116] TMMC subsequently provided the Measurement & Verification (M&V) reports prepared by IESO evaluation consultants to demonstrate that savings for 2016 and 2017 were verified at the facility.[117]

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[113] Updated Policy for the LRAMVA Calculation, EB-2016-0182, May 19, 2016 (Updated LRAMVA Policy).

[114] Oral Hearing Transcript, Vol. 1, page 26.

[115] 4-Staff-68 b).

[116] 2016 and 2017 Final Verified Results Report for Energy+.

[117] K1-1, Energy+ Responses to TC Questions Part 1 Question #4 e); and K1-2 Redacted Confidential, TMMC Responses to TC 1 a) and b) from Energy+, Attachments A and B.

***OEB Staff Submission***

OEB staff supports Energy+'s proposed methodology to calculate its LRAMVA balance related to the CHP project. OEB staff notes that the calculation of demand savings from a CHP generator using a non-standard evaluation methodology is the first of its kind before the OEB.

The Updated LRAMVA Policy provides direction to distributors on how to calculate lost revenues that result from demand savings from energy efficiency programs. The Updated LRAMVA Policy indicates that distributors should rely on the IESO's final verified peak demand savings results and multiply those savings by certain monthly multipliers. For the PSU program, it indicates that the IESO verified savings should be multiplied by twelve to acknowledge the savings occurring over the course of the entire year. The Updated LRAMVA policy further states that "should a distributor wish to propose an alternative approach, the onus would be fully on the distributor to support its proposal."[118]

Energy+ has proposed an alternative methodology to determine actual lost revenues from the CHP project to the utility. Typically, distributors are expected to rely on the IESO's final savings results to calculate lost revenues. As part of the CHP project, M&V activities were undertaken by IESO evaluation consultants. The M&V reports indicate the estimated summer peak demand savings for this CHP project, and an estimation of the average demand savings from the summer peak. As noted in the Updated LRAMVA Policy, summer peak demand is defined as savings that occur on weekdays between 1pm to 7pm from June 1 to August 31.

In the absence of more specific analysis of peak demand savings from an energy efficiency project, OEB staff would expect a distributor to rely on the IESO results. However, in this application, Energy+ provided its own detailed analysis of the peak demand savings from the CHP project by way of actual metered data. Energy+ used the actual metered data to approximate lost revenues based on the facility's operating hours throughout the entire year. Energy+ has followed the OEB's direction in the Updated LRAMVA Policy and provided supporting documentation for its utility-specific proposal, including metering data and analysis of the peak hour when the CHP generator was on and off. For

[118] Updated Policy for the LRAMVA Calculation, EB-2016-0182, May 19, 2016, page 6.

perspective, Energy+ indicated that the demand savings for the CHP project are approximately 11% higher when using the IESO M&V results.[119]

OEB staff submits that Energy+'s proposed savings calculation aligns with the manner in which the facility and the customer were billed in 2016 and 2017. In the absence of CHP generation, the baseline was calculated using actual monthly metered data to support the actual peak of the Energy+ facility. With CHP generation, Energy+ has provided the actual monthly metered data to support the actual peak at which it bills TMMC. As a result, the lost revenues to Energy+ are captured based on the difference in maximum monthly peaks at the facility and grid level. OEB staff submits that Energy+'s proposed methodology results in a reasonable estimate of the demand savings from the CHP project.

Although there are IESO results available, it is doubtful that the IESO results provide a more accurate estimate of savings over the course of 2016 and 2017 as the scope of the IESO M&V activities was for the purpose of determining average summer peak demand savings, not specific savings for each month of the year.

OEB staff is of the view that the demand savings proposed by Energy+ for the CHP project represent a reasonable estimate of actual lost revenue impacts throughout the year. OEB staff supports Energy+'s methodology for the reasons discussed above.

### *3. Disposition of CHP Lost Revenues*

#### *Background*

During the oral hearing, TMMC raised a concern that the disposition of LRAMVA related to the CHP project should be allocated across all rate classes. TMMC's rationale was that the CHP project was a provincially funded initiative and therefore all customers should be subject to paying for the lost revenue.[120]

Currently, LRAMVA balances are disposed of to all customers in a class that participated in a CDM program.

[119] Argument-in-chief, page 30.
[120] Oral Hearing Transcript, Vol. 2, page 110.

### *OEB Staff Submission*

Without further analysis or studies showing that the demand savings from the CHP project have benefitted all customers, OEB staff cannot support TMMC's proposal to dispose of the CHP project savings to all customer classes. OEB staff submits that the approach proposed by TMMC is not consistent with the allocation of lost revenues in other LRAMVA claims. OEB staff believes that the continued approach to allocate LRAMVA claim at the participating rate class level is consistent with the cost causality principle, where the user who benefits from participating in IESO's CDM program would be subject to their applicable share of lost revenues.

### *4. Street Light Demand Savings*

### *Background*

In the BCP service territory, $108,446 in lost revenues has been requested from street light demand savings based on Brant County's participation in the saveOnEnergy Retrofit program.

No CDM adjustment for street light upgrades was included in the 2011 load forecast at the time the former BCP rebased. Energy+ takes the difference in total billed demand before and after conversion to a higher efficiency bulb. As street lights are unmetered, Energy+ received reports from the municipality to confirm the number of bulbs replaced to support the demand savings claimed.[121]

### *OEB Staff Submission*

OEB staff submits that the full impact of lost revenues from street light upgrades can be recovered by Energy+, as no CDM adjustment for street light upgrades was included in the 2011 load forecast at the time the former BCP rebased. This approach is consistent with the recovery of street light demand savings claimed in Alectra's 2019 Custom IR update for the Horizon rate zone.[122]

In response to OEB staff interrogatories, Energy+ provided supplementary calculations to show demand billed data by the type of bulb replaced and exchanged for each conversion in 2016 and 2017.[123] OEB staff accepts the

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[121] K1-1, Energy+ Responses to TC Questions Part 1 Question #5 d).

[122] Partial Decision and Order, EB-2018-0016, December 20, 2018.

[123] K1-1, Energy+ Responses to TC Questions Part 1 Question #5 e) excel attachment: 2019 EnergyPlus Streetlight technology - Staff TC 5.

methodology to estimate street light demand savings, which is based on the difference in total billed demand before and after conversion to a higher efficiency bulb.

In response to OEB staff's technical conference questions, Energy+ clarified that new additions were included and could not be separated from total billed demand. Energy+ explained that it was to the utility's detriment as lower savings were claimed with new additions included.[124]

OEB staff submits that the granularity of the data filed in this LRAMVA application is consistent with the data included in other recent LRAMVA applications that included lost revenue recovery from street light upgrades.[125] OEB staff submits the street light demand savings included in Energy+'s LRAMVA balance are appropriately calculated.

### b. Group 2 Deferral and Variance Accounts

### Disposition of Group 2 DVA Balances on a Harmonized Basis

#### *Background*

Energy+ has proposed to harmonize its 2019 distribution rates. Consistent with that request, Energy+ has also proposed to recover the December 31, 2017 balances[126] of its Group 2 Deferral and Variance Accounts (DVA) on a harmonized basis, over a one-year period. The Parties did not settle on these Group 2 DVA account balances as part of the December 12, 2018 settlement proposal for this proceeding.

The following table summarizes Energy+'s December 31, 2017 Group 2 DVA account balances by account and rate zone:

[124] Responses to Technical Conference Undertakings, JTC1.7.
[125] Examples from 2019 IRM rate applications include: EB-2018-0072 (Veridian Connections); EB-2018-0024 (Entegrus Powerlines); EB-2018-0065 (Rideau St. Lawrence).
[126] All Group 2 DVA Account balances being sought for disposition are as of December 31, 2017, except for both Accounts 1575 and 1576 which both include a forecasted amount for the bridge year 2018.

**Table 4. Summary of Group 2 DVA Balances**

| Account # | Description | CND Rate Zone | BCP Rate Zone | Total Balance |
|---|---|---|---|---|
| 1508 | Other Regulatory Assets - Sub-Account – Deferred IFRS Transition Costs | $25,494 | $0 | **$25,494** |
| 1508 | Other Regulatory Assets - Sub-Account – Financial Assistance Payment and Recovery Variance – Ontario Clean Energy Benefit Act | ($239) | $0 | **($239)** |
| 1508 | Other Regulatory Assets - Sub-Account - Monthly Bills | $416,346 | $0 | **$416,346** |
| 1508 | Other Regulatory Assets - Sub-Account - OEB Cost Assessment | $174,262 | $0 | **$174,262** |
| 1518 | Retail Cost Variance Account - Retail | $199,083 | ($56,616) | **$142,467** |
| 1548 | Retail Cost Variance Account - STR | $3,446 | ($866) | **$2,580** |
| 1555 | Smart Meter Capital and Recovery Offset Variance – Subaccount - Capital | $95,898 | $0 | **$95,898** |
| 1555 | Smart Meter Capital and Recovery Offset Variance – Subaccount – Stranded Meter Costs | $0 | $107,068 | **$107,068** |

| Account # | Description | CND Rate Zone | BCP Rate Zone | Total Balance |
|---|---|---|---|---|
| 1557 | Meter Cost Deferral Account (MIST Meters) | $150,431 | $28,069 | **$178,500** |
| 1568 | LRAM Variance Account | $1,177,449 | $368,322 | **$1,545,771** |
| 1572 | Extra-Ordinary Event Costs | ($5,857) | $0 | **($5,857)** |
| 1575 | IFRS-CGAAP Transition PP&E Amounts Balance + Return Component | $1,800,716 | $107,553 | **$1,908,269** |
| 1576 | Accounting Changes Under CGAAP Balance + Return Component | $0 | ($2,456,018) | **($2,456,018)** |
| | **TOTAL GROUP 2 DVA ACCOUNT BALANCES** | **$4,037,029** | **($1,902,488)** | **$2,134,541** |

Energy+ has confirmed that it has followed the guidance provided in the Accounting Procedures Handbook for recording amounts in the DVA accounts. The above account balances reconcile with Energy+'s December 31, 2017 *Reporting and Recordkeeping Requirements (RRR)* filing and audited financial statements, except for those accounts that have been adjusted during the proceeding.[127] Energy+ has calculated interest on the principal balances of the DVAs using the OEB's prescribed quarterly rates.

***OEB Staff Submission***

OEB staff has no concerns with the December 31, 2017 Group 2 DVA balances as presented in the above table, with the exception of the balances in Account 1575 *IFRS-CGAAP Transition PP&E Amounts Balance + Return Component* and 1576 *Accounting Changes Under CGAAP Balance + Return Component*. In both

[127] Accounts 1508, Sub-Account – Monthly Billing and Accounts 1568 LRAM have been adjusted during the current proceeding and therefore will not align to the RRR filing and audited financial statements. In addition, Accounts 1575 and 1576 include a projected amount for 2018.

cases, the account balances have been projected up to the end of 2018 as both accounts will no longer be required upon rebasing.

OEB staff notes that the estimates used to project the 2018 closing balances of each of these accounts were based on information that was available at the time the application was initially prepared and filed.[128] OEB staff submits that the audited 2018 balances for each account should now be available and therefore Energy+ should update the disposition amounts for both Accounts 1575 and 1576 to reflect the 2018 audited balances.

In regards to the calculation of interest on the principal DVA balances, Energy+ has indicated that it has projected interest up to December 31, 2018, however it had applied the Q2 2018 OEB issued rate up to the end of 2018 since that rate was the most recent at the time of filing its application. OEB staff submits that the Q3 and Q4 2018 OEB prescribed DVA rates are now available and therefore Energy+ should update its 2018 projected interest calculation using these rates. OEB staff further submits that Energy+ should also forecast interest up to the implementation date of the rate riders from this proceeding and update the disposition amounts of the Group 2 DVA accounts accordingly.

With respect to the disposition of the December 31, 2017 Group 2 DVA balances, Energy+ has proposed to dispose of these account balances on a harmonized basis irrespective of the fact that they were actually accumulated individually by service territory. OEB staff notes that DVA account balances should be disposed of based on cost causality, meaning that costs or benefits should accrue to the ratepayers that were directly responsible for incurring them. In accordance with this, OEB staff submits that Energy+ should dispose of its Group 2 DVA account balances by service territory, and not on a harmonized basis.

For example, as part of its current application, Energy+ is seeking disposition of Account 1576 *Accounting Changes Under CGAAP Balance + Return Component Group 2 DVA*, which is a refund to ratepayers of $2,456,018. The balance in this account relates entirely to the BCP service territory, however under the proposed disposition approach, this refund is shared with the ratepayers of the CND service territory. Such an outcome would not be just and reasonable to the ratepayers of the BCP service territory.

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[128] The application was filed with the OEB on April 30, 2018.

## Discontinued and New DVA Accounts

### ***Background***

*New DVA Accounts*

As part of its initial application, Energy+ requested the creation of a new deferral and variance account to track the one-time gain on sale of its 65 Dundas Street East facility. This facility was acquired as part of the acquisition of the former BCP. The sale of the property occurred in April 2018 and Energy+ was proposing to return a gain of $402,807 to ratepayers as part of its current application.[129] Energy+ also submitted a draft accounting order for the proposed new account as part of the responses provided to OEB staff interrogatories.[130]

In the settlement proposal, the Parties agreed that Energy+ should withdraw its current proposal to dispose of the gain arising from the sale of the 65 Dundas Street East property on the basis that the gain should be considered together with the incremental costs associated with the transition to the new Garden Avenue facility.[131]

*Discontinued DVA Accounts*

Energy+ has proposed to discontinue the following Group 2 DVA Account Balances:[132]

1508 Other Regulatory Asset – Sub-Account – Deferred IFRS Transition Costs

1557 Meter Cost Deferral Account (MIST Meters)

1572 Extra-Ordinary Event Costs

1575 IFRS-CGAAP Transition PP&E Amounts Balance

1576 Accounting Changes under CGAAP

### ***OEB Staff Submission***

Although the Parties agreed that the gain on the 65 Dundas Street East property will be disposed of at a later date, OEB staff submits that a new DVA account to track this gain would still be required, and would need to be approved in the

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[129] Exhibit 9.3.4 and Response to OEB Staff IR 9-Staff-103.
[130] *Ibid.*
[131] Settlement Proposal, December 12, 2018, page 17.
[132] Exhibit 9.3.5, Table 9-20 summarizes the accounts that Energy+ is seeking to discontinue.

current application. OEB staff has no concerns with the draft accounting order filed by Energy+ in response to 9-Staff-103, and supports Energy+' proposal to create the new DVA account 1508 *Other Regulatory Asset – Sub-Account – Gain on Sale.*

In regards to Energy+'s proposal to discontinue certain Group 2 DVA accounts, OEB staff has no concerns with the proposal, except for the following:

With respect to the proposal to discontinue use of Accounts 1575 *IFRS-CGAAP Transition PP&E Amounts Balance* and 1576 *Accounting Changes under CGAAP*, as noted in the previous section of this submission, Energy+ has projected these account balances up to the end of 2018. Provided that the applicant is able to update the proposed disposition amounts for these accounts with the 2018 audited balances, then OEB staff would have no concerns with Energy+'s proposal to discontinue use of these accounts. However, in the event that audited 2018 balances are not available and the accounts continue to include the projected 2018 balances, then OEB staff submits that the accounts should remain open to track the actual 2018 transactions. Any material residual balance in the account compared to what was approved as part of the current application should be brought to the OEB for disposition at the next cost based rate application.

Account 1557 *Meter Cost Deferral Account – MIST Meters* is used to record the costs associated with the installation of new MIST Meters for general service customers with a monthly demand greater than 50kW. Energy+ has indicated that it has a plan to install the MIST meters from 2017 to 2019 in order to be compliant by 2020. Energy+ has further indicated that the current balance in the account represents the installation costs incurred during 2017.[133] OEB staff is not clear as to why Energy+ would be seeking to discontinue this account when it appears that the related work is yet to be completed and that further costs are to be incurred in 2018 and 2019. OEB staff submits that Energy+ should clarify its position with respect to this account as part of its reply submission.

[133] Exhibit 9.3.3, page 34 of 80.

## VII. Issue 3.1 Load Forecast

### *Background*

To account for the proposed standby charge, Energy+ made the following adjustments to the load forecast:

- For the existing LDG in the Large Use class, Energy+ proposed to increase the 2019 kW forecast for the class by 30,443 kW to reflect the proposed standby contract capacity.
- For new LDG that is expected to go into service in 2018 and 2019, Energy+ proposed to reduce the CDM savings associated with the new LDG.

### *OEB Staff Submission*

OEB staff submits that adjustments to the load forecast and the resulting billing determinants are appropriate if the OEB approves Energy+'s standby charge proposal. Energy+ should remove these adjustments if the OEB determines not to implement a standby charge to LDG in this proceeding.

OEB staff notes that the OEB's determination on standby charge could also affect the 2019 LRAMVA threshold since it is related to the 2019 CDM adjustment.

*All of which is respectfully submitted*