Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

December 6, 2019

Christine E. Long
Registrar and Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
BoardSec@oeb.ca

Dear Ms. Long:

Re: Energy+ Inc. (Energy+)
Application for 2020 Electricity Distribution Rates
OEB Staff Submission
Ontario Energy Board File Number: EB-2019-0031

In accordance with Procedural Order No. 2, please find attached OEB staff's submission in the above proceeding.

Energy+ is reminded that its reply submission is due on December 20, 2019.

Yours truly,

Original Signed By

Jerry Wang
Analyst
Electricity Distribution – Major Rate Applications & Consolidations

Encl.

ONTARIO ENERGY BOARD

STAFF SUBMISSION

2020 ELECTRICITY DISTRIBUTION RATES

Energy+ Inc.

EB-2019-0031

December 6, 2019

Introduction

Energy+ Inc. (Energy+) filed an incentive rate-setting mechanism (IRM) application with the Ontario Energy Board (OEB) on August 26, 2019 under section 78 of the *Ontario Energy Board Act*, *1998* (OEB Act) seeking approval for changes to its electricity distribution rates to be effective January 1, 2020.

Brantford Power Inc. (Brantford Power) filed an IRM application with the OEB on August 12, 2019 under section 78 of the OEB Act seeking approval for changes to its electricity distribution rates to be effective January 1, 2020.

In Procedural Order No. 1 issued October 4, 2019, the OEB decided that the two applications would be heard together as a combined hearing due to common elements and for regulatory efficiency. The purpose of this document is to provide OEB staff's submissions specific to its review of Energy+'s application.

Consistent with the Chapter 3 Filing Requirements,[1] Energy+ applied the Price Cap IR adjustment factor to adjust the monthly service charge and volumetric distribution rate during the incentive rate-setting years. OEB staff has no concerns with Energy+'s proposed price cap adjustment.

Energy+ is in the fifth and final year towards a fully fixed monthly distribution charge. OEB staff submits that Energy+ has demonstrated that no rate mitigation is required.

Energy+ requested an update to its Retail Transmission Service Rates (RTSRs) to recover the wholesale transmission rates charged by the Independent Electricity System Operator (IESO) and its host distributors, Brantford Power and Hydro One Networks Inc. OEB staff has no concerns with Energy+'s requested adjustments to its RTSRs.

As a result of the new inflation factor issued by the OEB for 2020,[2] OEB staff updated Energy+'s models (the rate generator model and the ICM model) to reflect the 2% inflation factor. OEB staff submits that Energy+ should use the updated models included as part of this submission if any further updates are required.

[1] Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 Incentive Rate-Setting Applications, July 12, 2018
[2] Issued on October 31, 2019

OEB staff makes detailed submissions on the following:

- Group 1 Deferral and Variance Accounts
- Lost Revenues Adjustment Mechanism Variance Account (LRAMVA)
- New Deferral Account for Lost Revenues
- Incremental Capital Module (ICM)
- Gain on Sale of Paris Facility
- Large Use Class Fixed Charge
- Foregone Revenue

Group 1 Deferral and Variance Accounts

Energy+ requested disposition of its December 31, 2018 Group 1 deferral and variance accounts (DVAs) balances on an interim basis. Energy+'s 2018 Group 1 balances meet the $0.001/kWh threshold for disposition.

Energy+ indicated it implemented the new accounting guidance[3] for Accounts 1588 and 1589 by August 31, 2019. Energy+ implemented a revision to its accounting processes as a result of the new accounting guidance.[4] Energy+ has also reviewed its 2018 balances in the context of the new accounting guidance and has identified adjustments to the balances. Energy+ used the OEB's Illustrative Commodity Model[5] to determine the expected 2018 balances,[6] then adjusted its 2018 balances in the general ledger to the expected balances. OEB staff submits that this is a reasonable approach to determine adjustments to the 2018 balances.

Energy+ disposed its 2017 Group 1 accounts on an interim basis in its 2019 cost of service rate application.[7] Energy+ indicated it has not had a chance to review its 2017 balance and commits to providing the results of the review in its 2021 IRM application.[8] As a result, Energy+ has not requested final disposition of its 2017 balances. OEB staff agrees that the 2017 balances should not be disposed on a final basis and the 2018 balances should only be disposed on an interim basis so that the continuity of any future changes will be appropriately captured.

[3] Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589, February 21, 2019
[4] IRM Application, p. 23-24
[5] Model from Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589, February 21, 2019
[6] IRR E-Staff-36
[7] EB-2018-0028
[8] IRR E-Staff-35

Lost Revenues Adjustment Mechanism Variance Account

Introduction

Energy+ applied to dispose of a LRAMVA debit balance of $762,915 for lost revenues up to December 31, 2018 (including carrying charges projected to December 31, 2019) over a 12-month period. As Energy+ maintained separate distribution rates for each of the former utilities until the 2019 cost of service[9] rate year, Energy+ continues to file separate LRAMVA claims for each of its service territories in this application.

LRAMVA Request

The LRAMVA debit balance of $762,915 includes lost revenue amounts in 2018 from the Cambridge and North Dumfries Hydro (CND) service territory (of $539,527) and Brant County Power (BCP) service territory (of $223,388).

In the CND service territory, the LRAMVA debit balance of $539,527 consists of lost revenues in 2018 from Conservation and Demand Management (CDM) programs delivered during the 2011 to 2018 period, and associated carrying charges projected to December 31, 2019. Actual savings were compared against forecast savings of 39,520,173 kWh as set out in the former CND's 2014 cost of service proceeding.[10]

In the BCP service territory, the LRAMVA debit balance of $223,388 consists of lost revenues in 2018 from CDM programs delivered during the 2011 to 2018 period, and associated carrying charges projected to December 31, 2019. Actual savings were compared against forecast savings of 1,494,000 kWh as set out in the former BCP's 2011 cost of service proceeding.[11]

Supporting Documents

In accordance with the *Addendum to the Filing Requirements for Electricity Rate Applications,*[12] Energy+ filed the 2019 Participation and Cost Report in support of the 2018 unverified savings and adjustments to prior year savings. In addition, Energy+ filed

[9] EB-2018-0028, Decision and Order, June 13, 2019, Corrected June 18, 2019
[10] EB-2013-0116, Decision and Order, August 14, 2014
[11] EB-2010-0125, Decision and Order, May 9, 2011
[12] *Addendum to the Filing Requirements for Electricity Rate Applications for 2020 Rate Applications,* issued July 15, 2019

the 2017 Final Verified Results Report in support of the savings persistence from 2011 to 2017 programs in 2018 included in the LRAMVA balance.

Energy+ continues to use its utility-derived allocations to split out savings by service territory, as the IESO no longer produces utility-specific CDM Results Reports following the amalgamation of CND and BCP in 2016.

Street Lighting and Combined Heat and Power (CHP) Projects

As part of 2018 lost revenues, Energy+ included the savings persistence from street light upgrades in 2016 and a CHP project from Toyota's participation in the IESO's Process and Systems Upgrade Initiative in 2015.

Staff Submission

OEB staff submits that Energy+'s LRAMVA balance has been calculated in accordance with the OEB's CDM Guidelines and OEB policy. OEB staff supports the disposition of the LRAMVA debit balance of $762,915, as filed, based on the amounts set out in Table 1 below.

Table 1 - LRAMVA Balance for Disposition

Account Name	Account Number	Actual CDM Savings ($) A	Forecasted CDM Savings ($) B	Carrying Charges ($) C	Total Claim ($) D=(A-B)+C
LRAMVA – CND service territory	1568	$910,984	$388,004	$16,547	$539,527
LRAMVA – BCP service territory	1568	$231,647	$15,110	$6,851	$223,388
LRAMVA – Total	**1568**	**$1,142,631**	**$403,114**	**$23,398**	**$762,915**

OEB staff discusses the following topics in more detail:

- No Service Territory Specific CDM Results
- LRAMVA Threshold
- Demand Savings from CHP Project and Street Lighting

No Service Territory Specific CDM Results

Energy+ indicates that the CDM savings and breakdown of the savings by service territory remain unchanged from its previous LRAMVA filing, with the exception of the adjustments made to 2018 balances.[13]

OEB staff has no issue with the allocation of savings from 2011 to 2016 by service territory and the breakdown of savings by rate class in each service territory. OEB staff confirms that the service territory and rate class allocation of CDM savings from 2011 to 2016 have not changed from its last approved LRAMVA filing (in the 2019 cost of service proceeding). This has resulted in the same persisting savings claimed from 2011 to 2016 CDM programs in 2018, as in its previous application.

OEB staff submits that the breakdown of 2017 and 2018 savings by service territory and rate classes, as well as persisting 2017 savings in 2018, are reasonable. The allocation of lost revenues, by service area and rate class, continue to correspond with the savings achieved by service area and rate class using project-specific data from its monthly submissions to the IESO.[14] Consistent with its previously approved LRAMVA filing, Energy+ continues to apportion CDM savings based on the relative consumption of its service territories, in the event there was no data on CDM savings by service territory to allocate lost revenues.

OEB staff submits that the adjustments made to 2018 balances, as noted above, reflect the adjustments to 2017 program savings identified in the 2019 Participation and Cost Report.

LRAMVA Thresholds

Energy+ applied the LRAMVA thresholds approved for each of the former utilities as the basis to compare forecast savings against actual savings in each service area. OEB staff submits that Energy+ has correctly applied the LRAMVA thresholds for each service territory that were established in the former utility’s cost of service proceedings.

As Energy+ has now been approved a 2019 LRAMVA threshold in its 2019 cost of service proceeding, OEB staff submits that there is no longer a need to file separate lost revenue claims by rate zone in future rate applications.

Demand Savings from CHP Project and Street Lighting

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[13] Tab 3-a of LRAMVA workforms for the CND and BCP service territories
[14] Monthly submission data on CDM savings to the IESO, as filed in Energy+ Supplementary Data file

As part of the LRAMVA balance, Energy+ included $174,340 from the CHP project (32% of the LRAMVA claim in the CND service territory) and $78,410 from street light upgrades in Brant County (35% of the LRAMVA claim in the BCP service territory).

i. CHP Project

The OEB approved the methodology to calculate demand savings from the CHP project in Energy+'s 2019 cost of service proceeding.[15] In claiming 2018 persistence from the CHP project in this proceeding, Energy+ states that it used actual 2018 metered data from the customer's CHP generator and Energy+'s supply, consistent with the methodology approved in its 2019 cost of service proceeding.[16]

In response to OEB staff interrogatories, Energy+ noted that the true lost revenue impact has been captured with its utility-specific data, as the verified savings calculations from the Measurement and Verification Report do not take into consideration coincidence with Energy+ supply.[17]

OEB staff confirms that Energy+'s calculation of CHP savings is consistent with the methodology approved in its 2019 cost of service proceeding. OEB staff submits that Energy+ filed an update to the hourly peak data[18] on the grid and facility peaks in 2018 to derive the highest peaks in the month used to determine the baseline and actual load billed with the CHP project. The difference between the baseline and actual load in 2018 resulted in lost revenues to Energy+ due to the CHP project.

Furthermore, the net-to-gross assumption (of 1.001) used to convert gross savings to net savings is consistent with the IESO's 2017 program evaluation results and aligns with the value approved in its previous LRAMVA filing.

ii. Street Lighting Project

Energy+ states that its 2018 persistence savings for street light upgrades was approved in its 2019 cost of service proceeding.[19] OEB staff confirms that the same data and methodology, which was included for approval with its previous LRAMVA filing, has

[15] EB-2018-0028, Decision and Order, June 13, 2019, Corrected June 18, 2019
[16] IRM Application, pp. 25-26
[17] IRR E-Staff-66 a)
[18] Confidential data file submitted in response to E-Staff-66 b)
[19] IRM Application, p. 25

been used in this proceeding to support the 2018 persistence savings claimed from street lighting upgrades.

OEB staff supports the disposition of lost revenues from the CHP project and street lighting upgrades.

OEB staff supports the disposition of the total LRAMVA debit balance of $762,915 as filed.

New Deferral Account for Lost Revenues

Energy+ requested the establishment of an account to record lost revenues relating to the Notification Charge, effective July 1, 2019.[20] OEB staff submits that the proposed account meets the eligibility criteria of causation, materiality and prudence as specified in the OEB's *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications.*

In the OEB's March 14, 2019 notice to amend codes and a rule,[21] the OEB eliminated the Collection of Account charge effective July 1, 2019. In the same notice, the OEB indicated that a distributor could apply for an account to track the impact of eliminating non-payment related charges with evidence demonstrating that the account would meet the eligibility criteria as set out in the *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications.* In OEB staff's Bulletin,[22] OEB staff expressed its view that the Notification Charge cannot be applied to collection activities similar to the Collection of Account charge.

In its application, Energy+ discussed the causation, materiality and prudence of the account. Regarding causation, Energy+ indicated that it reached an approved settlement proposal on its revenue requirement (including revenue offsets) in its 2019 cost of service rate application in early December 2018,[23] prior to the OEB's notice to amend codes and a rule issued on December 18, 2018.[24] OEB staff acknowledges that Energy+ would sustain lost revenues from the Notification Charge as a result of the timing of its 2019 approved settlement proposal and the OEB's proposal to eliminate charges related to collection of accounts.

[20] IRR E-Staff-63
[21] Notice of Amendments to Codes and a Rule, EB-2017-0183, March 14, 2019
[22] Re: Application of "Notification Charges" to Collection Activities, August 8, 2019
[23] Settlement agreement was filed on December 12, 2019
[24] IRR E-Staff-63

Regarding materiality, Energy+ indicated its materiality threshold is $175,000.[25] The account Energy+ proposed will record lost revenues based on the number of notices issued at the approved Notification Charge on its Schedule of Rates and Tariff. Annual lost revenues is expected to be the approved revenue offset for this charge of $278,000.[26] Energy+'s actual lost revenues from 2015 to 2018 ranged from $257,415 to $411,075 annually.[27] OEB staff submits that the amount of lost revenues to be recorded in the account would likely be material to Energy+.

That said, OEB staff does not understand why the number of notices issued is so large. At $15 per notice, Energy+ would have to issue over 18,000 notices each year to collect $278,000. While OEB staff accepts that this is the amount that underpins current base rates, it does appear to be an unusually high number, especially if one considers that the annual revenue from this charge has peaked to over $400,000. This peak number represents over 27,000 notices issued in one year for a customer base of just over 65,000.

In its response to an interrogatory, Energy+ stated it did not consider basing the account on the number of actual notices issued, capped at the approved revenue offset of $278,000. Energy+ explained that it has experienced fluctuations in the number of notices issued and it incurs operating costs for the issuance of the notices. Capping lost revenues in years that are above the approved revenue offset amount does not allow Energy+ to recover costs incurred on the notices issued above and beyond what was estimated.[28] OEB staff notes that Energy+'s costs of producing and issuing each notice is $4.46.[29] OEB staff submits that the Notification Charge is intended to allow a distributor to recover its costs of the activity.

OEB staff submits that the above information may be sufficient for the OEB to cap the variance account to a maximum of $278,000. OEB staff also submits that at the time the account (if approved) is proposed for disposition, Energy+ should provide evidence demonstrating prudence, including providing support for the number of notices issued.

In its draft accounting order filed with the application, Energy+ states that the account would be reduced by amounts recovered from customers following the approval of the

[25] *Ibid*
[26] *Ibid*
[27] *Ibid*
[28] *Ibid*
[29] $15 Notification Charge – $4.46 cost per notice per Interrogatory Response E-Staff-63

disposition of the account.[30] In the event that the OEB approves disposition of the balance in the proposed account, OEB staff submits that similar to other DVAs, the balance should be transferred to Account 1595 Disposition and Recovery/Refund of Regulatory Balances and rate rider amounts received from customers should be recorded in Account 1595 instead of the proposed account. OEB staff does not see a reason for the treatment of this account to deviate from the normal treatment of any other DVA upon disposition.

Incremental Capital Module

Introduction

Energy+ requested to recover, through the ICM mechanism, $3.48 million in incremental capital associated with the capital lease for a new facility shared with Brantford Power at 150 Savannah Oaks. The new facility will serve as Energy+'s new operations centre for its BCP service territory. The resulting incremental annual revenue requirement is $0.37 million. Based on OEB staff's analysis in the sections below, OEB staff submits that Energy+'s ICM request satisfies the ICM criteria of materiality, need and prudence and should be approved subject to certain revisions.

Energy+ currently serves two non-contiguous service territories: the CND service territory and the BCP service territory. Energy+ began serving the BCP service territory when it acquired the former Brant County Power Inc. in 2014.[31] As part of the acquisition, Energy+ acquired the former Brant County Power Inc.'s administration and operations facility located in Paris, Ontario (Paris facility) and continued to use the facility to serve its BCP service territory customers. Energy+ also has two facilities located in its CND service territory, one of which serves as its corporate head office.

In 2017, Energy+ determined that the Paris facility was no longer efficient or optimal for its needs.[32] Because Energy+ had relocated 14 administrative employees from the Paris facility to its corporate headquarters in Cambridge in 2016, the Paris facility became essentially an operations centre leaving the administration space underutilized.[33] At the same time, the Paris facility had insufficient operational space to accommodate Energy+'s needs in the future as the utility experienced growth.[34]

[30] IRR E-Staff-63
[31] EB-2014-0217 / EB-2014-0223
[32] IRM Application, p. 48
[33] *Ibid*
[34] *Ibid*

Energy+ also had growing concerns about the condition of the building due to its age, including problems such as roof leaks and mold contamination.[35] As Energy+ re-evaluated its continued use of the Paris facility, Brantford Power came forward with an opportunity for the two utilities to occupy a shared facility. Brantford Power was in the process of finding a new facility to serve as its administration and operations facility and offered to lease a portion of the new facility to Energy+. Energy+ accepted this proposal and signed a Memorandum of Understanding (MOU) with Brantford Power in late 2017. The MOU set out Energy+'s commitment to enter into a long-term lease agreement for space and shared services at Brantford Power's new facility, and also a termination fee of $635,000 payable to Brantford Power if Energy+ terminates its commitment.[36]

Subsequent to the MOU, Energy+ sold the Paris facility in 2018, but continued to occupy it as part of a leaseback arrangement with the new owner of the facility. Per the terms of the arrangement, Energy+ can continue to lease space at the Paris facility for five years from the date of sale.[37] Energy+ expects to terminate the lease in 2020 once it has finished relocating its Brant County operations centre to the 150 Savannah Oaks facility. Energy+ has proposed to refund to customers 100% of the gain on sale of the Paris facility.

Brantford Power made progress throughout 2017 and 2018 in the search for a new facility and ultimately narrowed the search to two properties; 150 Savannah Oaks and 79 Garden Avenue.[38] At the time of Energy+'s 2019 cost of service application, Brantford Power had decided to proceed with the 79 Garden Avenue location and issued a Request for Proposal (RFP) for a builder to construct the new facility at 79 Garden Avenue.[39] Energy+ included its portion of costs associated with the new facility at 79 Garden Avenue as an Advanced Capital Module (ACM) request in its cost of service application. In the approved settlement proposal of Energy+'s 2019 cost of service application, Energy+ agreed to withdraw its ACM request and instead apply for an ICM (in this application). This arrangement was so that Energy+'s ICM application could be heard by the OEB concurrent with Brantford Power's ICM application to recover capital for the same facility.[40]

Brantford Power did not ultimately receive any bids on its RFP for the 79 Garden Ave.

[35] *Ibid*
[36] IRM Application, pp. 37, 49
[37] IRM Application, p. 36
[38] For further details on the timeline of Brantford Power's search for a new facility, please refer to OEB staff's submission on Brantford Power's ICM request, EB-2019-0022.
[39] EB-2018-0028
[40] EB-2018-0028, Settlement Proposal, December 12, 2018, p. 17

facility, and received feedback that the cap of $27 million it had set for bids on the RFP was too low.[41] Rather than increase the cap, Brantford Power opted instead to pursue the other property it identified in its search, 150 Savannah Oaks. Energy+ signed an amended MOU in May of 2019 to confirm its support of the shared facility project.[42] Energy+'s current ICM request is for the 150 Savannah Oaks facility.

Energy+ and Brantford Power will not be the only tenants in the 150 Savannah Oaks facility. A potential unidentified "third tenant" will also be leasing portions of the facility. The total cost of the new facility (i.e. the sum of the purchase price and renovation/construction costs) has been allocated proportionally to each tenant based on the square footage of space each occupant will occupy. Energy+'s ICM request includes only costs associated with space that has been allocated for Energy+'s exclusive use. There are also shared services and shared space between the occupants of the new facility – Energy+ will pay this portion of costs by entering into a Shared Service Agreement (SSA) with Brantford Power. Energy+ has not requested to recover the costs associated with the SSA in this application and has indicated that its shareholders will bear the costs until its next rebasing application.

Materiality

The *Report of the OEB: New Policy Options for Funding of Capital Investments: The Advanced Capital Module* (ACM Report) states that distributors must meet an OEB-defined materiality threshold and a project-specific materiality threshold.[43]

The ACM Report explains materiality as follows:

> 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 project

[41] EB-2019-0022, IRM Attachment A, p. 22
[42] IRM Application, Appendix F, Exhibit II
[43] EB-2014-0219, Report of the OEB: New Policy Options for Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, pp. 16-17

expenditure over and above the OEB-defined threshold calculation is expected to be absorbed within the total capital budget.[44]

The OEB-defined materiality threshold is defined in Chapter 3 of the Filing Requirements for Distribution Rate Applications. It represents a distributor's financial capacities underpinned by existing rates, including growth and a 10% dead band. The equation used to calculate the materiality threshold is as follows:

$$Threshold\,Value\,(\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + X\%$$

Where: RB = rate base included in base rates ($)
d = depreciation expense included in base rates ($)
g = distribution revenue change from load growth (%)
PCI = price cap index
n = number of years since the cost of service rebasing
X = dead band which is currently set at 10%

In the application as originally filed, Energy+ used a price cap index of 1.2% as a placeholder, since the price cap index for 2020 was not yet available. This was based on an inflation factor of 1.50% less a productivity factor of 0.00% and a stretch factor of 0.30%. Using the formula above, Energy+ stated it had calculated its materiality threshold to be $6,155,872.[45] OEB staff submits that the inflation factor for 2020 has since been updated to be 2% with the stretch factor remaining at 0.30%.[46] OEB staff calculates Energy+'s price cap index now to be 1.70%. OEB staff has recalculated Energy+'s materiality threshold and submits that it be revised to $7,528,202. OEB staff expects that Energy+ would be able to finance capital expenditures of this amount through its existing rates.

In the application as originally filed, Energy+ requested to recover $4,395,862 through the ICM for the costs associated with its new operations facility.[47] Brantford Power provided Energy+ with this number by allocating the portion of costs associated with Energy+'s exclusive space.[48] During the interrogatory process for Energy+ and Brantford Power, OEB staff and intervenors asked Brantford Power to provide an

[44] ACM Report, p. 17
[45] IRM Application, p. 34
[46] Inflation factor for 2020 updated on October 31, 2019
[47] IRM Application, p. 34
[48] IRM Application, p. 44; IRM Application, Appendix F, Exhibit IV

updated Class C estimate for the estimated costs of the new facility.[49] Brantford Power did not have the Class C estimate available at the time of the interrogatory responses, but provided the information in a separate letter filed with the OEB on November 26, 2019.[50] As part of the update, the costs of the new facility have been updated including Energy+'s allocated costs for its exclusive space. The cost allocated to Energy+ has been reduced to $3,557,067.[51] To more accurately reflect lease accounting and tax treatment of the capital lease on the new facility, Energy+ revised the ICM model and provided a revised ICM request of $3,482,492, which is a reduction from $3,557,067.[52] OEB staff takes no issue with Energy+'s methodology and calculated amount of $3,482,492.

Energy+ stated its forecasted total capital for 2020 to be $17,976,000, which is unchanged from its 2020 forecast set out in its Distribution System Plan supporting its 2019 cost of service application.[53] In order to reflect the lowered costs associated with the new facility above, OEB staff calculates Energy+'s 2020 revised forecast capital spending to be $17,062,630.[54] OEB staff submits that based on the revised materiality threshold above, and the revised forecast capital spending envelope, the maximum eligible incremental capital amount available to Energy+ through this ICM for 2020 rates is $9,534,428. OEB staff notes that Energy+'s ICM request of $3,482,492 is within the maximum eligible incremental capital amount.

With regard to the project-specific materiality threshold, projects that are minor expenditures in comparison to the overall capital budget of the distributor are not eligible for ICM treatment. OEB staff submits that the incremental capital Energy+ requested for the new facility is 21% of its total 2020 budget.[55] OEB staff submits this project represents a significant capital expenditure for Energy+ and therefore satisfies the project-specific materiality threshold.

[49] PO No. 1 combined Brantford Power's and Energy+'s interrogatory process; see B-Staff-20 a) and SEC-BPI-10
[50] EB-2019-0022, Interrogatory Responses – Class C Updates, November 26, 2019
[51] *Ibid*, p. 2
[52] "EnergyPlus_2020_ICM_Model_Class_C_Update.xlsx", filed on December 2, 2019; for a description of Energy+'s lease accounting and tax treatment methodology, see IRR E-Staff-60.
[53] IRM Application, p. 34
[54] OEB staff calculated this number by taking Energy+'s original 2020 capital forecast and subtracting the original cost of the new facility of $4,395,862 and adding the new cost of $3,482,492.
[55] ACM/ICM Model, tab 9b; Brantford Power's total cost for the new facility is $16,195,396 out of its total 2020 capital expenditures of $20,720,878.

Need

The OEB describes need in the ACM Report 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.[56]

Under the Means Test, if a distributor's regulated return on equity (ROE) exceeds 300 basis points above the deemed ROE embedded in the distributor's rates, then the funding for any incremental capital project will not be allowed. Energy+ stated that its current deemed ROE was set at 8.98% during its 2019 cost of service application and that it is not forecasted to exceed 8.98% for 2019.[57] Prior to 2019, Energy+'s deemed ROE was 9.36% as set during its 2014 cost of service rebasing.[58] Energy+ indicated that its ROE was not in excess of 300 basis points from 9.36% for the years 2015-2018.[59] OEB staff submits that Energy+ passes the Means Test.

OEB staff notes that no amounts associated with the new facility were included in Energy+'s rate base at the time of the last rebasing in 2019.[60] Energy+ included the new facility project as an ACM request, but ultimately withdrew the ACM request. OEB staff further notes that the amounts requested for ICM treatment relate strictly to costs associated with Energy+'s allocated exclusive space in the new 150 Savannah Oaks facility. OEB staff submits Energy+'s ICM request represents a discrete project and is outside of the base upon which rates were derived.

Prudence

The OEB describes the prudence threshold in the ACM Report 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.[61]

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[56] ACM Report, p. 17
[57] IRM Application, p. 32
[58] EB-2013-0116
[59] *Ibid*
[60] EB-2018-0028
[61] ACM Report, p. 17

The two service areas that Energy+ serves in Cambridge and Brant County are not contiguous. Energy+ currently retains a team of operations staff in the Paris facility to service customers in the BCP service territory. Energy+ explained that maintaining an operations centre in the BCP service territory is necessary to provide customers in Brant County with adequate service due to the travel time between Cambridge and Brant County.[62] Additionally, Energy+ noted that it uses the Paris facility to store materials and equipment for work in Brant County.[63] As an indication of the distance between Cambridge and Brant County, Energy+ stated that the travel time between Energy+'s operations center in Cambridge and the new operations centre at 150 Savannah Oaks is approximately 30-35 minutes.[64] OEB staff agrees with Energy+ that it is prudent and necessary to maintain an operations centre in Brant County. Given the 30-35 minute estimated travel times between the two operations centres, OEB staff submits that Brant County customers would likely experience longer response times from Energy+'s operations crews if there is not an operations centre in Brant County.

As discussed previously in the introduction section, Energy+ found the current Paris facility inadequate for its needs and decided to relocate to a new operations centre in Brant County. Energy+ evaluated three options for a new operations centre. The first option Energy+ considered is to renovate or rebuild the Paris facility to address aging infrastructure and space concerns. Energy+ did not choose this option as it would not provide the same opportunities for synergies and efficiencies through sharing a facility with Brantford Power (the second option), and it would not provide any gain on sale of the Paris facility.[65]

The second option Energy+ considered, and ultimately chose to pursue, is to lease portions of a facility shared with Brantford Power. Energy+ noted a number of advantages in sharing a facility with Brantford Power including:[66]

- The location selected by Brantford Power is ideal, has good access to arterial roads and is only 5 km away from the current Paris facility.
- Opportunity to share with Brantford Power the costs of construction, which are needed to right size the facility for both utilities' needs.
- Opportunities for shared services including shared inventory, warehousing, fueling stations, vehicle maintenance, and purchasing.

[62] IRM Application, p. 48
[63] *Ibid*
[64] IRR E-Staff-52
[65] IRM Application, pp. 51-52
[66] IRM Application, pp. 39; IRR E-Staff-49

- Allows for Energy+ and Brantford Power to assist each other and share resources during emergency or extreme weather events.

With regard to shared services, Brantford Power provided the example of sharing three full-time employees (FTE). Brantford Power estimated about $150,000 in savings to both Brantford Power and Energy+ through sharing three FTEs.[67] The costs associated with these FTEs, and any savings, will be part of the SSA that Energy+ will sign with Brantford Power and reflected in rates when Energy+ next rebases.

The third option Energy+ considered is to acquire or lease a new standalone facility, separate from Brantford Power. To estimate the cost of this option, Energy+ used the cost estimate Brantford Power had conducted on the 79 Garden Avenue facility as a proxy.[68] During the time when Brantford Power pursued the 79 Garden Avenue facility, it had calculated Energy+'s portion of allocated costs to be $6.77 million.[69] For this option, Energy+ assumed that any facility it could acquire or lease would cost the same as 79 Garden Avenue (i.e. $6.77 million).[70] Energy+ did not pursue this option as it would be more expensive and not provide the same synergies as sharing a facility with Brantford Power.[71]

OEB staff agrees with Energy+ that option one of rebuilding or renovating the existing Paris facility would be prohibitively expensive in comparison to the other options.[72] OEB staff notes that, to meet Energy+ requirements, Energy+ would need to renovate the Paris facility to provide additional operational space and address concerns with aging infrastructure. Further, if Energy+ chose to rebuild the Paris facility from scratch rather than renovate, that would also incur the cost to demolish the old building.

With regard to option three, OEB staff believes Energy+ should have analyzed this option further. In OEB staff's opinion, it is not accurate or appropriate to use the cost of the 79 Garden Avenue facility as a proxy for the cost of Energy+ acquiring or leasing a standalone facility. The process of acquiring or leasing a facility provides Energy+ with an opportunity to negotiate the price, and OEB staff believes Energy+ could have potentially found properties with a price lower than $6.77 million. OEB staff submits that Energy+'s proxy of $6.77 million does not provide an accurate estimate of the true cost

[67] IRR B-Staff-14
[68] IRM Application, pp. 54-55
[69] *Ibid*
[70] *Ibid*
[71] *Ibid*
[72] IRM Application, pp. 52, 56; Energy+ estimates this option to cost approximately the same as the third option, which it notes is expensive and unfavourable relative to the 150 Savannah Oaks option.

of properties currently available on the market.

That being said, OEB staff agrees with Energy+ that a shared facility with Brantford Power provides unique opportunities to reduce costs. Energy+ and Brantford Power, being similarly sized electricity distributors, could reasonably reduce costs through economies of scale. OEB staff submits that it is reasonable to expect synergies through a shared facility, which gives it advantages over a standalone facility for Energy+. Given these reasons, OEB staff supports Energy+'s choice to pursue a shared facility with Brantford Power.

As part of its application, Energy+ provided benchmarking for its allocated costs for the 150 Savannah Oaks facility. Energy+ provided two sets of costs: the cost of the 150 Savannah Oaks facility and the combined cost of Energy+'s three facilities that are contemplated in its Overall Facilities Plan (this includes 150 Savannah Oaks as well as two facilities located in the CND service territory).[73] Energy+ argued that, for the purposes of benchmarking, it is more appropriate to benchmark the combined cost of all three facilities because each individual facility was contemplated in the context of the Overall Facilities Plan, and provides customers with the lowest price possible as a whole.[74]

OEB staff disagrees with Energy+ and submits that summing the costs of all the new facilities contemplated in its Overall Facilities Plan is not the appropriate methodology to evaluate the 150 Savannah Oaks facility. As discussed above, OEB staff agrees it is in Brant County customers' best interests to have Energy+ maintain an operations facility within the BCP service territory. Regardless of Energy+'s plans for facilities in the CND service territory, OEB staff agrees that an operations facility within Brant County would be necessary. As such, OEB submits that the need for the 150 Savannah Oaks facility is independent of Energy+'s facilities in the CND territory and should therefore be evaluated on its own merits.

OEB staff further proposes that, for benchmarking purposes, the cost of the 150 Savannah Oaks facility be reduced by the amount of gain on sale on the Paris facility being returned to customers. OEB staff believes this is appropriate because, if Energy+ chose to rebuild or renovate the Paris facility, the cost of that project would not include the cost of land (since Energy+ would already own the land).

Based on OEB staff's methodology above, for the purposes of benchmarking, OEB staff

[73] IRM Application, p. 60
[74] IRM Application, p. 59

calculates Energy+'s cost of the 150 Savannah Oaks property to be $3,145,206.[75] As part of the updated Class C estimate provided by Brantford Power on November 26, 2019, Brantford Power updated the exclusive space allocated to Energy+ to 15,679 square feet.[76] Using the updated numbers, OEB staff calculates Energy+'s capital cost per square foot to be $195.84 and square feet per employee to be 1,206.[77]

For the purposes of OEB staff's analysis here, OEB staff has benchmarked Energy+'s costs against the comparators provided by Brantford Power in its application because Brantford Power provided more examples for comparison than Energy+. Compared to the seven comparators provided by Brantford Power, Energy+'s capital cost per gross square foot is the second lowest.[78] Compared to the four comparators that were administration and operations facilities, Energy+'s square feet per employee is in the middle.[79] OEB staff submits that Energy+'s allocated space and incurred costs are reasonable and in line with similar facilities projects undertaken by other electricity distributors.

For the reasons above, OEB staff submits that the amounts incurred by Energy+ for its new operations centre at the 150 Savannah Oaks facility are prudent.

Accounting

For accounting purposes, Energy+ is treating the lease as a finance lease under IFRS 16 Leases.[80] Energy+ would recognize a right-of-use asset (i.e. capital asset to be included in rate base), which is generally calculated as the present value of the lease payments discounted at the implicit lease rate. In the MOU between Energy+ and Brantford Power, the lease payments will include the recovery of amortization, Payment in Lieu of Taxes and return on invested capital for the portion of the project that relates to Energy+'s exclusive use.[81] Although it should be similar, OEB staff notes that

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[75] $3,070,631 is derived from the $3,482,492 updated Class C estimate of Energy+'s costs as previously noted in the materiality section, less $411,861 which is the gain on sale of the Paris facility Energy+ has proposed to return to customers.
[76] EB-2019-0022, Interrogatory Responses – Class C Updates, November 26, 2019, p. 2; this is an increase from 14,229 square feet as per the originally filed application, see IRM Application, p. 44.
[77] $3,070,631 / 15,679 = 195.84 and 15,679 / 13 = 1,206.
[78] EB-2019-0022, Brantford Power's 2020 Rate Application, IRM Attachment A, p. 25; Brantford Power applied an inflationary adjustment to the historical costs of the other facilities by applying a 2% annual inflation factor.
[79] *Ibid*; Energy+ has a small portion of administration space in 150 Savannah Oaks, but otherwise, occupies mostly operations space. OEB staff does not have other purely operations facilities for comparison and has therefore used other administration and operations facilities as comparators.
[80] IRM Application, p. 46
[81] IRR E-Staff-58

Energy+'s calculation of the right-of-use asset that is requested for recovery, may not equal the capital Brantford Power has allocated Energy+ due to the variables used in the calculation of the right-of-use asset. OEB staff notes that Brantford Power allocated to Energy+ a capital amount of $3,557,067.[82] Energy+ calculated a right-of-use asset of $3,482,492.[83] OEB staff notes that the right-of-use asset Energy+ requests for recovery does not exceed the capital Brantford Power has allocated Energy+. That is, there should be no overlap in the capital requested for recovery on a total basis between Energy+ and Brantford Power.

OEB staff has noted unique ratemaking ramifications above because Energy+ is treating the new facility as a right-of-use asset under a finance lease. Therefore, if Energy+ chooses to amend or terminate its lease at any point in the future, OEB staff submits that Energy+ should make any such changes explicitly known to the OEB in future proceedings.

Gain on Sale of Paris Facility

For reasons discussed in the above ICM section, Energy+ sold its facility located in Paris, Ontario in 2018. Energy+ sold the Paris facility for $1.5 million and calculated a total gain on sale of $402,807.[84] In this application, Energy+ proposed to return to customers $411,861, which includes the $402,807 gain on sale plus $9,053 in projected interest from January 1, 2019 to December 31, 2019.[85] Energy+ proposed disposition of the amount over four years to align with the duration of the ICM rate riders.[86]

Energy+ calculated the $402,807 gain on sale amount by netting the sale price of $1.5 million against the transaction costs, remaining regulatory net book value of the facility, tax on the sale and a "fair value increase paid by former CND on Acquisition."[87] Energy+ explained that when it acquired the former Brant County Power Inc., it paid the shareholders of Brant County Power Inc. an additional $555,416 above the regulatory book value of the Paris facility.[88] This amount, which Energy+ calls the "fair value increase", is the difference between the regulatory net book value of the Paris facility

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[82] EB-2019-0022, Interrogatory Responses – Class C Updates, November 26, 2019
[83] "EnergyPlus_2020_ICM_Model_Class_C_Update.xlsx", filed on December 2, 2019
[84] IRM Application, p. 61
[85] IRR E-Staff-45
[86] IRR E-Staff-32; The ICM rate riders expire at the time of Energy+'s next rebasing, which is expected four years from now, for the 2024 rate year.
[87] IRM Application, p. 61
[88] IRR E-Staff-46

and the market value of the property at the time of the acquisition.[89]

OEB staff has no concerns with Energy+ netting out the transaction costs and including the estimated tax impact on the sale in the gain calculation. However, OEB staff does not agree with Energy+ that it is appropriate to deduct a "fair value increase" from the gain on sale proposed to be refunded to customers. The "fair value increase" represents an amount paid above the regulatory book value of the asset. In OEB staff's view, this is by definition an acquisition premium. The OEB's decision that granted approval for Energy+'s acquisition of the former Brant County Power Inc. made it clear that "[a]s indicated in the 2007 Report, it is not appropriate for the premium to find its way into future rates."[90] Furthermore the OEB reiterated its general policy on premiums on page 8 of the *Handbook to Electricity Distributor and Transmitter Consolidations* states:[91]

> If a premium has been paid above the historic value, this premium is not recoverable through distribution rates and no return can be earned on the premium. A shareholder may recover the premium over time through savings generated from efficiencies of the consolidated entity.

OEB staff notes that upon acquisition of Brant County Power Inc., the premium was recorded as a non-regulated asset in Energy+'s books. This treatment ensured that there was no return earned on the premium. As the premium was recorded as an asset, it was never expensed, and therefore, the premium was not included in the revenue requirement at that point in time. However, Energy+'s current proposal to include the premium as a reduction to the gain on sale is effectively requesting recovery of the premium through distribution rates now. OEB staff submits the premium should not be recoverable in accordance with the OEB's policy on premiums and, therefore, should not be deducted in the calculation of the gain.

Energy+ explained that it had not included the "fair value increase" into rate base or as part of the revenue requirement since the acquisition of the former Brant Count Power Inc. Energy+ further explained:

> […] it is appropriate to reduce the overall proceeds from the sale of the property by [the fair value increase] since the actual gain that has been realized on the sale of the property is computed based on the actual total costs incurred in

[89] *Ibid*; The market value of the property was based on a market valuation report provided by an independent third-party, Regional Appraisals.
[90] EB-2014-0217 / EB-2014-0223, Decision and Order, October 30, 2014, p. 5
[91] Issued January 19, 2016

> purchasing the land and building (which in the case of Energy+ is the fair market value of the property acquired at the time of the purchase of the former Brant County Power Inc.), compared to the net proceeds received for the sale of the property.[92]

OEB staff disagrees. In OEB staff's view, the "fair value increase" paid at the time of acquisition was strictly a transaction between Energy+ and the former Brant County Power Inc. to effect the acquisition. Customers were not involved in the transaction, and for Energy+ to recover the "fair value increase" now would essentially be asking customers to pay the premium associated with the acquisition. OEB staff notes that, if Brant County Power Inc. had not been acquired by Energy+, and instead it was Brant County Power Inc. applying to the OEB to refund to customers the gain on sale, there would be no "fair value increase" deduction to the amount being refunded to customers. The regulatory book value of the Paris facility, from the perspective of the customers, did not change when Energy+ acquired the former Brant County Power Inc. The "fair value increase" was a payment involving only the shareholders of Energy+ and the former Brant County Power Inc. OEB staff also notes that the regulatory treatment of the asset does not always have to mirror its actual treatment. OEB staff submits that this is a situation where this difference would apply. Therefore, OEB staff submits that the gain on sale calculations should not include the "fair value increase" amount and that Energy+ should provide revised calculations excluding the "fair value increase."

Energy+'s current proposal is to refund to customers the entirety of the gain on sale, which has the "fair value increase" amount netted out. OEB staff submits that no portion of the "fair value increase" should be included in the gain on sale calculations. However, OEB staff acknowledges that Energy+ has proposed no sharing of the gain on sale with its customers. Should the OEB find it appropriate to allow Energy+ to retain some portion of the "fair value increase," OEB staff submits it is more appropriate to allow Energy+ to share a portion of the <u>total</u> gain on sale (without the "fair value increase" deduction). OEB staff notes a similar situation for Innisfil Hydro Distribution Systems Limited (Innisfil Hydro), where the OEB's decision accepted the settlement proposal of the parties for a 75%-25% sharing of the gain on sale (75% to customers, 25% to the utility).[93]

The OEB noted specifically in the Innisfil Hydro decision that its acceptance of the 75%-25% allocation should not be viewed as a precedent. However, while not viewed as a precedent, OEB staff agrees with the justification for the allocation made in the

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[92] IRR E-Staff-46
[93] EB-2014-0086, Decision and Rate Order, December 4, 2014, p. 8

settlement proposal.[94] The settlement proposal stated that a 75%-25% allocation reflects the midpoint of a past Toronto Hydro-Electric System Limited proceeding, and a past Guelph Electric Systems Inc. proceeding.[95] Further, the settlement proposal noted that a 75%-25% allocation is consistent with a past Waterloo North Hydro Inc. proceeding.[96] OEB staff therefore suggests that in this scenario using a 75%-25% allocation for Energy+'s gain on sale of the Paris facility would be appropriate.

Large Use Class Fixed Charge

OEB staff notes that Toyota Motor Manufacturing Canada Inc. (TMMC), an intervenor in this proceeding, submitted interrogatories to Energy+ regarding the fixed charge of the Large Use class. TMMC's interrogatories concerned whether Energy+ had correctly calculated the fixed charge for the Large User class.[97] In response, Energy+ stated that its proposed changes to its rates, including the fixed charge for the Large User class, are in accordance with the OEB's IRM methodology.[98]

The IRM price cap adjustment is a mechanistic adjustment that is applied to distribution rates across all rate classes. OEB staff submits that Energy+ has correctly used the OEB's IRM model to calculate its 2020 rates as adjusted for a 1.2% inflation factor and Energy+'s 0.15% stretch factor. However, OEB staff notes that the OEB has updated its inflation factor for the 2020 rate year to 2%.[99] OEB staff has included an updated IRM model with this submission to reflect to 2% inflation factor and a stretch factor of 0.15%. OEB staff submits that the resulting fixed charge for the Large User class of $9,142.13 is appropriate.

Foregone Revenue

In the event that the OEB is unable to issue a final decision on Energy+'s 2020 rate application before January 1, 2020, Energy+ requested the OEB to allow it to recover incremental revenue from the effective date to the implementation date of its final rates for 2020.

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[94] *Ibid*
[95] EB-2014-0086, Settlement Proposal, November 12, 2014, p. 11; The Toronto Hydro decision is EB-2009-0139, Decision, April 9, 2010, p. 37 where Toronto Hydro was ordered to refund 100% of the gain on sale to customers and the Guelph Hydro proceeding is EB-2007-0742, Decision, July 31, 2008, p. 6 where Guelph hydro was ordered to split the gain on sale equally with customers.
[96] *Ibid*; EB-2010-0144, Proposed Settlement Agreement, March 31, 2011, p. 36
[97] IR E-TMMC-1
[98] IRR E-TMMC-1
[99] Updated on October 31, 2019

The annual revenue requirement of Energy+'s ICM request, is $368,970.[100] By dividing by twelve months, OEB staff calculates the foregone revenue of one month's recovery of this revenue requirement to be $30,748.

Energy+'s estimated 2019 revenue from distribution rates is $34,807,017 as calculated by the ACM/ICM model.[101] OEB staff estimate the price cap adjustment to increase Energy+'s annual distribution by $643,930.[102] By dividing by twelve months, OEB staff calculates the foregone revenue of one month of price cap adjustment to be $53,661.

Energy+ noted in an interrogatory response that its materiality threshold, as set in its 2019 cost of service application, is $175,000.[103] OEB staff notes that Energy+'s total foregone revenue of $84,408 (the sum of the two calculations above) would not exceed its materiality threshold unless its decision is delayed for more than 2 months past January 1, 2020.[104] OEB staff submits that the potential foregone revenues for Energy+ would likely be a small amount.

However, OEB staff notes that Energy+ has made reasonable efforts to submit its application on time and followed all deadlines set out in the procedural steps of this proceeding. Energy+ was unable to file its application by the OEB's filing deadline of August 12, 2019, and instead filed its application late by two weeks. But, as Energy+ explained, this delay was caused by unique circumstances, including a lengthy proceeding for its 2019 cost of service application, where Energy+'s regulatory staff was tied up with the Draft Rate Order of its 2019 application as late as July, 2019. OEB staff believes Energy+'s explanation is reasonable and notes that Energy+ filed a letter to inform the OEB of the delay when it determined that it could not make the August 12, 2019 deadline.[105] For these reasons, OEB staff submits that Energy+ has made reasonable efforts to ensure this application is processed in a timely manner and therefore supports Energy+'s request for an effective date of January 1, 2019 and the recovery of any resulting foregone revenue.

All of which is respectfully submitted

[100] "EnergyPlus_2020_ICM_Model_Class_C_Update.xlsx", tab 10, filed on December 2, 2019
[101] ACM/ICM Model, tab 4, cell N26
[102] Energy+'s 2020 price cap adjustment is 1.85% which is the 2% inflation factor less a stretch factor of 0.15%. $643,930 is 1.85% of $34,807,017.
[103] IRR E-Staff-63
[104] It would take 2 months before Energy+ accrues enough foregone revenue to exceed $175,000.
[105] EB-2019-0031, Energy+ Inc. 2020 IRM Application – Request for Extension, August 7, 2019