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ENERGY + INC.

EB-2018-0028

2019 DISTRIBUTION RATES

Submission
Of the
Vulnerable Energy Consumers Coalition
(VECC)

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Vulnerable Energy Consumers Coalition

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1.0 The Issues

1.1 Following the settlement conference of December 10, 2018 three categories of issues remained. These are:

- Advance Capital Module - the Southworks ACM Proposal (Issue 1.1);
- Cost Allocation and Rate Design – specifically the issues of:
  - 3.2 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?
  - 3.3 Are the applicant's proposals for rate design appropriate, including the proposal for distribution rate harmonization?
  - 3.4 Has the applicant appropriately applied the OEB's policy on residential rate design?
  - 3.5 Are the proposed Retail Transmission Service Rates and LV Rates appropriate?
  - 3.6 Is the proposal for using gross load billing for Retail Transmission Rates for customers who have load displacement generation appropriate?
  - 3.7 Is the proposal for implementing a standby charge for the Large Use, GS 1,000 to 4,999 kW and GS 50 to 999 kW customer classes with load displacement appropriate?
- The disposition of deferral and variance Accounts (Issue 4.2). There was also no agreement on the proposal to dispose of Group 2 DVAs on the bases of harmonized rate zones.

1.6 Also among the unsettled issue was the load forecast (Issue 3.1). However, the only remaining load forecast issues of concern to VECC are those impacted by the related unsettled cost allocation and rate design issues.

2.0 Southworks ACM

2.1 VECC is not disputing the ACM policy or if Energy+ meets the materiality threshold. What concerns us is the issue of timing and the fact that there are major gaps in demonstrating the cost prudence of the Southworks proposal. We examine both these issues below.

2.2 Energy+'s proposed Southwork administrative office facility is part of a larger comprehensive plan with an objective to update an existing Utility owned facility, replace rented office space and to dispose of facilities owned by the former Brant County Power and replace these with yet to be built facilities shared with Brantford Power. As shown below the current operating space comprises at total of just over 72,000 sq. feet of combined administrative and operations.[1]

[1] Exhibit 2, page 1036 of 1497

Table 2-42: Summary of Current Facilities Space

Building Location	Administration sq. ft.	Operations sq. ft.	Primary Use
Bishop Street	13,182	39,918	Leadership Team, Customer Care, Billing, Communications, Engineering, Operations (Cambridge), Supply Chain, Metering, Fleet, Information Systems Technology (IT), Human Resources (HR). Customer Care, HR, and IT to be relocated to Southworks.
Thompson Drive	5,147	na	Finance, Regulatory and Energy Efficiency (CDM). Lease to be terminated and staff relocated to Southworks in 2020.
Dundas Street	5,007	9,376	Land and building to be sold. Operations staff to be relocated to Garden Avenue.
Total	**23,336**	**49,294**	
Overall Total		**72,630**	

2.3 The facilities plan is also unusual in that Energy+ would separate its administrative functions (e.g. finance, IT, Customer services) from that of its operations (service trucks, equipment etc.) While such an arrangement is not uncommon for large utilities with multiple or large service areas it is much less common for the small and mid-size utilities in Ontario. In this case one facility, the Dundas Street/Garden Avenue replacement is a satellite operations centre to serve the Brant community.

2.4 The Energy+ proposal is also unusual because it proposes to increase the square footage allocated to administrative staff significantly. In fact most of the increase in space is for administrative offices providing a 50% increase to administrative space as compared to an 8% increase in operations space. This despite the fact that the number of employees at Energy+ has declined from 150 in 2014 to 135 forecast for the 2019 test year.[2]

2.5 The proposed facilities plan would provide for an increase of the overall square footage to just over 88,000 sq. feet as shown below.

[2] See Exhibit 4, page 58 of 540 – this table shows employees and is therefore slightly different from the FTE shown in the Appendix 2-K evidence..

Table 2-43: Summary of Proposed Facilities Space

Building Location	Administration sq. ft.	Operations sq. ft.	Primary Use
Southworks	21,892	Not Applicable	Leadership Team, Customer Service, Billing, Communications, Finance & Regulatory, HR, Energy Efficiency (CDM), IT
Bishop Street	13,182	39,918	Engineering, Operations (Cambridge), Supply Chain, Metering, Fleet
Garden Avenue	2,650 (Energy+ exclusive space)	10,601 (Energy+ exclusive space) Up to 12,243 (Shared space with BPI)	Operations (Brant County)
Total	**35,074**	**53,173**	
Overall Total		**88,247**	

2.6 What is perhaps most unusual about the Southworks facility is that it is part of a much larger property development undertaken as part of a revitalization of downtown Cambridge, Ontario. And so while the Utility is likely[3] to obtain ownership of the existing (severed) property for the remarkable price of $1.00 it will take on a number of risks and potential liabilities associated with the larger property development and the historical building it is renovating.

2.7 As compared to a more common utility facilities plan of redeveloping or purchasing a single building, often in an industrial park, in this case there is a greater financial risk due to the complicated nature of the transaction. The portion of the building purchased by Energy+ is an older historical building which requires renovation. With that are inherent financial risks due to the unknown nature of the work to be done, including environmental remediation. Costs are also less certain because of the interrelationship between the portion of the building to be renovated by Energy+ and the other parts of the building and the larger site being developed. These uncertainties have already been demonstrated by the doubling of the cost estimate from $4 million in the original filing to the revised $8.1 million subsequent to the settlement conference of November 7, 2018. The Utility explains the change as an error in the understanding of the class specificity of the contractor's estimate. But as an explanation for the doubling of the estimated cost this stretches credulity. Energy+ originally believed a $4 million costs estimate was sufficiently accurate to file in support of an ACM. We suggest that it is the inherent uncertainty of this unique renovation that has led to the mismatch between the Utility's original expectations of the project costs to the more recent estimate provide by the contractor/consultant.

[3] As per Vol. 1 March 7, 2019, page 32 the transaction at $1.00 has yet to be consummated

2.8 In addition to the greater cost uncertainty inherent in the Southworks proposal there are risks with respect to the timing of occupation. Had the Utility decided to simply lease existing office space it would be able to make more certain plans. As it stands occupation of the Southwork project is dependent on not only completion of the building in question, but on the building of the development's adjoining condominium project.

2.9 The expected timing for occupation of the various facilities is provided below.[4]

Facility	Construction Period	Occupancy / Move out Date	Number and % Employees	Cost Estimate
Southworks	March 2020 – March 2021	Occupancy July 2021	67 (51%)	$8.1 million
Bishop St.	2024	Engineering & Operations remain occupied	51 (39%)	$2.0 million
Thompson Dr.	N/A	Vacate July 2021	16 (12%)	N/A
Dundas St.	N/A	Vacate TBD	13 (10%)	N/A
Shared Facility with BPI	TBD	Occupancy 2020	13 (10%)	$4.4 million

[4] Technical Conference Questions, January 22, 2019, VECC - 62

2.10 Too this Energy + adds[5]:

> The dates provided for Southworks construction and occupancy could be pushed out 6 –9 months based on the detailed construction timeline of the condominium towers that are being constructed as part of the overall development. Energy+ will be utilizing parking space in an adjacent tower for its employees and visitors. Occupancy will only be feasible once the parking garages are completed and construction activity on the site diminishes to a level that enables a safe and comfortable work environment.

At the technical conference Mr. Miles of Energy+ further clarified:[6]

> MR. MILES: Well, there has been some discussion with the developer about occupying Southworks when the parking podium component of the condo tower is finished. So construction could still be happening on the upper floors, but the parking would be safe and clear of construction and available for parking.
>
> So if that were to occur, then we could be in there as soon as July 2021, which, you know, is what we have stated in the table.

2.11 Meaning that in the event it could, by Energy+'s own admission, be mid-2022 before occupancy of the Southworks facilities if, for example, the rather unusual plan of parking in the unfinished adjoining condominium building(s) turns out not to be feasible.

2.12 In our submission there is a high risk that the proposed Southwork buildings will not be available until some time in 2022 and perhaps beyond.

2.13 In demonstrating the prudence of the Southwork project Energy+ also attempted to demonstrate the reasonability of the costs by providing the following comparables[7]:

[5] Ibid

[6] Technical Conference, January 23, 2019, pg. 10

[7] Technical Conference Questions, January 22, 2019, SEC-5. In the original response Table 6 includes a number of footnotes clarify the costs, but these clarifications are not material to the presentation.

Table 6: Cost and Utilization Comparison to Other Distributors - Updated to Split Energy+ Facilities

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 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/ Refurbish	Purchase/ Refurbish	Purchase	Refurbish	Custom Build	Custom Build	Purchase/ 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
Capital Cost @ Highest End of Estimate Range	$18,040,000	$9,720,000	$5,720,000	$2,600,000				
Capital Cost/FTE @ High Range	$137,710	$145,075	$440,000	$50,980				
Capital Cost/Square Foot @ High Range	$204.44	$444.00	$431.67	$48.96				

2.14 In its original evidence Energy+'s provided only the aggregate project comparison. In response to questions it provided this detailed breakdown comparison which shows the capital costs of the Southworks facility to be considerably higher than all of the comparables presented. However, we would argue the comparisons are flawed in any event. The two highest figures shown, Waterloo North and PUC Distribution, are considerably in the past and no context has been provided. For example, we note that the referenced PUC facility was built prior to that Utility filing its cost of service application. Moreover the PUC building is shared with its affiliate who provided in 2013 rent (offsetting PUC's regulated costs) of $1,317,274 for use of the building.[8] Likewise no context is provided with respect to the facilities of Waterloo North and so little can be drawn about how reasonable is that comparison. Leaving aside those two utilities we note that $11-12 million appears to be a reasonable proxy for a renovation/build of mid-size utility facilities. In any event we submit the Board should put little weight in these comparisons as a test of the prudence of Energy+'s proposal.

[8] See PUC Inc. EB-2012-0162, Exhibit 2, Tab 2, Schedule 7, pg. 16 & EB-2012-0162 IR 2-Staff-14

2.15 Moreover a close examination the Energy+ alternative cost of the facilities does not hold water. We invite the Board to consider that Energy + has added the "additional soft cost" of building permits, development charges etc., that are in excess of the entire projected Southwork costs. No explanation is provided for why the "soft costs" associated with a new building or more comprehensive renovation of the Bishop Street facility should be more than the entire costs of the Southwork project which presumably also includes similar "soft" cost[9].

2.16

Options Considered	Construction costs estimated by Melloul-Blamey	Additional "soft costs" identified by Energy+ (e.g. building permits, development charges, professional consultants etc.)	Overall project cost
Expand the existing building	$19,150,000	$9,488,555	$28,638,555
Expand the existing building to LEED standards	$23,000,000	$10,078,530	$33,078,530

Options Considered	Construction costs estimated by Melloul-Blamey	Additional "soft costs" identified by Energy+ (e.g. building permits, development charges, professional consultants etc.)	Overall project cost
Construct a new building	$22,800,000	$8,734,277	$31,534,277
Construct a new building to LEED standards	$24,000,000	$8,980,677	$32,980,677

2.17 These estimated soft costs of between $8.7 and $10 million are in stark contrast to the equivalent cost provided for the Southwork project of $1.3 million.[10]

[9] These tables were subsequently updated in the evidence updated at December 13, 2018 to reflect the change in the estimate costs for the Southwork project

[10] Technical Conference Questions SEC-1

Updated Class C Estimate, as per Design Brief	**$**	**6,753,020**
Additional Costs not included in Estimate		
Professional Fees: Architectural, structural, mechanical, electrical, civil	$	607,772
Firewall	$	254,000
Furniture / stations	$	400,000
Building Permit Fees	$	10,000
Increase contingency	$	75,000
	$	1,346,772
Total		
	$	**8,099,792**

2.18 In our submission it is simply not credible to claim that the "soft costs" of a single building, likely built or acquired in an industrial park, would exceed that in the Applicant's current proposal for renovating an historic building in a residential inner city project <u>and</u> renovating an existing building in an industrial park. Clearly either the costs in the former option are overestimated or in the latter, underestimated.

2.19 The other factor that is not considered in comparing costs is the increase in operating costs for parking. Energy + estimates it will incur $150,000 in annual parking costs. This cost is not included in the capital costs, but in OM&A costs.[11] A more accurate comparison of the total costs for the competing options would include the discounted value of these annual occurring incremental costs. That has not been done.

2.20 In our submission it is not evident that the Energy+ proposal is the least cost solution to its facilities need.

2.21 Energy + gives one of the benefits of the Southwork project as the consolidation of the administrative staff to a single location. While this is true, the proposal continues to separate operational staff from administrative staff. Energy + admitted that interaction will continue to be required in the future and so the current plan resolves only part of the current dilemma.

2.22 If one does accepts the premise of separating the administrative from operations functions is desirable then the appropriate comparable to the Southwork proposal would be the cost to lease or own similar office space. Certainly leasing would provide more flexibility for the future than the proposal which has in overbuild the space in anticipation of future staff. In this regard VECC had this exchange with Energy+ at the hearing:

[11] Vol 1, March 7, 2019, pg. 87

MR. GARNER: Sorry, but you seem to be mixing two different -- apples and oranges in that scenario, because the cost for a -- you are talking about the cost for what I will call the standard utility building in an industrial park that combines all the operations, with the idea of a business office separate from that type of building, and that's the option you chose.

So I am asking kind of a little different question. Having chosen that option saying, okay, we are going to separate the buildings because we want to keep Bishop Street, let's say, and we want to renovate it and that makes sense to us. Then the next thing, it seems to me, you would have done is done an analysis of doing any building you bought on a square footage rental basis in the city, let's say, down--anywhere near where you want to be, or any other place in Cambridge, by the way, and said to yourself on an annual square footage basis, it's cheaper to build this--buy this, build this than it is to go and rent 70--you know like this building right here where, you know, the Board occupies and has 70 people inside this building and working right now, right.

So they've gone through an exercise in which they went around and found how much per square foot, and found the best option. And unfortunately, this is it and took this building, right. I am wondering why--did you do that same exercise and say, okay, having chosen this, let's go see what the square footage of building is and do that. Did you do that exercise?

MR. MILES: We did not do it after we choose this as a viable option, and a couple reasons. One, the location--first of all, there's not a lot of real estate on the market in Cambridge. It's not like Toronto where you can find a 21,000 square foot piece of sort of move-in ready real estate.

But we also—we like the location of this facility and it's our intention as we build it out, as we do the renovations, we are going to tender out everything construction and material related. The only thing that we are not going to tender out is the construction management aspect of it, which is about $400,000 of the total cost.

So our view was we will end up with a prudent market price for the project.

MR. GARNER: Well, that's one of the things I want to just ask you about. In the $370 per square foot of capital cost for this, the difficulty of course I have with looking at that--I don't have a difficulty. But the difficulty with that figure is if I wanted to compare now just the standard, as you say, lease and rent office space in Cambridge, how much per square foot, I would really have to convert all your costs, including your parking and other things that might happen, into a square foot cost of office space in Cambridge vis-à-vis a square foot of Southworks office space, so to speak.

And I heard you just say you haven't done that, right, because you have now chosen the option you have and so it becomes irrelevant to you what the square footage cost of building Southworks is, because you have made that choice. Is that right?

MR. MILES: I wouldn't say it's not relevant. I go back to my earlier point where we plan on tendering out the construction and the materials for the project that we are undertaking. So it's our view that at the end of the day, the costs should be equivalent on a per square footage basis.

MR. GARNER: Okay. I guess what I would ask you is -- I guess you could demonstrate that when you're finished. So if you were finished this whole project in five years, two years, whatever it is that finishes it, there would been ability for you to say, okay, now I know what my square footage cost is, and I can now compare that to Cambridge equivalent places for 350 feet. And then I can make an assessment as to how well I did vis-a-vis the current market rate.

MR. MILES: It could be done, yes.

2.23 In a nutshell this exchange highlights two things. The first is that Energy+ has a clear preference for the Southworks project based on the concept of ownership and second, that no effort was made to understand the comparative value of leasing office space rather than building or renovating. This, we submit shows a fatal flaw in the attempt to convince of one of the prudence of the proposal.

2.24 First there is no clear evidence why Energy+ requires 21,000 sq. ft. of new office space – given that under its proposal it will retain the existing administration office space at its Bishop Street facility. Even if one were to accept that it does require this amount of office space there is no evidence, as admitted by Mr. Miles of any due diligence done to compare existing leasing opportunities. For that matter there is no exploration of building just office space in a place other than this unique revitalization development. This, we submit should have been a priority for Energy+ given that one might presume that an inner city revitalization co-development project might be at a premium as compared to a more traditional perhaps suburban office site. In this case there is no way for the Board to test the premise that the cost of the office space being built for Energy+ in Southworks is similar to other available or alternatively built space in the greater Cambridge region.

2.25 Under the Advanced Capital Module (ACM) formula a materiality threshold is calculated which in essence considers the normal amount of investment made during a rate period and for which no adjustment to rates. In this case the materiality threshold would provide a maximum eligible incremental capital amount of $8,375,313[12]. Significantly close to the current $8.1 million cost estimate for the Southwork project.

[12] Exhibit 2, section 2.9.2.1, pdf pg, 160

2.26 The ADM policy followed the earlier establishment of the Incremental Capital Module formula. In essence the difference between the two lies in what be described as the "forcastability" of a large specific capital program. The similarity and difference is outlined in the Board's ACM Report.[13]

> The ICM was in essence a funding mechanism for significant capital projects for which a utility required rate recovery in advance of its next regularly scheduled cost of service application.
>
> ………………….
>
> This approach adapts and adds to the ICM mechanism. Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP
>
> The ACM approach should also facilitate regulatory efficiency by placing the requirement to establish the need and prudence for any additional incremental capital spending within a cost of service proceeding. This is well suited to such forms of review and when the five-year DSP is tested.

2.27 That is, the ACM, like the ICM mechanism is a means by which a utility might fund and therefore "smooth" the impact of major specific projects. The ACM also provides a means of considering prudence in advance of the project. In the case of the former objective, funding, it is clear that Energy+ does not require the ACM (or ICM for that matter) to finance the project as was made clear in this exchange with VECC:[14]

> MR. GARNER: Okay, thank you, Mr. Miles. Would I be correct to say the reason you want to do the ACM versus an 21 ICM later, when you might have more certainty, is that it's not the financial burden you have over '19 and maybe even '20; it's the uncertainty you would enter into in entering into any construction without the certainty you will be able to move forward. Is that really the issue?
>
> MR. MILES: That's correct and that is the issue, yes.

2.28 The inherent difficulty in the other aspect of the ACM policy – determining prudence- is that it attempts to do so in years in advance of the project being completed or in this case even begun. The Board routinely reviews capital projects that will be completed in the test year of a cost of service application. However for projects that are constructed over multiple years or, as in this case, a project that will take place some time in the future the determination of prudence in advance becomes problematic. In these cases a post-facto prudence review is inevitable and any variance from the amounts projected in the ACM (or ICM) are subject to a higher level

[13] Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, pg. 5 & 11
[14] Technical Conference, January 23, 2019, pg.11

of scrutiny. For this reason the Board generally establishes variance accounts, capturing both underspending (for required adjustments to the ACM/ICM rate rider) and overspending (for consideration of the prudence of the overspending). Only in extraordinary cases should amounts in excess of the budgeted projection be allowed into rate base – otherwise the entire exercise risks turning farcical.

2.29 As we have detailed above our submission is that Energy+ fails to meet the test of prudence for the proposal as a whole. It has not adequately demonstrated that it could neither renovate its current building to meet its office needs, nor build a new building at a lower overall costs, nor renovate the Bishop building but lease office space for significantly less than the current proposal.

2.30 In our submission the Board could consider one of two options to address the shortfall in this Application. The most straightforward is to simply deny the ACM proposal and until such time as the major uncertainties are better understood. In our view there are a number of timing and financial risks with the innovative approach Energy+ has chosen including the fact that the project is being done in conjunction with other related developments. Among the most significant of these are the renovation of part of a heritage building, the associated condominium project and the availability of parking all of which might easily result in an occupation as late as or later than 2022. And perhaps at significantly higher costs than currently estimated.

2.31 Given that financing is not an issue for Energy+ to proceed the Board could invite the Utility to file an updated ICM proposal at a time closer to a known occupancy date. The Board might also direct Energy+ to provide more considered comparable data including the cost of alternative leased office space in the Cambridge region. In our view such leased space would be for the immediate requirements of Energy+ and not the larger space of Southworks which is argued for on the basis of contemplated, but as of yet undetermined needs.

2.32 Alternatively, the Board might cap the amount it is willing to allow into rates at the $8.4 million proposal. While this would ignore the fact that there is no direct knowledge of comparable leased office space it would protect customers from future overruns and provide an incentive for the Utility to contain costs. If the Board chooses this option it should, in our submission, forewarn the Utility that the annual $150,000 in parking costs may not be allowed into the OM&A costs of future rates (nor be allowed to be capitalized as part of the project costs). That decision is by necessity made by a future panel of the Board. In any event, in VECC's view it is not entirely obvious that ratepayers should be paying for the inner city parking costs of Energy+ employees. Certainly no evidence has been led which would indicate that similar employees in the downtown Cambridge area (e.g. government employees) enjoy such benefits.

3.0 Cost Allocation and Rate Design (Bill's sections to insert)

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

3.1 This part of VECC's argument deals with a number of issues related to cost allocation that have arisen during the proceeding. It is organized into the following sections:

- Overview
- Principles of Cost Allocation
- Approaches to Cost Allocation
- Direct Allocation
- One or Two Large Use Classes
- Cost Allocation Treatment of Bulk (>50kV) Facilities
- Cost Allocation Treatment of Overhead and Underground Distribution Facilities
- Cost Allocation Treatment of Embedded Distributors

Overview

3.2 The determination of an electricity distributor's rates can be viewed as a two stage process. The first stage focuses on the determination of the overall revenue requirement that the distributor will be allowed in the test (or rate) year and the resulting average rate increase that will be experienced by its customers. The second stage is the "rate making" stage where individual rate schedules for each of the distributor's customer classes are determined such that they will collectively cover the approved revenue requirement. The rate making stage itself consists of two steps. The first is establishing the portion of the total revenue requirement to be recovered from each customer class while the second involves establishing the rate schedule for each customer class that will return the class' share of the revenue requirement.

3.3 The purpose of a cost allocation study is linked to the first step of the rate making stage and involves establishing a methodology for assigning/allocating the pre-established total revenue requirement amongst the distributor's customer classes. The ratio of the revenues that would be collected from each customer class (assuming the same average rate increase is applied to each) to the costs allocated to each customer class is called the revenue to cost ratio (R/C ratio). This ratio provides an important reference in determining rates for each customer class that are just and reasonable[15]. While the R/C ratio would ideally be 100%, regulators (including the OEB[16]) typically set an R/C ratio range within which it is considered that a customer class is

[15] EB-2007-0667, Application of Cost Allocation to Electricity Distributors, Report of the Board, page 2 and Transcript Volume 1, page 176
[16] EB-2007-0667, Application of Cost Allocation to Electricity Distributors, Report of the Board, pages 3-11

paying its fair share of costs. The establishment of R/C ratio ranges recognizes that cost allocation calls for the exercise of some judgment in terms of the cost allocation methodology employed as well as the need for simplifying assumptions and the use of sample data[17].

Principles of Cost Allocation

3.4 There is general agreement that cost allocation should reflect cost causality. Mr. Pollock, who has been involved with cost allocation in a number of jurisdictions, testified that it's *"the most common denominator of every cost allocation study that I have before involved in*"[18]. Similarly, there is general agreement in this proceeding that a fundamental principle of cost allocation is that it should reflect cost causality. This is evidenced by the testimony of the witnesses for both Energy+[19] and TMMC[20].

3.5 However, while there is general agreement that cost allocation should be based on cost causality, differences of opinion frequently exist as to exactly how to establish cost causality, and exactly how it should be applied, as Mr. Pollock noted[21]:

> MR. HARPER: However, the fact you have been involved in so many proceedings and we are here today suggests that -- would you agree that frequently there are disagreements as to exactly how to establish cost causality, and exactly how it should be applied, and that's sort of where the rubber hits the road and disagreements typically arise?
>
> MR. POLLOCK: Yes, I would agree. I mean reasonable minds can have different opinions.

3.6 Indeed, as noted earlier, this is one of the reasons why regulators (including the OEB) have "ranges of reasonableness" when applying the results of cost allocation studies.

3.7 VECC agrees that a fundamental principle of cost allocation is that it should reflect cost causality and submits that the issues arising in this proceeding are related to how this principle should be applied in the case of Energy+ and, more specifically, in the case of its largest customer TMMC.

3.8 The Board will ultimately make a decision as to the appropriate cost allocation methodology given Energy+'s circumstances. However, in making such a decision, VECC submits it is important for the Board to be consistent and to apply the same approach/methodology in all circumstances and to all of Energy+'s customer classes. In VECC's view it is inappropriate and unfair to have fundamentally different approaches to cost allocation applied to different customer classes.

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[17] EB-2007-0667, Application of Cost Allocation to Electricity Distributors, Report of the Board, pages 2-4
[18] Transcript Volume 2, page 77
[19] Transcript Volume 1, page 176
[20] Transcript Volume 2, pages 76-77
[21] Transcript Volume 2, page 77 and pages 78-79

Approaches to Cost Allocation

3.9 In Ontario, the Board annually releases a cost allocation model that electricity distributors can use in their cost of service based rate applications. This model is based on an OEB-approved methodology[22] that reflects various cost allocation reports issued by the Board including: i) Board Directions on Cost Allocation Methodology For Electricity Distributors (RP-2005-0317), ii) Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219), iii) Review of the Board's Cost Allocation Policy for Unmetered Loads (EB-2012-0383) and iv) the OEB's letter of June 12, 2015 regarding cost allocation for Street Lighting. The first report lays out the overall approach to cost allocation while the subsequent reports and letters represent refinements introduced over time. The methodology, as set out in the Board Directions on Cost Allocation Methodology For Electricity Distributors, is one that includes[23]:

- A limited use of direct allocation to those circumstances where 100% of the use of a clearly identifiable and significant distribution facility can be tracked directly to a single rate classification. Similarly, there is a requirement that direct allocation must also be used where identifiable O&M activities can be directly allocated to one customer classification.
- The requirement that where the prescribed test for direct allocation cannot be met, a distributor will be required to consider whether distribution assets should be broken out into bulk, primary and secondary to more accurately allocate costs of facilities to rate classifications based on how they use various parts of the distribution system.

3.10 VECC notes that an important aspect of the OEB-approved methodology is that while it is based on the costs set out in the Uniform System of Accounts ("USOA"), the accounts themselves are grouped into the following services/functions[24]:

- >50kV assets deemed to be distribution.
- Bulk (if any)[25]
- Primary
- Secondary

3.11 For all of the USOA accounts (and sub-accounts) assigned to each of these functions a common allocator is used based on the total load and customer count for each customer class deemed to be using that service/function[26]. This approach is referred to as pooling[27] and

[22] Filing Requirements For Electricity Distribution Rate Applications- 2018 Edition for 2019 Rate Applications, Chapter 2, page 44
[23] Board Directions on Cost Allocation Methodology For Electricity Distributors (RP-2005-0317), pages 31-32
[24] Board Directions on Cost Allocation Methodology For Electricity Distributors (RP-2005-0317), page 34 and Appendix 6.1
[25] Note: Energy+ does not have any "bulk" facilities as defined by the Board's cost allocation methodology. However, Energy + does have >50 kV assets which are deemed to be distribution and which, in this proceeding, have been referred to as bulk assets.
[26] Board Directions on Cost Allocation Methodology For Electricity Distributors (RP-2005-0317), Appendix 6.1

reflects an approach to cost causality that is based on the services (e.g., primary service, secondary service, etc.) that a customer/customer class uses as opposed to the specific assets used. As the subsequent discussion of the individual issues indicates a key question is whether "pooling" is the appropriate approach to use in the case of Energy+'s cost allocation methodology.

3.12 As well as distribution rates, Energy+'s Application is seeking approval for: i) its proposed Retail Transmission Service Rates (RTSRs) to recover charges from the IESO and its host distributors for transmission services and ii) its Low Voltage (LV) rates to recover charges from its host distributors for the delivery of power at distribution voltages. The costs incurred by Energy+ for these services are not part of its distribution revenue requirement because they flow either from the IESO/host distributors for transmission-related services or from other distributors as LV service. Therefore, they are not included in the Board's cost allocation model. However, they too must be allocated to customer classes in order for the appropriate rates to be established.

3.13 However, the Energy+ >50 kV facilities, which are rightly included in its distribution revenue requirement and cost allocation, provide some of Energy+'s customers a similar service to that provided to other Energy+ customers by the >50 kV facilities on Hydro One's transmission network for which the utility pays Transformation Connection Service charges to the IESO[28].

3.14 In such cases, it is important, in terms of fairness, that the same approach to establishing cost causality must be used for both the "IESO" [29] and the "Utility" service. To do otherwise, would also result in customers who receive a transmission-related service from the IESO not being treated the same as customers who receive a similar, but utility provided, service.

Direct Allocation

3.15 In its initial Application Energy+'s cost allocation model did not directly allocate any of its distribution costs to customer classes. However, in its Argument in Chief ("AIC") Energy+ states[30]:

> 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. This is shown in Table TMMC-IR-2(d) as the net of the Feeders line and the Contribution line.

3.16 At the same time, Energy+ goes on to note that that its "*estimate of O&M costs associated with those feeders has a fairly high margin for error, since there was not a time study completed*

[27] Transcript Volume 1, page 115
[28] Transcript Volume 1, page 118
[29] That is the RTSR related costs
[30] Page 20

to create these estimates". Also Energy+ states that it "*is of the view that no other costs should be directly allocated to the Large User customer class*"[31].

3.17 On the other hand, in his updated evidence, TMMC's expert witness (Mr. Pollock) directly allocates to the TMMC Large Use class the cost of the two dedicated feeders supplying TMMC, the capital contribution TMMC made for those feeders, the costs of TMMC's meters and the O&M costs related to these assets[32].

3.18 It should be noted that in both Energy+'s updated proposal and Mr. Pollock's proposal, the poles associated with the dedicated feeders are not directly assigned but rather allocated in accordance with the methodology incorporated in the Board's cost allocation model[33]. It should also be noted that, in both cases, the proposal to directly allocate certain assets was considered to be consistent with the Board directions on cost allocation methodology[34].

3.19 The proposed treatment of TMMC's two dedicated feeders and the TMMC meters are addressed below.

Dedicated Feeders

3.20 In VECC's view the two dedicated feeders are a significant asset in terms of the supply to TMMC and are currently configured such that they can only be used by TMMC[35]. To this extent they meet the requirements for direct allocation as set out in the Board Directions on Cost Allocation Methodology For Electricity Distributors (RP-2005-0317)[36]. However, TMMC's circumstances are unique in that while the feeders supplying it are dedicated the poles supporting the feeders are not[37]. This means that while some of the primary distribution service costs can be directly allocated[38] there are others that cannot[39]. In this regard, Energy+'s/ TMMC's circumstances differ from those of either Enwin or Horizon which were cited by TMMC's counsel during cross-examination of the Energy+ witnesses[40] as examples and precedents for direct allocation. In Enwin's case all of the costs of the transformation stations were directly allocated[41] and in the case of Horizon all of the feeder costs (both underground conductor and conduit) were directly allocated[42].

[31] AIC, Page 20
[32] Transcript Volume 2, page 57
[33] AIC, page 20 (Energy+) and Transcript Volume 2, page 49 (Mr. Pollock)
[34] AIC, page 20 (Energy +) and TMMC Updated (February 2019) Evidence, page 52
[35] Transcript Volume 1, Page 144
[36] Page 31
[37] Energy+ response to IR-TMMC-15-4
[38] i.e., The conductor costs recorded in USOA 1835-4
[39] i.e., The pole costs recorded in USOA 1830-4
[40] Transcript Volume 2, pages 2-5
[41] Transcript Volume 2, page 2
[42] Transcript Volume 2, pages 7-8 and page 12. It is noted that any shared assets were fully depreciated and not material to the cost allocation process

3.21 The Board's direction on the use of direct allocation does not make specific reference to USOA accounts or services/functions but rather uses the term "distribution facility"[43] and therefore VECC submits that interpretation and judgment is involved in determining whether the requirements for direct allocation are met. It is VECC's view that other considerations in this determination include:

- The fact that the Board's rationale for establishing the exclusive use criteria was that "the 100% use test can also be applied more clearly and consistently"[44].
- The costs from USOA 1835 (Overhead Conductor) directly allocated to TMMC do not include the cost of the fibre optic cable that is owned by Energy+[45] between Preston TS and TMMC.
- Energy+ has indicated that its estimate of O&M costs associated with the feeders has a fairly high margin for error[46].

3.22 Overall, VECC is not opposed to the use of direct allocation in the case of the feeders. However, should the Board decide to adopt direct allocation for these feeders it should indicate that it is based on the specific circumstances involved and should not be considered as generic precedent of other cases/distributor – each of which would need to be judged on its own merits. Furthermore, in light of the uncertainties regarding the costs associated with the directly allocated assets the Board should revise the R/C ratio range for the Large Use class that has directly allocated costs from 85%-115% to 80%-120% (similar to that used for the General Service classes) in recognition of the increased cost uncertainty.

TMMC's Meters

3.23 VECC agrees with Energy+'s position that meter costs should not be directly allocated to TMMC. First, they are not a "significant" distribution facility. Second, there is nothing unique about TMMC having dedicated meters. All customers have dedicated meters. Finally, as with all customers, TMMC's meter costs are not recorded in a separate account or sub-account. In order to identify the costs, Energy+ had to make reference to the related work order to determine the costs[47]. In theory there is no reason why a similar exercise could not be undertaken for other customers/customer classes. However, VECC is not proposing that this be done.

3.24 In its Report - Board Directions on Cost Allocation Methodology For Electricity Distributors (RP-2005-0317) - the Board noted[48] that while cost causality was the primary criterion in developing a cost allocation methodology, secondary considerations included the availability and reliability of the data to support the exercise, as well as concerns of materiality,

[43] Board Directions on Cost Allocation Methodology For Electricity Distributors (RP-2005-0317), page 31
[44] Board Directions on Cost Allocation Methodology For Electricity Distributors (RP-2005-0317), page 31
[45] Technical Conference Transcript, Volume 1, pages 31-32
[46] AIC, page 20
[47] Transcript Volume 1, page 122
[48] Page 3

practicability and consistency. In VECC's view the current cost allocation methodology, which addresses the fact that different customers use different types of meters with different costs through the use of weighting factors[49] , represents an appropriate balance between cost causality and the need for a consistent approach for all customers that is practical and workable.

<u>One or Two Large Use Customer Classes</u>

3.25 Mr. Pollock (TMMC's expert witness) proposes that there be two Large Use classes: one consisting of TMMC and a second consisting of Energy+'s other Large Use customer[50]. On the other hand, Energy+ does not consider two separate Large Use customer classes as appropriate due to a number of factors, including the increased regulatory and administrative costs entailed by this, ongoing problems with confidentiality of customer information (as there would only be one customer in each of the two rate class), and challenges with any future Large Use customer[51].

3.26 Mr. Pollock considers two Large Use customer classes to be appropriate on the basis that[52]:

- TMMC operates a load displacement generation (LDG) facility while the other Large Use customer does not have any LDG facilities
- TMMC's load is in excess of 20 MW, while the other Large Use customer's load is only about 5 MW.
- TMMC receives service from dedicated feeder lines that are directly connected to a transformer substation. This is in contrast to the other Large Use customer, which receives Primary Distribution service using Energy+'s integrated primary distribution network.
- With the sole exception of primary poles, all of the distribution facilities that serve TMMC are exclusively used by TMMC, and no other Energy+ customers can be served from these facilities. This means that all distribution facilities used to serve TMMC, other than poles, can be directly assigned to TMMC.

3.27 VECC submits that, of the factors cited by Mr. Pollock, the only one that is relevant to the consideration of whether there should be one or two Large Use customer classes is the existence and cost allocation treatment of the dedicated feeders.

3.28 Mr. Pollock has stated[53] that the results of his cost of service study are not meant to capture the cost of providing both Supplementary and Standby Service. As result, the fact that TMMC operates a LDG facility should have no impact on the decision as to whether one or two Large Use classes are required.

[49] Transcript Volume 1, page 122
[50] TMMC Updated (February 2019) Evidence, page 8
[51] AIC, page 20
[52] TMMC Updated (February 2019) Evidence, pages 9-10
[53] TMMC response to VECC IR 5.2

3.29 VECC does not consider customer size, by itself, to be a determining factor for establishing separate customer classes unless it leads to the customers requiring different types of facilities or services. The fact that TMMC is larger than the other Large Use customer and that some costs are fixed on a per customer basis is already recognized in the Board's cost allocation methodology through the use of both customer count and volume as allocators where appropriate.

3.30 In this case, both Large Use customers receive service at 27.6 kV[54]. What is different is the nature of the facilities used by each. If the Board determines that direct allocation of the costs related to the dedicated feeders used to serve TMMC is appropriate then VECC submits there is a case for two customer classes. Otherwise, there is not.

3.31 However, VECC notes that, when performing a cost allocation study based on two Large Use classes, neither Energy+ nor Mr. Pollock made any allowance for the diversity between the two customers that is inherent in the 4NCP demand allocation factor[55] used for the single Large Use class and that would be lost in moving to two Large Use classes. The existence of such diversity in loads was confirmed by Energy+ in response to Technical Conference Questions[56] along with an estimate as to the impact of the losing this diversity with the establishment of two Large Use customer classes. The existence of diversity of load was also noted in Mr. Pollock's evidence[57]. VECC submits that, if the Board decides to create two Large Use classes, then it should also direct Energy+ to adjust the 4NCP demand allocation factors used in the cost allocation methodology to account for this loss in diversity.

Treatment of Bulk (>50 kV facility) Costs

3.32 Energy+ allocates its bulk facility costs to all customer classes with the exception of the Embedded Distributors[58]. In contrast, Mr. Pollock also excludes his proposed two Large Use customer classes from the allocation of bulk facility costs[59].

3.33 In VECC's view the difference between the two proposals lies in the approach used for establishing cost causality. Mr. Pollock's approach is based on the view that since neither TMMC nor the other Large Use customer "use" Energy+'s bulk assets they should not be allocated any of the associated costs. This is consistent with Mr. Pollock's approach to cost

[54] Energy+ response to TMMC IR #15
[55] The 4NCP demand allocation factor is based on the four highest monthly peaks for the combined load of all customers in the class. Since customers in a class do not all necessarily "peak" at the same time, separating these customers into two or more customer classes will result in 4NCP factors that will likely sum to more than the 4NCP factor for customer class in aggregate.
[56] VECC-TCQ-74
[57] TMMC Updated (February 2019) Evidence, pages 47-49
[58] Energy+ response to VECC_TCQ-76 and AIC, pages 20-21
[59] Transcript Volume 2, page 62

causation which is that if a customer/customer class is not connected to and does not use an asset then there should be no allocation of costs to the customer/customer class[60].

MR. HARPER: That's fair. And I think -- from your perspective, I think you have covered off some of this in your direct examination is that when you were talking about not allocating underground and not allocating bulk to TMMC, I think that reflected -- I would characterize a general principle and I think it was in your evidence that if a facility is not used or electrically connected to a customer, then the cost of that facility should not be allocated to that customer. Is that a fair representation?

MR. POLLOCK: If they didn't cause it, if there's no connection between that customer's load and the existence of an investment, whatever that investment is, then you wouldn't allocate that investment to that customer or that class.

3.34 For ease of reference, VECC will refer to this as the "asset specific" approach to cost causality and cost allocation.

3.35 In contrast, Energy+ takes what VECC has referred to earlier as a "services" or "pooling" approach to cost causality and cost allocation. Under this approach, since Energy+'s bulk facilities and Hydro One's transformation stations essentially provide the same service which is used by all customers, the cost of both are "allocated" to all customer classes based on their total load – regardless of whose facilities are actually used to provide the transformation service. In the case of Energy+'s bulk costs this is done by including the total load for each customer class[61] in the 4NCP demand allocation factor used to allocate the costs. In the case of the Hydro One transformation connection costs billed by the IESO the same result is achieved by including the total load for each customer class in the allocation and determination of the RTSR charges.

3.36 In theory either approach could be used. However, whichever approach is chosen it must be applied consistently to all customer classes and to both Energy+'s bulk facilities' costs and the transmission connection charges levied by the IESO. Otherwise, as noted in Energy+'s Argument in Chief, issues of cross-subsidization arise[62]. Therefore, applying the approach proposed by Mr. Pollock would require adjusting the demand allocation factors for the other customer classes that are used to allocate Energy+'s costs of bulk facilities. In his evidence Mr. Pollock has made no such adjustment[63]. It would also require altering the determination of

[60] Transcript Volume 2, page 79
[61] As noted earlier the one exception is the customer classes representing embedded distributors. However, in a Decision dated March 4, 2019 the Board found that alternative embedded distributor cost allocation methodology is out of scope in this proceeding.
[62] AIC, page 21
[63] There is no discussion of such an adjustment in his evidence and no such adjustment was made to the 4NCP allocation factors used in his cost allocation models (Schedule JP-11).

the RTSR charges to exclude the loads in each customer class that are served from Energy+'s bulk facilities – an issue which Mr. Pollock has also not addressed[64].

3.37 Furthermore, Energy+ has noted[65] that its distribution system is dynamic and constantly changing based on the most current operating requirements. One of the implications of this is that planned and unplanned switching events can require load to be transferred between transformer stations, including those owned by Energy+ and Hydro One[66]. As a result, establishing "usage" depends on when the snap-shot in time is taken. Indeed, while Mr. Pollock has allocated no bulk facilities cost to the other Large Use class based on the fact it is served by the Hydro One-owned Galt TS[67], Energy+ has testified that the customer could on rare occasions be served by Energy+'s MTS#1[68].

3.38 For these reasons, VECC submits that allocating the costs of bulk facilities (and establishing RTSRs) using a "pooling approach" that includes all customer's/customer classes' loads as proposed by Energy+[69] is a more practical and fair approach.

<u>Treatment of Overhead and Underground Distribution Facilities</u>

3.39 In his evidence proposing two Large Use customer classes, Mr. Pollock includes the TMMC customer class and the other Large Use customer class in the allocation of poles. However, Mr. Pollock excludes the TMMC Large Use class from the allocation of overhead conductor costs as well as the allocation of the costs associated with underground facilities (i.e., conductor and conduit)[70]. In the case of overhead conductor costs, TMMC is excluded on the basis that the cost of feeders to serve TMMC has been directly allocated. In the case of the underground facilities, TMMC is excluded from the allocation on the basis that it is not electrically connected to and cannot use the underground facilities[71]. Again, this reflects Mr. Pollock's "asset specific" approach to cost causality and cost allocation.

3.40 Energy+ disagrees[72] with Mr. Pollock's proposal to not allocate any underground facility costs to TMMC. Energy+ notes that:

> Currently the costs of both overhead and underground facilities are allocated to all customer classes in accordance with the Board's cost allocation model without considering, on a customer-by-customer basis, exactly what types of assets are used to serve them.

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64 Transcript Volume 2, page 65
65 Energy+ response to VECC-TCQ-7 c).
66 Transcript Volume 1, page 130
67 Energy+ response to TMMC IR 15.4
68 Transcript Volume #1, pages 139-140
69 AIC, page 21
70 These treatments are evident from the cost allocation model (JP-11) filed with TMMC's Updated Evidence (February 219)
71 TMMC Updated Evidence (February 2019), page 17
72 AIC, page 21

3.41 Again, this approach is consistent with a services or pooling approach to cost causality and cost allocation. In cross-examination[73] Ms. Newland sought to establish that the fact certain customers are allocated the costs of underground facilities when they don't use them represented a "flaw" in the Board's cost allocation model. VECC submits that the Board's model is not flawed and does reflect cost causality. However, it posits a different approach to cost causality (i.e., a "pooling" approach) than that proposed by Mr. Pollock.

3.42 In fact, Mr. Pollock applies both the Board's approach and his different approach in his evidence. He applies the asset specific approach when allocating the costs of distribution assets to TMMC[74]. However, he applies the pooling approach when allocating the cost of distribution assets to other customer classes[75]. In VECC's submission if there is a flawed approach it is in the selective application of methodologies used by Mr. Pollock.

3.43 Either a "pooled" approach should be used for all distribution assets or a "specific asset" approach should be used. In this regard, VECC agrees with Energy+'s view[76] that by not allocating TMMC the costs associated with any underground facilities and not adjusting the demand allocation for poles to recognize that there are loads in other customer classes that are served using underground facilities, Mr. Pollock's approach results in TMMC being cross-subsidized by other Energy+ customers that use primarily underground assets to receive service. In order to be fair to all customer classes it is essential that a common approach to cost causality/cost allocation be applied.

3.44 However, applying Mr. Pollock's "specific asset" approach to all customer classes is problematic from a practical perspective as Energy+ has indicated[77]:

> The effort involved in providing a breakdown, for each customer class, of the load (kWh) served by overhead versus underground primary distribution facilities would be significant. It is difficult to extract this level of granular information from Energy+'s GIS system. In addition, there would be a significant challenge in correlating the information in the GIS system to the Billing system to obtain load (kWh) data for each customer class.

3.45 Furthermore, applying Mr. Pollock's "specific asset" approach would require more than just distinguishing between customers' use of overhead versus underground facilities. TMMC is not the only Energy+ customer who is served via radial facilities rather than through a looped supply such that they cannot be considered as receiving service from the integrated distribution network[78]. Application of Mr. Pollock's "specific asset" approach would require the identification of those parts of the system and the associated customers who are not "served"

[73] Transcript Volume 1, page 188
[74] The cost of poles is allocated to TMMC on the basis that it uses poles. However, the cost of underground facilities is not allocated to TMMC on the basis that it does not use these facilities.
[75] The cost of poles is allocated based on the total loads for each customer class, even though some of the load in the other customer classes is served using underground facilities.
[76] AIC, page 21
[77] VECC-TCQ-70 h)
[78] Transcript Volume 1, pages 131-132

from Energy+'s integrated network. The cost of the related assets would then have to be identified and allocated only to those customers that "use" the assets.

3.46 Even more problematic is that the logical extension of Mr. Pollock's approach would require recognizing that utilities with two or more distinct and geographically separate service areas would require a separate cost allocation for each. In Energy+'s case, the Cambridge-North Dumfries and Brant service areas are separate and there are no facilities that are owned by Energy+ that interconnect the two[79]. Application of Mr. Pollock's "specific asset" approach would require a separation of the assets that make up each service area's integrated distribution network so that they can be allocated solely to the customers served by each.

3.47 Not only would these distinctions make the cost allocation more difficult to perform but the approach and results would have significant policy implications since they would confound and be inconsistent with the objective of rate harmonization for distribution utilities that have consolidated. VECC submits that the Board should reaffirm the "pooling" approach to cost causality/cost allocation as used in the current version of the Board's cost allocation model.

3.48 In the case of Energy+, using a pooling approach in conjunction with a direct allocation of TMMC's dedicated feeders will require that adjustments be made to the load data associated with TMMC. Since only the feeders and not the poles are being directly allocated it is VECC's submission that the appropriate adjustment would be to exclude TMMC's load for the allocation of primary overhead feeder/conductor costs (USOA #1835-4) and primary underground conductors (USOA #1845-4). The rationale being that the costs of the feeders (i.e., the lines) used to serve TMMC are fully accounted for through direct allocation. However, since the primary poles that support the overhead conductor (USOA #1830-4) are still considered a shared cost to be allocated to all customers using primary service VECC submits that the cost associated with underground conduit (USOA #1840-4) that similarly supports the underground conductor should also be "pooled" and allocated to all customers including TMMC.

3.49 In VECC's view this will produce a fair allocation of costs that is consistent with the pooling approach to cost causality/cost allocation.

Embedded Distributor Cost Allocation

3.50 On March 4, 2019 the OEB issued a Decision stating that *"consideration of the adoption of a proposed alternative embedded distributor cost allocation methodology is out of scope in this proceeding*" (i.e., EB-2018-0028). However, in the same letter the Board requested that *"parties provide in their final submissions their recommendations as to the consideration and possible adjudication of this issue by the OEB on a going forward basis*".

3.51 In reaching its decision the Board referenced comments by Hydro One that the alternative approach to cost allocation for embedded distributors would be a significant departure from

[79] Transcript Volume 1, page 132

previous OEB decisions and the OEB's 2011 Report of the Board: Review of Electricity Distribution Cost Allocation Policy (the OEB's 2011 Report). The Decision also noted that "*the methodology employed 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, providing direction on how to allocate costs to embedded distributors, applicable to all utilities*".

3.52 VECC notes that, contrary to Hydro One's contention, the alternative approach explored in its interrogatories (i.e., allocate costs to the embedded distributors using the Board's cost allocation model) is not a significant departure from previous OEB decisions. Indeed, a review of the Board's decisions regarding 2017, 2018 and 2019 rates indicates that there were 7 host distributors that made cost of service based applications and filed a cost allocation study as part of their application. In all of the cases except for Energy+ the allocation of costs to the host's embedded distributor(s) was not done using Appendix 2-Q. The specific distributors involved are set out below and it is interesting to note that both of the host distributors for Energy+ (Brantford Power and Hydro One) are on the list:

- Energy+ (EB-2018-0028)
- Erie Thames Powerlines (EB-2017-0038)
- Essex Powerlines (EB-2017-0039)
- Hydro One Networks[80] (EB-2017-0049)
- Brantford Power (EB-2016-0058)
- Canadian Niagara Power (EB-2016-0061)
- E.L.K. Energy[81] (EB-2016-0066)

3.53 Also, as noted in VECC's letter of February 25, 2019 the current 2019 Filing Guidelines do not require the use of Appendix 2-Q if the host distributor has established a separate embedded distributor customer class. Indeed, the instructions at the top of Appendix 2-Q specifically state: "*Not required if Host Distributor has an Embedded Distributor rate class, i.e. a separate row on Sheet 11 of the RRWF*".

3.54 VECC submits that neither the current Filing Guidelines, the specific instructions regarding the use of Appendix 2-Q nor recent Board decisions support the use of Appendix 2-Q in those instances where a host distributor has established a separate Embedded Distributor customer class. To the contrary, they all support the full inclusion of Embedded Distributors in the cost allocation model. Furthermore, as can be seen from the recent proceedings cited above virtually all host distributors have already been taking this approach. As result, VECC submits that there is no need for "adjudication" on this issue on a going forward basis. Rather what is required is for the Board to reinforce in future Filing Guidelines the practice that it has already established and that distributors have generally been following for the last three years.

[80] Hydro One does not have a separate Embedded Distributor class. Rather Embedded Distributors are included in its ST class and allocated cost using the cost allocation model

[81] The only distribution asset associated with the embedded distributor is a meter which is directly allocated using the cost allocation model

D. RATE DESIGN, INCLUDING RESIDENTIAL RATE DESIGN (ISSUES 3.3 & 3.4)

3.3 Are the applicant's proposals for rate design appropriate, including the proposal for distribution rate harmonization?

3.55 Rate harmonization was an element of the Purchase Agreement the former Cambridge North Dumfries ("CND") agreed to as part of its acquisition of the former Brant County Power ("BPC") and a consideration in the Board's approval of the acquisition[82]. Energy+ proposes to harmonize the rates and adopt a single Schedule of Rates and Tariffs for all Energy+ customers. As part of rate harmonization, Energy+ is proposing to retain the GS> 50 to 999 kW customer class and GS >1,000-4,999 kW customer class that exist for the former CND service territory and to reclassify certain customers in the former BCP service territory to these rate classes. The former BCP maintained only a GS>50 kW rate class[83].

3.56 For each customer class the current (2018) rates are harmonized by using the 2019 forecast billing determinants for each service area to develop weighted average fixed and volumetric rates for the class[84]. The results are then used as the starting point for determining 2019 rates.

3.57 VECC submits that this is a reasonable methodology for implementing rate harmonization. VECC notes that apart from the USL and Sentinel Lighting customers in the former BCP service area and low volume residential customers in the former CND service area all other customers' total bill impacts are less than 10%[85].

3.4 Has the applicant appropriately applied the OEB's policy on residential rate design?

3.58 For Energy+, 2019 represents the fourth and final year of the transition to a fully fixed monthly service charge for the Residential rate class[86]. However, as noted above, the total bill impact on low volume residential consumers exceeds 10%. In light of this, Energy+ is proposing mitigation by deferring the transition to a fully fixed monthly service charge for the Residential class by one additional year to reduce these total bill impacts to less than 10%[87]. VECC submits, in light of the total bill impacts, Energy+'s proposal to extend the transition to a fully fixed rate by one year is reasonable and should be accepted by the Board.

E. RETAIL TRANSMISSION SERVICE RATES AND LV RATES (ISSUE 3.5), INCLUDING GROSS LOAD BILLING FOR RETAIL TRANSMISSION RATES FOR CUSTOMERS WHO HAVE LOAD DISPLACEMENT GENERATION (ISSUE 3.6)

[82] EB-2014-0217/2014-0023
[83] Exhibit 1, page 57
[84] Energy+ response to IR 8-VECC-52 a)
[85] Exhibit K1.6
[86] Exhibit 8, page 7
[87] AIC, pages 22-23

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

RTSR

3.59 Energy+ receives wholesale transmission service from metered points that are directly connected to the IESO controlled grid. Energy+ is billed Uniform Transmission Rates ("UTRs") by the IESO on all capacity delivered through these points[88]. Energy+ also receives power from two host distributors (Hydro One and Brantford Power) and in each case is subject to the host distributor's RTSR charges[89]. Energy+ passes these charges on to its customers through its OEB-approved Retail Transmission Service Rates. For 2019 Energy+ is proposing to harmonize the RTSR charges across its two service areas[90].

3.60 VECC has no concerns with Energy+'s proposal to harmonize its RTSRs or its approach for doing so. VECC notes that the harmonization of RTSRs is consistent with the "pooling" approach to cost causality/cost allocation discussed under Issue 3.2 as it pools the costs of providing each type of transmission service and recovers them from all customers using the service regardless of the specific service area where the customers are located in (i.e. CND or BCP).

3.61 In contrast, the harmonization of RTSRs is incompatible with the "specific asset" approach to cost causality/cost causation which, if extended to RTSRs, would require each service area's RTSR rates to be calculated separately recognizing the charges associated with the specific delivery points to each service area.

3.62 Energy+ proposes to apply its RTSRs to all customer classes with the exception of one embedded distributor – HON#2[91]. Energy+ receives the power it supplies to HON#2 from an HON owned LV feeder (i.e., a point where Energy+ is embedded in HON). This exception arises as a result of a "billing" arrangement with Hydro One whereby Hydro One only assesses its RTSR charges to Energy+'s portion of the load (i.e. excluding the deliveries to HON#2). In turn, Energy+ does not apply any RTSR charges to HON#2[92].

3.63 VECC has no issues with Energy+'s proposal to apply its RTSRs to all customer classes except HON#2. Again, VECC would note that the recovery of transmission service charges from all customers is consistent with the "pooled" approach to cost causality/cost allocation. However, if the Board does not accept the recovery of Energy+'s bulk costs on similar "pooled" basis as proposed by Energy+ (and supported by VECC) then the basis for allocating and charging RTSRs to customer classes would need to change. Under such circumstances the loads used to allocate and charge RTSRs to each customer class would have to be adjusted to exclude the portion of the load served from Energy+'s bulk facilities.

[88] AIC, page 23
[89] See the CND and BCP RTSR WorkForms
[90] Exhibit 8, page 16
[91] AIC, page 23
[92] TC Undertaking JTC1.4

LV Costs

3.64 Contrary to Energy+'s Argument in Chief, LV costs are not "allocated to each rate class based on the proportion of proposed retail transmission connection revenue collected from each class" [93]. Table 8.14 in Exhibit 8 of the initial Application sets out the allocation of LV cost to customer classes and it is evident that the embedded distributor classes are excluded from the allocation of LV costs. This was confirmed during the oral hearing[94].

3.65 During cross examination counsel for Hydro One sought to confirm whether any of the embedded distributors received their supply from connections to one of Energy+'s host distributors such that their loads attracted LV charges (or ST charge in the case of HON) from the host distributor [95]. VECC anticipates that HON may argue that embedded distributor load contributes very little (or nothing) to the LV charges incurred by Energy+ and therefore it is appropriate that they be excluded from the allocation/recovery of Energy+'s LV costs.

3.66 In VECC's view such a position would be founded on the same view of cost causality as put forward by Mr. Pollock – namely if a customer/customer class does not use an asset then it should not be allocated any of the associated costs. If the Board accepts this argument then, for reasons of fairness and consistency, the allocation of LV costs to other classes should also exclude the portion of the load for each class that is not served from connections to Energy+'s host distributors. This approach would be fundamentally different from that currently approved by the Board and where the allocation is based on the RTSR revenues for each customer class which are calculated based on the class' total load[96]. The current approach (i.e. allocation based on RTSR charges using each class' total load[97]) is based on a "pooling" approach – the same approach as is used for RTSR and the OEB-approved cost allocation methodology.

3.67 In the interest of fairness and consistency, VECC submits that embedded distributors should be allocated a share of LV costs using the same approach as is currently used for all other classes.

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

3.68 Energy+ is proposing to bill the RTSR to customers with load displacement generation RTSR on a gross load billing basis. The reason is that it directly aligns the amounts charged to those customers with what is actually being charged to Energy+ by the IESO for UTRs associated with that load displacement generation[98].

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[93] Page 25
[94] Transcript Volume 1, page 127
[95] Transcript Volume 1, page 133
[96] Transcript Volume 1, page 127
[97] Filing Requirements For Electricity Distribution Rate Applications- 2018 Edition for 2019 Rate Applications, Chapter 2, page 55
[98] AIC, page 23

3.69 Mr. Pollock did not address the issue of RTSR in his evidence[99]. However, in their testimony the TMMC witnesses referenced a previous Guelph Hydro application[100] and the fact the Board had put the issue of gross load billing for RTSRs in abeyance. The witnesses expressed the view that the matter should await the outcome of the Board's policy review.

3.70 Subsequent to Guelph filing its application, the Board issued a letter on March 29, 2016 regarding the billing of customers with load displacement generation. It states in part:

> 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).

3.71 VECC notes that on February 21, 2019 the Board released a Staff Report to the Board: Rate Design for Commercial and Industrial Customers to Support an Evolving Electricity Sector (EB-2015-0043) and it does not deal at all with the question of gross load billing for RTSRs. Furthermore, to VECC knowledge the Board has not initiated a separate process to deal with gross load billing for RTSRs. In light of the passage of time and the uncertainty as to when this issue will be dealt with on a generic basis, VECC submits that it is reasonable to address Energy+'s proposal to bill customers with load displacement generation RTSR on a gross load billing basis in this proceeding and not defer the matter.

3.72 Overall, VECC agrees with Energy+'s reasoning[101] as to why gross load billing of RTSRs is appropriate and submits that the Board should accept its proposal.

STANDBY CHARGE FOR CUSTOMER CLASSES WITH LOAD DISPLACEMENT GENERATION (ISSUE 3.7)

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

3.73 Energy+ is proposing to implement a new Standby charge for all GS 50-999kW, GS 1000-4999kW, and Large Use customers that have load displacement generation and that require Energy+ to act as a backup supply of electricity in the event the load displacement generation is unavailable. Energy+'s proposal is to utilize a "contract capacity" methodology for standby whereby the customer contracts for a peak load requirement (the "Contracted Capacity"). On a monthly basis, if the customer's actual peak load is greater than or equal to the Contracted

[99] Transcript Volume 2, page 63
[100] EB-2015-0380
[101] AIC, pages 23-25

Capacity, the customer is charged the volumetric rate on the actual load. If the customer's actual peak load is less than the Contracted Capacity, the customer is charged on the actual load at the volumetric rate plus a standby rate (which is based on the volumetric rate for that class) on the difference between the Contracted Capacity and the actual load. In the current Application Energy+ has proposed as Contracted Capacity value for TMMC based on historical data[102] regarding maximum annual demand.

3.74 In his evidence Mr. Pollock has proposed an alternative Standby Charge that would consist of two parts:

i. A Contract Volumetric Rate that would be applied monthly to a set contract amount regardless of the actual standby usage. In principle this rate would be based on the costs associated with local[103] or customer specific facilities[104]. Mr. Pollock has proposed a contract amount of 6.9 MW based on a history of TMMC's incremental demand when one of its generation units was out of service during the peak period[105].

ii. A Daily Volumetric Rate that would be applied to the product of: i) the maximum incremental demand in the month when one or more generation units are out of service during the peak period and ii) the number of peak days there was an outage[106]. The daily rate would be designed to recover the full cost of shared facilities assuming the generation outage lasted for the full month (i.e., 20.9 peak days)[107]. Overall, if the customer needed Standby for the entire month that customer would pay the same total charges as a non-generating customer taking service out of the same rate[108].

3.75 In VECC's view there are serious flaws/shortcomings with both Energy+'s and Mr. Pollock's proposals. In the case of the Energy+'s proposal the major difficulty is that the customer's monthly bill will be based on the Contracted Capacity without reference to the actual load level or the reasons why the actual load varies from the Contracted Capacity[109]. This does not recognize that a customer's total load requirements can vary over the year due to changes in operations for reasons totally unrelated to its requirements for Standby. This may result in the Standby rate being applied to a quantity (i.e., the difference between the Contracted Capacity and the actual load) that exceeds the nameplate rating of its generation. Indeed, a review of the 2016 data initially used to set the Contract Capacity indicates that there was one month where the difference did exceed the installed capacity of the customer's generation[110]. In

[102] Energy+ response to TMMC IR 4-4
[103] TMMC Updated (February 2019) Evidence, page 26
[104] Transcript Volume 2, page 50
[105]TMMC Updated (February 2019) Evidence, page 28 and Transcript Volume 2, page 55
[106] TMMC Updated (February 2019) Evidence, pages 28-29 and TMMC response to VECC TCQ 7 a) & d)
[107] TMMC Updated (February 2019) Evidence, page 30
[108] Transcript Volume 2, page 51
[109] Transcript Volume 1, page 98
[110] Energy+ response to 7-Staff 84 a)

VECC's view such a result would be inconsistent with the objective of Standby rates. The Standby rate should be set so as to recognize the cost incurred by the utility as result of having to have the capability to meet customer demands normally supplied by its own generation.

3.76 Mr. Pollock's approach addresses this shortcoming in Energy+'s proposal by setting the contract value based on the additional load requirements during periods of generation outage. However, there are other issues with his proposal:

- First, Mr. Pollock's definition of what are local versus shared distribution facilities for purposes of respectively setting the contract and daily rates is far from clear. In his initial evidence (filed September 27, 2018) all facilities either directly assigned to TMMC (i.e., the feeders) or allocated on a non-coincident peak basis (i.e., the shared poles) were considered local facilities and included in the cost to be recovered through the rate applied to the contract quantity[111]. However, in his updated February 15, 2019 evidence regarding the Standby Rate design for the TMMC Large Use class, only the directly assigned feeders are considered to be local distribution facilities and used as the cost basis for the rate to be applied to the contract quantity[112]. In the updated evidence, the Standby Rate design for the TMMC Large Use class now considers the poles to be shared distribution facility and they are used as the cost basis for the Daily Volumetric Rate. In contrast, for the illustrative GS 50-999 Standby Rate provided in the February 2019 evidence, the poles are still considered to be a local distribution facility and included in the derivation of the Contract Volumetric Rate[113].

  Clarification as to the criteria to be used in distinguishing between local distribution facilities and shared distribution facilities was sought both through interrogatories[114] and cross examination[115]. However, no clear criteria were forthcoming. In VECC's view a clear definition of local vs. shared distribution facilities is fundamental to a fair and consistent implementation of Mr. Pollock's Standby Rate proposal across customer classes and across utilities.

- Second, Mr. Pollock has limited his identification as to when Standby is required to just peak days and to just those times when one or more generation unit is out of service. Under his cost allocation proposals shared distribution costs (i.e., the poles) are allocated to TMMC using the 4NCP demand allocation factor. Since, Energy+'s monthly peaks can occur in the off-peak as well as the peak period[116] it is not clear why Standby requirements in the off-peak period are not also relevant. Similarly, the evidence submitted by Ms. Melody Collis[117] indicates there were numerous hours where both

[111] Page 50
[112] Page 27
[113] Page 29
[114] TMMC responses to 2nd round interrogatories, VECC 7, 8 and 15
[115] Transcript Volume 2, pages 83-85
[116] Energy+ response to VECC TCQ-81 c)
[117] Schedule MC4

generators were operating (i.e., total generation output exceeded the capacity of a single generator) but total output was less than the overall capability of the two generators. During such periods, Energy+ would effectively be providing Standby service to make up the difference. Again, it is not clear why Mr. Pollock has excluded these hours from the determination of when Standby is used.

- Third, in deriving the Daily Volumetric Rate, Mr. Pollock assumes that there is a linear relationship between Standby load requirements and TMMC's monthly peak. When asked about this, brief reference was made to the "Bary Curve" as being the basis for the assumption[118]. However, no further details were provided and there was no indication given as to whether the Bary Curve itself was typically based on a linear relationship. Furthermore, an inspection Schedule JP-7 from Mr. Pollock's evidence shows no demonstrable historical relationship between the number of days of outage and the contribution to TMMC's monthly peak made by the Standby load requirements.

3.77 At this point, VECC is unable to support either Standby proposal. VECC notes that the recently released Staff Report to the Board - Rate Design for Commercial and Industrial Electricity Customers: Rates to Support an Evolving Energy Sector – specifically addresses the issue of Standby rates. VECC submits that the Board should endeavour to complete this work as soon as possible.

[118] TMMC response to 2nd round interrogatories, VECC 14-4

4. GROUP 2 DEFERRAL AND VARIANCE ACCOUNTS (ISSUE 4.2)

4.1 Three issues are discussed with respect to Deferral and Variance Accounts: LRAMVA, OEB Assessment Fees, the Costs Incurred in the Transition to Monthly Billing. VECC also makes submission with respect to the appropriate disposition of the accounts

OEB Assessment Fees

4.2 As per Table 9-16 below Energy+ is was initially seeking $174,428 in incremental OEB costs associated with the change in the Board's assessment methodology[119].

Table 9-16: OEB Assessment Fees

	Fees Paid	Fees Paid based on Last Rebasing Year			
2016	**2016 Actual**	**CND 2014**	**BCP 2011**	**Combined**	**Variance Account**
Apr 1 - June 30	71,059	37,708	10,290	47,998	
July 1 - Sept 30	71,059	37,708	10,290	47,998	
Oct 1 - Dec 31	71,052	36,842	9,825	46,667	
	213,170	112,258	30,405	142,663	70,507
2017					
Jan 1 - Mar 31	**2017 Actual**				
Apr 1 - June 30	71,052	35,798	9,970	45,768	
July 1 - Sept 30	73,459	37,708	10,290	47,998	
Oct 1 - Dec 31	73,459	37,708	10,290	47,998	
	69,563	36,842	9,825	46,667	
	287,533	148,056	40,375	188,431	99,102
Principle	$ 500,703			$ 331,094	$ 169,609
Carrying Charges					$ 4,819
Total					$ 174,428

4.3 VECC position on this issue has been consistent in a number of previous cost of service cases. The purpose of the account was to capture the variance as between the prior and new methodology employed by the Board for cost assessment (customer number vs. volume of sales and other changes[120]). However, Energy+ does not distinguish in the variance account between the variance caused by the change in methodology and the natural variance that occurs as between the last cost of service forecast of OEB assessment cost and actual cost. As a result it is indeterminate what amount of the $174k sought is actually due to the Board's policy change. In any event the amount sought is below the Utility's materiality threshold of $175,000.[121]

4.4 In VECC's submission the OEB Assessment Fee variance should not be disposed of to the debit of customers and instead the account should be closed without disposition.

[119] Exhibit 9, page 30 of 80
[120] Ontario Energy Board Cost Assessment Model, April 1, 2018
[121] See Exhibit 1, page 164 of 1145

4.5 Energy+ is also seeking to recover $511k in incremental costs incurred in the transition to monthly billing as set out in Table 9-15 below[122]:

Monthly Billing

Table 9-15: Costs Incurred to Transition to Monthly Billing

Incremental Monthly Billing Costs	2016	2017	Total
Labour Costs	54,436	80,815	135,251
Postage Costs	39,281	204,323	243,604
Envelopes and Stationery	12,090	62,884	74,974
Consulting Services	18,515	-	18,515
Advertising to Customers	4,586	-	4,586
Other Expenses	3,361	17,696	21,057
Total	$ 132,268	$ 365,718	$ 497,986
Carrying Charges to December 31, 2018			13,463
Balance in Account			$ 511,449

4.6 Subsequent to the settlement conference in its updated evidence Energy+ made changes with respect to the costs it was seeking for recovery. In this update it acknowledged the cash-flow benefit that resulted from the change from bi-monthly to monthly billing and made an adjustment to seek a total of $416,346. This reduction took into account an estimated cash flow benefit of moving to monthly billing of $91,237 and a related change to carrying costs of $3,866[123].

4.7 What is not clear is how the adjustment of $91k relates to the change in working capital. This issue was explored by SEC during the hearing. At that time Energy+ admitted it had not adjusted the amount sought for the savings in working capital from bi-monthly to monthly billing in 2016 and 2017. Energy+ argued that there was no way to make an estimate of these savings. However, in their detailed cross-examination of the issue SEC demonstrated that changes to the service lag might result in a savings of $241k[124].

4.8 VECC has reviewed and supports the arguments of SEC in this matter. We note that in their argument SEC makes an adjustment for the evidence provided by Energy+ at the hearing. This adjustment has the effect of reducing the $241k adjustment. In our

[122] Exhibit 9, page 28 of 80

[123] Updated Evidence December 13, 2018, Exhibit 9, page 28 of 80

[124] Volume 1, March 7, 2019, pages 78 -89

submission the amount calculated for recovery by SEC of $319,235 for the 2016/17 period is reasonable and takes into consideration all the evidence provided by the Applicant..

LRAMVA

4.9 Energy+ is requesting approval for the recovery of LRAMVA balances attributable to Energy Efficiency Programs as of December 31, 2017 in the amount of $1,545,771. During the discovery process a number of questions were asked by Board staff and intervenors with respect to the computation and recovery of the LRAMVA related to: (i) a large user generation project undertaken as part of the IESO's Process and Systems Upgrade Initiative ("PSUI"), which was in-service as of December 2015; and (ii) a streetlighting project. The proposal for recovery of the LRAMVA related to the large user generation project was also raised during the oral proceeding[125].

4.10 In computing the LRAMVA claim for the generation project, Energy+ proposes an alternative computation for the demand savings attributable to this project. Rather than the EM&V average demand savings figure, as reported by the IESO, Energy+ proposes utilizing actual metering data to establish the impact of the generation project. Energy+ has Measurement Canada approved meters installed to measure: (i) the quantity of power taken by the customer from Energy+'s distribution system; and (ii) the output of the generation facility for each hour of the month. Using this hourly data Energy+ is able to determine the actual billing demand reductions attributable to the load displacement generation. VECC agrees with Energy+'s submission that the alternative computation represents a verifiable proxy for lost revenue to Energy+ attributable to the generation project[126]. VECC submits that the Board should accept Energy+'s computation for purposes of its LRAMVA claim.

4.11 During the oral proceeding TMMC's witnesses questioned whether the lost revenue from the load displacement generation project should be recovered from the Large Use class as current Board policy requires[127]. The suggestion was that while such an approach may be appropriate in the case of Residential customers and incentive programs for light bulbs, it was not appropriate for large projects. From VECC's view the principle is the same in both instances. In the case of light bulbs, if all Residential customers participate and the impacts were not anticipated in the load forecast used to set the class' rates then, through the LRAMVA, the incentive will effectively be "clawed back". Alternatively, if only some Residential customers participate then those who don't will be responsible for a portion of the LRAMVA claim although they received no direct benefit. In VECC's submission it would be a fundamental deviation from Board policy and patently unfair to some customers for the LRAMVA claim to be recovered from any customer classes other than the customer class representing the customer(s) participating in the project. In VECC's view the magnitude of the claim is an irrelevant factor in the application of the Board's policy in this matter.

[125] Transcript Volume 2, pages 41 and 109
[126] AIC, pages 30-31
[127] Transcript Volume 2, pages 41-42

4.12 In the case of Streetlighting, Energy+ has proposed a methodology to compute the estimated demand savings for this project utilizing actual streetlight billing demand reductions and provided detailed computations of the demand savings for the streetlight project[128]. VECC submits that the methodology utilized by Energy+ in computing the Streetlighting billing demand reductions should accepted by the Board for purposes of its LRAMVA claim.

5.0 Reasonably Incurred Costs Open

5.1 VECC respectfully submits that it has acted responsibly and efficiently during the course of this proceeding and requests that it be allowed to recover 100% of its reasonably incurred costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

MARCH 29, 2019

[128] Energy+ response to Staff-TCQ-#5