PUBLIC INTEREST ADVOCACY CENTRE
LE CENTRE POUR LA DÉFENSE DE L'INTÉRÊT PUBLIC

August 13, 2018

VIA E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: Hydro One Networks Inc. EB-2017-0049
Vulnerable Energy Consumers Coalition (VECC) Submissions

On behalf of the Vulnerable Energy Consumers Coalition (VECC) we have attached their Submission with respect to the above-noted proceeding.

We apologize for our delay in filing of same but this was due to the fact that VECC Counsel is out of the country and there were some other delays in coordinating our response.

As per Procedural Order No. 7 we have forward a copy of VECC Submission to the Applicant, as well as their Counsel and all registered parties via e-mail.

Yours truly,

Ben Segel-Brown

Counsel for VECC

Cc: List of Intervenors

Benjamin Dean Segel-Brown Professional Corporation
Tel: 613-864-6322. E-mail bsegel-brown@piac.ca.
1204-ONE Nicholas Street, Ottawa, ON K1N 7B7 Fax: 613-562-0007

EB-2017-0049

ONTARIO ENERGY BOARD

Hydro One Networks Inc.

Application for Electricity Distribution Rates
January 1, 2018 - 2022

Final Submission
of the
Vulnerable Energy Consumers Coalition
(VECC)

13 August 2018

Ben Segel-Brown, Counsel for
Vulnerable Energy Consumers Coalition

Public Interest Advocacy Centre:
1 Nicholas Street, Suite 1204
Ottawa, ON K1N 7B7
613-562-4002
piac@piac.ca

Direct:
bsegel-brown@piac.ca
613-864-6322

A. GENERAL

1. Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

VECC has no specific submission with respect to this issue. We are not aware of any outstanding directions of the Board from previous proceedings that have not been addressed in this application.

2. Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

VECC has no specific submissions with respect to any customers concerns expressed at the Board held community meetings. We would note however that at these meetings only the Applicant and Board staff presents information to the community. The Board does not express an opinion on the application. The result is that attendees are largely unaware of any relevant issues or alternatives available upon which the Board might modify the applicant's proposal. The venue is only for the Board to explain its role and the Utility to convince ratepayers of their case. In our view these meetings serve the purpose of being seen to have public engagement without actual engagement with an objective of soliciting meaningful input into the Board's decision making.

A cursory review of the letters of the some 3000 letters of comment and a read of the OEB Staff Summary of Community Meetings[1] shows customers are generally exercised about the same things – the high cost of electricity, a perception that compensation, especially executive salaries, are excessive, and scepticism as to the efficacy of the Fair Hydro Plan.

As a practical matter these issues have little bearing on the setting of distribution rates. Even issues which do have an impact on the calculation of rates, such as compensation, are usually misunderstood in their materiality. In such circumstances the result is ultimately a reflection of political rather than practical sensibilities and of little relevance to the Board's work.

This is not particularly a Hydro One issue, but one faced continually by VECC in reviewing the OEB required customer engagement activities of utilities. Hydro One, due to its customer and service territory size spends inordinately more on an activity we think not only of marginal value but one which gives to consumers a false sense of their ability to impact change.

[1] Hydro One Networks Inc. Application for 2018-20122 Distribution Rates, September 7, 2017

In our submission the Board should adjust the agenda of future so as to allow opportunity for intervenors or other interested parties to provide their own analysis of the Applicant's proposal. This would provide ratepayers, especially residential and small commercial customers to better understand the issues to be dealt with in the proceeding. In our view the result would be more informed and meaningful engagement of consumers who could offer informed and relevant input.

3. Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

No. The amount is excessive since it rebases in 2018 on an artificially high rate base and adjusts future year's rates on an overly generous basis. The capital spending suggested during the rate plan period is clearly excessive.

In our submission the rate adjustment formula is deficient and will lead to, if approved, higher rates than are necessary to ensure the safe and reliable operation of Hydro One's distribution system.

4. Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

It follows from our submission on Issue 3, that in our opinion, they are not.

5. Are Hydro One's proposed rate impact mitigation measures appropriate and do any of the proposed rate increases require rate smoothing or mitigation beyond what Hydro One has proposed?

Generally, HONI's rate impact mitigation proposals are appropriate. We do have make the observation that it is not clear why the capital spending program (at whatever level approved) could not be spread uniformly during the rate plan period.

Based on HONI's December 2017 Update, the 2018 revenue requirement reflects an increase of 3.1% over 2017 OEB-approved levels. After adjusting for the reduced load forecast (3.0%), the resulting average impact on distribution rates is an increase of 6.1% in 2018, and an average of 3.4% per annum over the CIR term. In comparison, in the June 2017 update, the average impact on distribution rates in 2018 was 4.9%, an average of 3.5% per annum over the CIR term[2].

HONI did not update its bill impact calculations for the December 2017 Update[3]. Based on the June 2017 Update, the total bill impacts to be experienced by the average customer in most customer classes will be less than the Board's 10% bill impact criterion.

For the DG class, the annual bill impacts were limited by phasing in the required adjustment to the class' revenue to cost ratio. For the new acquired AUGe, AUGd, AR, AGSe and AGSd classes, HONI also proposes to move the revenue to cost ratios to within the Board's approved range in a manner that limits either the total distribution impacts or total bill impacts to a level that is consistent with Hydro One customers' similar rate classes. This approach will result in total bill impacts well below the 10% total bill impact threshold specified by Board[4].

For three of the customer classes of the acquired utilities (street lighting customers, sentinel light customers and unmetered scattered load customers) where the bill impacts would otherwise exceed 10% HONI is proposing rate mitigation in the form of a bill credit for those customers within these rate classes that are experiencing rate increases to ensure that they will not experience total bill impacts greater than the mitigation threshold[5].

VECC has no other issues with HONI's rate mitigation proposals.

6. Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

In this proceeding and others Anwaatin Inc. has raised the issue of system reliability of service to and in First Nation communities. In our submission the Board should direct Hydro One in its next cost of service filing to explicitly provide evidence with respect to the reliability in, and capital programs for, First Nation communities served by the Utility.

---

[2] Exhibit Q, Tab 1, Schedule 1, page 3
[3] Exhibit Q, Tab 1, Schedule 1, page 4
[4] Exhibit H1, Tab 4, Schedule 1, page 6
[5] Exhibit H1, Tab 4, Schedule 1, page 7

B. CUSTOM APPLICATION

7. Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Hydro One is proposing neither a price cap nor a revenue cap, but rather a "revenue requirement adjustment formula". Board Staff rightfully note in their argument that Hydro One has mischaracterized the proposal as a revenue cap, but then go on to conclude the distinction is not significant[6]. This is not correct -the difference between a revenue and revenue requirement cap is important and material in this proceeding.

A price cap is to breaks the link between utility costs and utility prices. This decoupling is what underlies the entire incentive mechanism of the plan. Furthermore a price cap is to be preferred because it provides the most straightforward link between to the cost facing ratepayers. Theoretically a properly constituted revenue cap can achieve the same results but in a less straightforward manner. One complexity is that if revenues, rather than prices are adjusted then one has to consider the impact of customer growth separately. As pointed out by Board Staff and their sponsored expert Mr. Lowry the lack of a customer growth factor in Hydro One's proposal is a major deficiency in the rate adjustment formula. Hydro One's proposal to fix to adjust or mitigate the lack of a growth factor through using a fixed (at temporarily) load forecast does address this issue.

Board staff have made detailed argument with respect to the lack of a growth factor in the formula. We agree generally with these arguments though we are less convinced of some of the speculative aspect including the idea that there are any significant incremental OM&A costs to new customers. In any event we endorse the addition of a growth factor to the rate adjustment formula.

Inflation

Ultimately what customers want are for real rates to be steady or declining. In our view this basic tenet often gets lost in esoteric arguments about the appropriate inflation rate or 'X' factor. In the same way that consumers are not interested in the input prices to making bread but in the price of bread, ratepayers are only interested in the rates they are paying and how any increase in those prices stack up against the rate of inflation in their own wages.

This is why VECC primarily focuses on the CPI inflation rate. In our view employing industry specific input price inflators suffer from circular. If the input prices of providing electricity distribution service rise above the general inflation rate the issue is not, in our

[6] OEB Staff Submission EB-2017-0049, August 3, 2018, pg. 16

mind, to compensate the Utility for that premium, but rather to drive the Utility to find efficiencies to contain its costs. Take the largest component of utility costs – compensation. If the compensation rate for utility employees exceeds the average increase in compensation in the economy as a whole then an inflation factor which weighs these costs more heavily simply passes on these monopoly costs to the consumer. This leaves the ratepayer paying for the increased compensation costs twice – once in the rebasing exercise and again in the input related inflation rate used to adjust, in this case the revenue requirement.

The Board's hybrid inflation factor anticipates to some extent this argument. In any event as a practical matter there would appear to be little difference between the Board hybrid inflation factor and the CPI.

X-Factor

The sole nod to "incentives" in the proposed rate setting methodology is the incorporation of a 0.45% stretch factor. Board Staff have made lengthy submissions on the differences in the details of the methodology employed by PSE and PEG in their derivations of a stretch factor. In the end result both consultants agree on the final number. This is not surprising since both consultants employ essentially the same methodology.

In our submission there is nothing inherently incorrect in the stretch factor methodology employed by the consultants. However both studies project an undeserved level of accuracy in their numerical outcome. The data sets employed and the measurement errors inherent in such work make the accuracy of the results suspect. One could also argue as to the theoretical underpinnings of these studies which are not widely practiced by the work largely of a small group of consultants all originating in the same academic institution.

We make this point not to argue against use of the 0.45% stretch factor per se but to argue that the Board has more leeway than using this variable to adjust the inflationary impact of the resultant rates. As we have argued ratepayers are seeking the end resultant rate to be no higher than the overall rate of inflation. On its own the consensus X-Factor would achieve that objective. However the revenue requirement rate adjustment formula makes further increases for capital additions.

In our submission the Board should not hold itself to an adjustment of only .45% just because these two consultants have employed a methodology that provides a similar outcome. The Board has much wider discretion. It is conceivable for example for the Board to determine that efficiency is best served by reducing the measure inflation rate adjustment by some other amount and for some other objective. The fact that Hydro

One's cost of service on a customer basis are the highest of any large utility in Ontario is reason to do so.

In our submission the Board's objective, regardless of the rate plan submitted, should be to hold real rates steady. That is customers should not face an increase in their rates beyond the rate of inflation (however measured). Such an outcome would be also be consistent with the Fair Hydro Plan and the policy statements of the newly elected Ontario Government.

On its own a 0.45% reduction in the inflation rate through the X-factor would not achieve this result.

In our submission the capital factor needs to be eliminated. This could be done in one of two ways. The most straightforward is a reduction in the capital spending plans of the Utility. The other would be to adjust the total formula in any year to achieve a revenue requirement increase no greater than the post period rate of rate of inflation. Or a combination of the two.

Hydro One should be subject to a higher stretch factor. The OEB "Handbook for Utility Rate Applications" (2016) clearly indicates that utilities should be proposing <u>higher</u> stretch factors than those set by OEB benchmarking:

> It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.[7]

Hydro One will also benefit from an illusory productivity increase associated with averaging in acquired utilities. Because the utilities acquired by Hydro One are generally more efficient than Hydro One, averaging in the cost performance of those utilities will create a small but significant increase in average cost efficiency for Hydro One, even if no cost-savings are realized from the acquisition. A higher stretch factor should be set to incorporate the productivity enhancements that will result from averaging in more efficient acquired utilities.

8. Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

VECC's submission on this issue are made under issue #7.

[7] OEB "Handbook for Utility Rate Applications" at 26.

9. Are the values for the proposed custom capital factor appropriate?

VECC submits the Board should not approve the custom capital factor as it is not consistent with the principles of incentive rate making and does not follow the intent of the RRFE framework.

As we have noted the current proposal is not a "revenue cap" but rather a "revenue requirement adjustment" formula. This methodology largely eliminates the basic underpinnings of incentive rate making which is to decouple costs from rates. It is in facts more akin to an annual cost of service adjustment. It is only capped in any sense by the level of capital spending which ultimately drives all the future rate increases.

We are bit unclear as to what amount Hydro One is seeking to recover under its proposed plan. This is due to the apparent anomaly or difference in how line 14 of the Revenue Requirement table was calculated in the original filing and then subsequently in the evidence. Below is the most recent version of Table 2 filed as part of the hearing undertakings.

Our understanding is that Hydro One is seeking to recover the total revenue requirement as shown in line 11 of Table 2.

Table 2RR: Summary of Revenue Requirement Components ($ Millions)

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,649.9	8,009.4	8,412.0	8,940.7	9,306.4
2	Return on Debt	E1-1-1	198.6	208.0	218.4	232.0	241.5
3	Return on Equity	E1-1-1	275.4	288.3	302.8	321.7	334.9
4	Depreciation	C1-6-2	398.2	419.3	434.1	453.1	466.8
5	Income Taxes	C1-7-2	65.2	68.7	71.3	78.6	79.2
6	Capital Related Revenue Requirement		937.4	984.3	1,026.6	1,085.4	1,122.4
7	Less Productivity Factor (0.45%)			(4.4)	(4.6)	(4.9)	(5.1)
8	**Total Capital Related Revenue Requirement**		**937.4**	**979.9**	**1,022.0**	**1,080.5**	**1,117.3**
9	OM&A	C1-1-1	576.7	581.1	585.4	589.8	605.1
10	Integration of Acquired Utilities	A-7-1				10.7	
11	**Total Revenue Requirement**		**1,514.2**	**1,561.0**	**1,607.4**	**1,681.0**	**1,722.4**
12	Increase in Capital Related Revenue Requirement			42.5	42.1	58.5	36.8
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.80%	2.70%	3.64%	2.19%
14	Less Capital Related Revenue Requirement in I-X			0.46%	0.47%	0.48%	0.48%
15	**Capital Factor**			**2.34%**	**2.23%**	**3.16%**	**1.71%**

Source Undertaking J1.10 (VECC)

The second table, we have labelled Table 2S – though it is also labelled Table 2 in the original evidence. It shows a summary of the various factors in the $RCI = I - X + C$ formula. In the original exhibit both the annual revenue requirement in line 11 and the summation of the factors in Tables 2 were of equal value[8]. In the subsequent December 2017 update and the hearing update the change in line 11 and the sum of the estimated change in they do not and this is because how line 14 is calculated.

Table 2S: Custom Cap Index (RCI) by Component (%)

Custom Revenue Cap Index by Component	2019	2020	2021	2022
Inflation Factor (I) *- forecast -*	1.90	1.90	1.90	1.90
Productivity Factor (X) *– fixed -*	-0.45	-0.45	-0.45	-0.45
Capital Factor (C) derived from Table 2 above	2.34	2.23	3.16	1.71
RCI calculated using CF in J1.10 (table 2 above)	3.79	3.68	4.61	3.16
Actual Change In RR based on J1.10 (table 2 above)	3.09	2.97	4.58	2.46

Source: Exhibit A, Tab 3, Schedule 2, pg.7 as adjusted for Undertaking J1.10

Since the OM&A, productivity factors and capital expenditures forecasts are fixed (subject to capital spending variance accounting) the only variation in the formula lies in the actual versus forecast expected rate of inflation.

It is possible we are misunderstanding the proposal but we believe in the end result Hydro One is seeking recovery of the revenue requirement shown in line 11 of Table 2. If that is the case, and if the actual revenue requirement adjustment is calculated on the basis of the formula (rather than the basis of the forecast), then the only risk inherent in the formula is variability in inflation.

The lower actual inflation than expected the more the capital factor is affected. To see this one only image that inflation is zero during the term of the plan. Using Table 2S we can see that the variance – say in year 2019 between the required revenue requirement and the CF adjusted revenue requirement is 70 basis points (3.79-3.09).

In other words, in each year of the plan at a certain inflation factor (around 1.25%) the Utility will exceed its expected revenue requirement.

All of which begs the question if the required revenue requirement in each year of the plan is as set out in the last row of Table 2S then why not simply average the adjustment (approximately 3.3% per annum) and apply that figure to the 2018 revenue requirement?

[8] See the Updated Evidence 2017-06-07; Exhibit A, Tab 3, Schedule 1, page 7 and Schedule 2 page 7

This would require the Utility to smooth its capital plan somewhat, but the end result is identical to the application of the formula as proposed. This would appear much more congruent with Board RRFE policies which highlight the need to smooth capital expenditures over rate plan period.

Of course it is possible that Hydro One has made an error in the calculation of line 14 - *"Less Capital Related Revenue Requirement in I-X"* and that the summation of the capital factor, productivity factor and inflation are supposed to equal the proposed change in revenue requirement shown in line 11. If that is the case the argument still resonates. If that were the case the one would need to ask what the point of the formula? If one knows the capital spending, the OM&A and the actual inflation factor why not simply adjust the revenue requirement taking the proposed revenue requirement shown in line 11of Table 2 and increasing it by the rate of inflation net of 0.45%?

10. Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

In its evidence Hydro One makes the following statement:

> "The PEG model forecasts that Hydro One's test year costs are 37% greater than Hydro One's predicted costs which, based on the OEB's standard approach, would assign Hydro One to the Group 5 stretch factor ranking and result in a stretch factor of 0.6%. Hydro One does not propose to adopt this stretch factor."[9]

While the Board's July 2017 update modifies this result and puts Hydro One into Cohort 4 (and hence the above statement should adjusted to read Group 4 and a stretch factor of 0.45%) the utility remains a relatively poor performer as shown by the PEG models regarding predicted costs.

[9] Exhibit A, Tab 5, Schedule 2, pg.1

Source A-05-02-01 Excel Spreadsheet	**2015 (History)**	**2016 (History)**	**2017 (Bridge Year)**	**2018 (Test Year)**	**2019**	**2020**
Cost Benchmarking Summary						
Actual Total Cost	1,463,400,460	1,523,555,234	1,569,706,605	1,620,722,643	1,681,295,841	1,739,932,246
Predicted Total Cost	1,008,508,233	1,056,761,415	1,090,963,888	1,126,298,441	1,162,289,721	1,201,148,100
Difference	454,892,227	466,793,820	478,742,717	494,424,202	519,006,120	538,784,146
Percentage Difference (Cost Performance)	**37.2%**	**36.6%**	**36.4%**	**36.4%**	**36.9%**	**37.1%**
Three-Year Average Performance			36.7%	36.45%	36.56%	36.79%
Stretch Factor Cohort						
Annual Result	**5**	**5**	**5**	**5**	**5**	**5**

The evidence indicates that Hydro One's improvement relative to other Ontario LDCs has more to do with the sector's declining performance (largely due to increased capital programs among Ontario electricity distributors) than to any inherent improvement at Hydro One.

In their argument Board Staff have highlighted deficiencies in the PSE Total Cost Benchmarking approach. The germane issue here is the cohort Hydro One should be benchmarked against. While we agree with Staff's analysis we are less convinced that Hydro One cannot or should not be benchmarked against other Ontario Utilities. And while customer density may drive real differences in costs they do not explain the poor cost efficiency performance of Hydro One as benchmarked against its own past performance.

Based on Hydro One's historical and projected cost Benchmarking calculated on the standard PEG modelling used by other Ontario LDC (see below) it would be reasonable for the Board to modify the rate plan formula to take into account the continued poor performance of Hydro One,

11. Are the results of the studies sufficient to guide Hydro One's plans to achieve the desired outcomes to the benefit of ratepayers?

VECC has no submissions with respect to this issue.

12. Do these studies align with each other and with Hydro One's overall custom IR Plan?

Generally, VECC supports the program based productivity and benchmarking initiatives provided in this application. We agree with Board staff that it is difficult to ascertain the link between the initiatives and its actual impact on rates.

In VECC's submission the next step to be taken is better integration of initiatives with the rate plan. These should show clear and demonstrable cost efficiencies that will be made. Progress should be measurable. The Board might consider requiring the Utility to work with intervenors on this next step during the approved rate plan period.

13. Are the annual updates proposed by Hydro One appropriate?

No. There is no compelling rationale to adjust the cost of capital in the mid-term of the rate plan. The rationale provided by the Applicant is that there is a nexus between the integration of the acquired utilities and the cost of capital.

None of the arguments Hydro One makes with respect to the adjustment of cost of capital are persuasive. For example, the Applicant states:"*[M]oreover, Hydro One notes that cost of capital is intended as a forecast for a short period, not a forecast of the cost of capital for five years, and therefore Hydro One is concerned that the Board's direction relating to charging customers of the Acquired Utilities their costs to serve will not be met if Hydro One calculates its rates based on an out-of-date cost of capital value.*"[10]

We are uncertain where the Applicant came to the understanding that the cost of capital is intended to be set for short periods, whereas the OM&A, capital spending and other aspects of the cost of service are meant to be set for longer period. What we think the Applicant means is that they are more wary of the risks with respect to the trend in interest rates than they are with respect to the trends in current or capital spending.

Certainly no Board policy supports this view. Nor is there any inherent logic in the concept that the integration of the acquired utilities, which are in any event, an intestinal portion of the Utility's rate base, require a revisiting of the cost of capital.

What we do recognize, and we are sure the Applicant does also – is that the general trend in interest rates in upward. In such an environment there is an adverse risk to Hydro One that the return on debt and capital will be negatively affected over the rate plan period. Of course there are similar risks to ratepayers that the forecast load will be

[10] Hydro One Argument-in-Chief, July 20, 2018, page 35

wrong, that the operating costs will be less than forecast or that the capital requirements will be different than proposed.

In our view the Board should reject the mid-term cost of capital review. There is not reasoned basis upon which to make this one change as opposed to the multitude of other adjustments that might be made to protect the interest of consumers. If we are wrong we are certainly curious as to the reasons to adopt this shareholder serving proposition.

14. Is Hydro One's proposed integration of the Acquired Utilities in 2021 appropriate?

We have made our submissions with respect to the acquired utilities under issues with respect to cost allocation and the rate adjustment formula.

15. Is the proposed Earnings/Sharing mechanism appropriate?

VECC submits the earning sharing mechanism proposed is consistent with similar Board approved rate plans. However, we also note that the Board has adjusted ESM sharing to account for specific aspects of the utility's rate plan.

VECC has argued for the removal of the capital factor adjustment. If the Board makes these adjustments or otherwise similar adjustments to make the proposal more even handed as between ratepayer and shareholder than the proposed ESM sharing proposal may be fair share. If the Board accepts the proposed rate adjustment mechanism largely as proposed then we believe the earning sharing mechanism should be modified to remove the proposed 100 basis point dead band.

As discussed above in our view the current proposal allows the Applicant to calculate rates largely on a cost of service basis. Under such a rate regime Hydro One is able to substantially reduce its revenue requirement recovery risk. As such windfall revenues or unanticipated efficiencies should accrue to ratepayers not the shareholder.

16. Are the proposed Z-factors and Off-Ramps appropriate?

In VECC's submission Hydro One's proposed threshold level of $1 million is too low. This is far lower than the threshold levels approved for similar sized utilities. It is also disproportionately small in relationship to its average revenue a requirement of $1.5 - $1.6 billion or its annual capital programs which average around $1 billion.

Hydro One relies on Chapter 3 of the Filing Requirements for the proposed threshold. In our submission the Filing Requirements provide the minimum requirements for electricity distribution utilities ranging in size from a few thousand customers to over a million. In any event they are "filing requirements" not decisions of the Board. Hydro One should have no expectation of approval by simply meeting a filing requirement. To say otherwise would be to suggest that by meeting the filing requirements one has established all that is need to set rates as just and reasonable. This is clearly not the case.

The Board must exercise its discretion to determine what is just and reasonable. In this case the Z-factor filing requirement is clearly unreasonable for a utility the size of Hydro One.

A reasonable Z-factor materiality threshold of $3.75 million would represent 0.25% of either the average revenue requirement or annual capital budget. In our view this is a reasonable figure and more in line with that approved for similar large Ontario utilities.

C. OUTCOMES, SCORECARD AND INCENTIVES

17. Does the application adequately incorporate and reflect the four outcomes identified in the Rate Handbook: customer focus, operational effectiveness, public policy responsiveness, and financial performance?

VECC has no submissions under this issue.

18. Are the metrics in the proposed additional scorecard measures appropriate and do they adequately reflect appropriate outcomes?

VECC is generally supportive of the scorecards proposed by Hydro One. In our submission the Board should require Hydro One to report on the comprehensive Scorecard provided by Hydro One in response to SEC interrogatory 29[11].

Hydro One has made significant strides in refining its metrics since the last cost of service application. The Board should encourage future improvements. Among these is the integration of the various scorecards and metrics used by the Utility.

In addition to the proposed and OEB scorecard Hydro One uses a Corporate Scorecard[12] and Team Scorecards[13]. Integration of the corporate and regulatory scorecards, or at least a mapping of their interrelationship would benefit all interested parties in future proceedings.

As noted above Hydro One should also consider how to include specific service reliability metrics for First Nation Communities.

Finally, there is no direct linkage between scorecards and the rates paid by consumers. Ideally scorecard performance should inform the rate plan. For example, capital programs that fail to achieve, or exceed expected reliability performance indicators should factor into rates in a subsequent period. In our view the next step for Hydro One should be to consider ways to make scorecard outcomes meaningful in terms of the rates customers pay.

19. Are the proposals for performance monitoring and reporting adequate and do the outcomes adequately reflect customer expectations?

VECC's submission with respect to this issue are made under issue #18.

[11] Exhibit I, Tab 18, Schedule SEC-29
[12] See for example Exhibit I-3-SEC-2
[13] TC Vol.1., June 11, 2018, pages 100-106

20. Does the application promote and incent appropriate outcomes for existing and future customers including factors such as cost control, system reliability, service quality, and bill impacts?

VECC's submissions with respect to this issue are made under issue #18.

21. Does the application adequately account for productivity gains in its forecasts and adequately include expectations for gains relative to external benchmarks?

Hydro One provided a detailed productivity savings updated in response to Board Staff interrogatory #123.[14] There is nothing inherently wrong or reason to disapprove of any of the detailed productivity programs outlined in the evidence. However as noted by the Board in Hydro One's prior cost of service application "*The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.*[15]"

While the productivity programs outlined in the evidence are helpful in understanding how Hydro One intends to reduce its costs during the rate period they provide no additional efficiencies to ratepayers since they are already embedded in the rate plan.

We are not critical of the proposals we just do not think that one can take the ongoing expectations of management – that they develop programs to improve results for shareholders and customers – as an incremental benefit that should somehow be factored into to how rates are set. Simply put, management is compensated to find ways to make companies more efficient. That they do are doing so is laudable and certainly better than the alternative. However, such efforts are not worthy of extraordinary compensation from ratepayers - they are simply part of doing business.

22. Has the applicant adequately demonstrated its ability and commitment to manage within the revenue requirement proposed over the course of the custom incentive rate plan term?

VECC has no specific submission with respect to this issue.

[14] Exhibit I, Tab 25, Schedule Staff-23 /original at Exhibit B1-1-1, DSP Section 1.5, page 2
[15] Reason for Decision EB-2013-0416/EB-2014-0247, page 14

D. DISTRIBUTION SYSTEM PLAN

23. Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Maintaining Reliability

Hydro One's Board chose Plan B modified on the basis of information that it was the minimum level of expenditures necessary to maintain reliability which they believed to reflect the preferences of consumers. However, subsequent to that assessment being presented to the board, Hydro One looked at various programs and identified opportunities for improvement, which are expected to result in a 27% improvement in reliability:

> MR. SEGEL-BROWN: [...]
> Just to clarify one point before I start, from your testimony earlier, Hydro One is forecasting a 20 per cent reduction in SAIDI due to defective equipment under the current Plan B modified?
> MR. JESUS: That's correct. As part of the worst performing feeders, the grid modernization, and the system renewal, they will all contribute to a 20 percent reduction in SAIDI, and we're attributing that to the red, to the contribution from defective equipment. That's where it's being shown.
>
> MR. SEGEL-BROWN: I put it to you that that is inconsistent with the table comparing the plans that was put to the board of directors, and I'm not going to put you on the spot to explain that, but if you want to take an undertaking to try and reconcile that -- no?
>
> MR. JESUS: It is not consistent with the material that went to the board of directors, because we've subsequently looked at the various programs, including the worst-performing feeders, the grid mod (sic), the vegetation management, as well as our process improvements associated with the operating centre, so we subsequently reviewed what we can do, and that's where those materials are coming from, and we've identified right from the get-go in the response to the interrogatories that the performance improvement is going to improve by approximately 27 per 10 cent over the next five years overall.[16]

Hydro One's customer engagement feedback suggest that residential consumers are not interested in paying more to more for more reliable service.

Ipsos's question number 17 regarding whether consumers are willing to pay 1.1% (i.e. 2$) more per month more each of the five years to maintain reliability must be

[16] Hearing Transcript, Volume 8, page 94.
<http://www.rds.oeb.ca/HPECMWebDrawer/Record/612427/File/document>.

disregarded.[17] First, consumers were given no counterfactual – they were not told what would happen if their bill was not increased:

> MR. SEGEL-BROWN: So I reviewed what the informed customers were informed about, so they were informed about Hydro One, its service territory, its performance in terms of the average number and length of power outages, and why outages occur; is that what these customers were informed about, relative to the uninformed segment?
>
> MS. GUIRY: Relative to the uninformed segment, yes, and so the information that you just referenced is we --included in the appendix the actual questionnaire so you can see the information that was provided to informed customers.
>
> MR. SEGEL-BROWN: So I reviewed those materials, and those materials do not indicate what the reliability impact would be if the $2 -- if the investment that you are discussing in this question is not made; is that correct?
> MR. GRIFFIN: That's correct.[18]

Would there be a 0.5% decrease in reliability or a 50% decrease in reliability? Because the consequences of not paying to maintain reliability are not specified, the question does not really provide any information about whether consumers are willing to accept the reliability impact associated with lower costs. Second, the methodologist confirmed that the question would have been interpreted as a nominal 1.1%/2$ increase, not an increase in real terms:

> MR. SEGEL-BROWN: Okay. And it's also not clear from this question whether this is a real or a nominal change, whether the 1.1 percent increase you are talking about would be an increase in the nominal amount or an increase in the real amount; is that correct? What do you think a consumer would -- what impression would a consumer get from your question?
> [Witness panel confers]
>
> MR. MERALI: Can you clarify when you say "nominal and real", are you -- like, with respect to inflation or –
>
> MR. SEGEL-BROWN: So with respect to inflation, is the consumer expecting their bill to go up 1.1 percent literally? It is 100 this year, it's 101 next year? Or are they expecting it to go up 1 percent in real terms so it will be up, you know, 3 percent next year?
>
> MR. MERALI: I don't believe inflation was cited. I mean, we can take a quick look, but I believe it was in the first example you stated --
>
> MR. SEGEL-BROWN: In nominal terms?
>
> MR. MERALI: Yes.[19]

---

[17] HONI Update Exhibit B Part 2_2, DSP-1-3-A01 at 1471 (17 of report)

[18] Hearing Transcript, Volume 5, page 4.

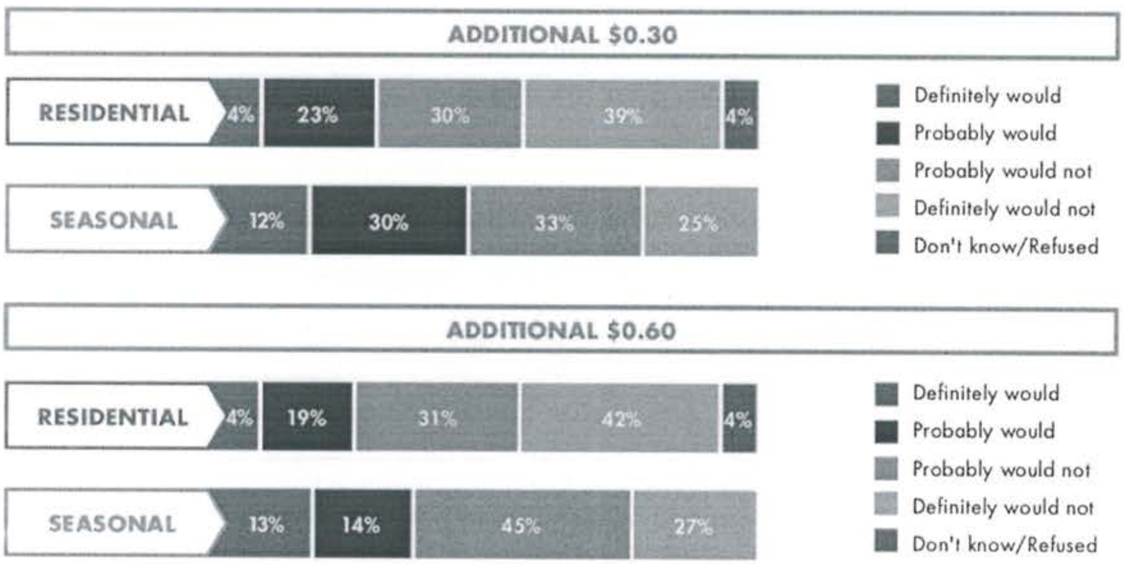
So the amount consumers expressed willingness to pay to maintain reliability is less than inflation, never mind the substantial increases Hydro One is proposing. In fact, the plurality of residential respondents suggested that Hydro One should allow the average length of power outages to increase in order to keep costs low:

> MR. SEGEL-BROWN: Yes, so looking at the top orange box that's shown on the screen there:
>
> > "33 percent of customers said that Hydro One should allow the average length of power outages to increase in order to keep the costs low."
>
> And that's the plurality of respondents?
>
> MS. GUIRY: That's correct.[20]

When consumers were asked to trade-off a specific reliability impact against a specific price change, most consumers were willing to pay less than $0.30/month increase per year for a 10% increase in reliability:

ONLINE WORKBOOK: REPRESENTATIVE SAMPLE

WILLINGNESS TO PAY FOR IMPROVED LEVELS



Q20A Would you be willing to pay an additional [HALF OF RESPONDENTS SHOW $0.30/OTHER HALF SHOW $0.60] per month over and above the $2.00 which would be approximately [SPLIT SAMPLE $2.30/$2.60 more per month if it meant that Hydro One could reduce the number and length of future power outages by 10%? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$11.50/$13.00] higher than it is now? Base: Residential/ Seasonal customer; Residential (split n=756/n=746), Seasonal (split n=50/n=52)

---

[19] Hearing Transcript, Volume 5, page 5.

[20] Hearing Transcript, Volume 5, page 5.

> MR. SEGEL-BROWN: So those results indicate that only 20 percent of consumers, if we are counting the definitely would and probably would, would be willing to pay 30 cents a month more for a 10 percent increase in reliability?
>
> MS. GUIRY: I believe you are referencing residential customers; 6 percent definitely would, 18 percent probably would.
>
> MR. SEGEL-BROWN: Yes.
>
> MS. GUIRY: Correct. [21]

VECC submits that, consistent with Hydro One's customer engagement feedback, consumers are willing to pay very little, <$0.30/month increase/year, for even a substantial 10% improvement in reliability. As a result, the OEB should use make cuts to the reliability investments in Hydro One's budget to seize this opportunity to lower rates while maintaining reliability. Hydro's One's capital plan overinvests relative to what consumers are willing to pay for reliability. Because Hydro One has found other opportunities to improve its reliability which create substantial room to reduce capital spending while maintaining reliability, it is appropriate to focus on what consumers are willing to pay for improvements in reliability. Willingness to pay for improvements in reliability is also likely the best proxy for consumers' willingness to accept for decreases in reliability.

We have made a number of similar points about customer consultation under issue 2. These are specific to the issue of how customer consultation might influence the Utility's distribution system plan.

Hydro One has undertaken customer consultation similar to that seen by VECC in a multitude of cost of service applications over the past few years. As with the vast majority of those the exercise undertaken is largely meaningless. This is not for a lack of trying or we hasten to add, particularly the fault of Hydro One. Such exercises are inherently flawed and for two reasons.

The first is that customers are inevitably interested in two things – the price they pay for electricity service and the reliability of that service. If prompted consumers will generally add safety to their list of priorities. This is borne out time and time again in the numerous surveys done by utilities and other third parties hired by utilities. In our view it is not necessary to continually poll consumers to understand their priorities.

Second is the false choice made with respect to capital programs in these surveys. Inevitably such exercises imply, or sometime simply state, a false sense of how direct

[21] Hearing Transcript, Volume 5, page 6.

the connection is between capital spending and reliability. In fact there is not such lucid connection. By their own admission utilities, including Hydro One, when challenged are quick to point out that there is a high level of uncertainty between what is spent and what is achieved in the sense of reliability outcomes. Were it not so the Board (or the Applicant) would be able to devise rate setting schemes which would provide incentives and penalties based on reliability outcomes of the capital spending programs proposed.

The customer engagement with respect to capital planning in this proceeding is much like any other we have reviewed. There is an implied link made between capital spending and reliability. The Utility projects a certain level of capital spending below which it suggests degradation of service will occur. In reality the tipping point is unknown.

As we argue below, there is no compelling evidence that a modest reduction in the system renewal capital budget would have an impact on reliability in the short or long-term. The evidence being that the Utility has managed with much lower spending in all years before and maintain a stable history of outages.

In our submission the customer engagement is indeterminate of customers' views on the adequacy of the Applicant's capital program. The Board should put no weight on this evidence.

Rather VECC has consistently argued for improvements in data collection on outages, the refinement of cause codes and other studies to build a better understanding between capital spending and its reliability outcomes. In our submission the Board should continue its initiatives to understand the relationship between investment and outcomes.

24. Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Hydro One developed a detailed a capital planning exercise as part of this rate proposal. And while we are sceptical of its accuracy with respect to reliability outcomes, we applaud Hydro One for its efforts to draw closer that relationship. It is, in our view Hydro One is a leader in this endeavour.

VECC is generally supportive of the capital planning exercise of Hydro One. Where we disagree is on the level of specificity implied in the analysis of capital expenditure and outcomes.

25. Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

VECC has no submissions under this issue.

26. Does the Distribution System Plan address the trade-offs between capital and OM&A spending over the course of the plan period?

In our submission Hydro One did not provide any detailed evidence upon which to draw a reasoned conclusion to this question. The Applicant has noted that it uses analytical tools to help make a determination between "replace or repair" decisions. The Utility also notes in their argument that the choice between capital and maintenance expenditures is often binary.[22]

In our view the Applicant could do more to explore and discuss the trade-offs between asset maintenance and replacement. Intuitively there should be a close (and inverse) relationship between the pattern of asset replacement and the pattern of asset maintenance. In this Application Hydro One proposes a significant increase in asset replacement yet there is little to none discussion on how this might affect maintenance costs.

27. Has the distribution System Plan adequately addressed government mandated obligations over the planning period?

VECC has no submissions under this issue.

28. Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?

VECC submits Hydro One has met its obligations to incorporate regional planning in its capital programs.

[22] Argument-in-Chief, July 20, 2018, page 83-84

29. Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

The capital plans of a utility have the sole purpose of ensuring the safe and reliable distribution of power to customers. Safety is an issue addressed by the ESA through the standards and practices it requires distributors to meet. As such its costs are embedded in all costs of the Utility. Reliability is the bailiwick of the utility under the auspices of Ontario Energy Board.

The table below shows the causes of power outages by general category of causes[23].

Power Outage Causes	2013	2014	2015	2016	2017
Tree damage	18%	18%	19%	24%	25%
Equipment failure	25%	27%	29%	25%	32%
Unconfirmed causes	25%	23%	22%	21%	17%
Scheduled outages	25%	23%	22%	22%	16%
Animal or vehicle damage	7%	9%	8%	8%	10%

*Excludes Force Majeure and Loss of Supply events

Tree damage is largely weather driven and addressed by OM&A vegetation programs[24]. The other categories are addressed largely by capital spending. Of these outages due to unconfirmed, scheduled and accident or animal contacts are reasonably stable over the 2013 to 2017 period. Being random in nature these types of incidents are relatively impervious to capital programs.

Capital programs largely only impact equipment failure, unconfirmed (unidentified) caused outages and scheduled outages. While there is some modest movement around the category of equipment failures, for the other two categories the pattern of outages has been relatively consistent.

We have tried to match equipment failure outages to the sustainment capital in-service additions. Assuming a one year lag between the investment and its impact on equipment failure we can find no discernible pattern. For example, the highest year spending on sustainment was in 2015. That year was followed by a modest drop in equipment failures. On the other hand the second highest year spending on sustainment projects was in 2016 which was followed a year later by the highest year ever in outages attributable to equipment failure.

[23] Undertaking JT 3.1-3

[24] See for example, Exhibit I, Tab 29, Schedule VECC-27

Table 1: In-Service Capital Additions 2013-2017 ($M)
OEB Approved and Actual/Forecast (updated for 2017 Actuals)

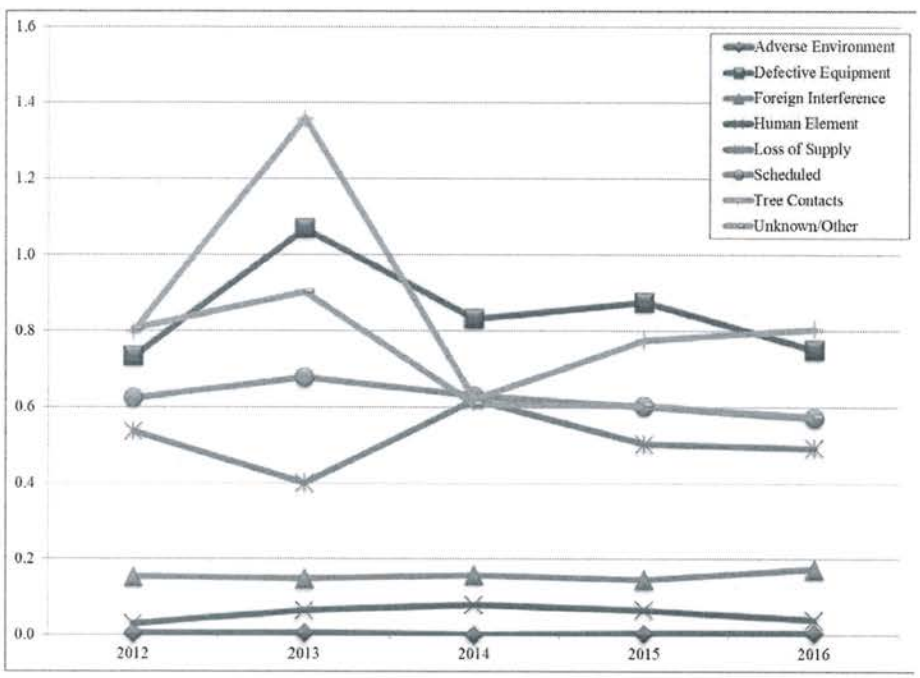
	Historic								Bridge		
	2013	2014	2015			2016			2017		
	Actual		OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance (Act)
Sustaining	296.6	324.8	294.2	420.2	126.0	311.9	371.1	59.2	335.7	322.8	-13.0
Development	194.1	187.6	218.9	216.9	-2.0	200.8	168.3	-32.5	211.2	216.5	5.3
Operations	1.4	5.0	11.1	7.0	-4.1	8.1	-0.3	-8.4	16.4	14.0	-2.4
Customer Service	13.9	1.4	46.0	16.6	-29.4	20.6	6.5	-14.1	27.7	10.9	-16.7
Common & Other	223.4	96.6	86.5	100.5	14.1	80.4	109.3	28.9	105.0	116.8	11.8
Total	729.3	615.3	656.7	761.3	104.6	621.8	654.9	33.2	696.0	681.0	-15.0

Source Exhibit I, Tab 33, Schedule AMPCO-52

Of course, this is not a scientific or detailed analysis of the relationship between sustainment spending and its impact on reliability. It might be that the lag between investment and outcome is longer, or it could be that the level of detail with respect to outages conflates different root causes of equipment failure. Nevertheless it shows that the relationship between spending and reliability outcome is not precise.

In any event Overall Hydro One has had a declining trend of outage frequencies.[25]

Figure 7 - Chart of SAIFI by Outage Cause



[25] Exhibit B1-1-1, DSP Section 1.4, page 26

Hydro One is proposing to ramp up its system renewal spending considerably from the patter of spending between 2013 and 2018. The question is whether this is warranted. We would argue that based on the evidence of past reliability and capital spending it is not.

In its essence Hydro One's argument is that large portion of its capital stock, primarily poles, is reaching a critical end-of life. That some of this capital stock is old is not at dispute. That it is reaching end-of-life is.

The system renewal program which is the source of the large increase in capital spending is largely driven by a pole replacement program. The difficulty is that depreciation life for poles and actual pole life do not appear to be well matched. In VECC's experience this is not unusual. Distribution poles are subject to an extraordinarily wide variety of environmental conditions, have been installed in a wide variety of environments and with a variety of pole material used. Furthermore pole failure largely occurs due to tree contact, ground contact rot, or human intervention (accidents). This means that the actual life of poles has a much wider variation than can demonstrated by age and even sample testing.

Furthermore as noted in this proceeding little study has been done on the issue of pole refurbishment. Finally there is no clear relationship, or evidence in this proceeding, between pole failure and power outages. This doesn't mean that poles don't have to be replaced when failure occurs but it does imply that reactively replacing poles may be as effective as proactive replacement in terms of reliability outcomes. In fact, it appears to reactive replacement has largely been the modus operandi in prior years.

The capital planning process employed by HONI tries to address the question of reliability outcomes under different capital spending scenarios. The difficulty as we have pointed out is that there is no robust science or modelling upon which to derive a relationship between the two. If there were it would be possible to test the results. When asked about the possibility of deriving a relationship between capital investment and outage outcomes Hydro One responded:[26]

> Hydro One has not attempted to regress capital investment spending against lagged outages because there are many factors (e.g. weather, environment, geography, length of supply, voltage level, age and condition of assets, customer density, tree density, species etc.) that impact the historical outage performance and the capital expenditures required to sustain, develop and manage an aging distribution system consistent with customer and regulatory requirements

[26] Exhibit I, Tab 29, Schedule VECC-27

VECC agrees that the exercise would be difficult though not impossible as implied in the response. We also agree with Hydro One that there is no "one-to-one" causal relationship between investment and reliability outcome.

Hence our conclusion that there is always uncertainty within any capital plan and room to adjust capital budgets so as to minimize rate impacts without any inordinate increase to reliability

Monopoly utilities are naturally reliability risk adverse since the risk of customers or revenue loss is small, but the risk of backlash (political or regulatory) is high.

Hydro One is proposing to increase its five year annual average capital spending by over 10% per year. System renewal spending would increase by an average of 28% per year. In our view the evidence with respect to system reliability and the impact of the proposed capital spending does not warrant such a large increase.

In our submission Hydro One's system renewal budget should be limited to a 15% increase over the next five years. This would provide ample new spending for projects to address system reliability and Hydro One's aging asset base. Such a reduction would amount to an average system renewal spending of $310M in each year of the rate plan.

Should the Board determine that a higher amount of system renewal spending is warranted we would point out that Hydro One has made this commitment:[27]

> Hydro One has scorecard metrics related to reliability. Our goal is to achieve a 20% improvement in reducing defective equipment outages over five year period through system renewal investments, distribution automation and worst performing feeder improvements documented in Exhibit B1, Tab 1, Schedule 1 and Exhibit I-23-Staff-85, part a).

We believe Hydro One should be held to this commitment. If at the end of the rate plan period the five year average defective equipment outages have not been reduced by 20% as compared to prior five year average then the Board should be prepared to make the necessary adjustment in the post 2022 rates to reflect any failed outcome.

<u>Wood Pole Replacement (SR-09)</u>

Hydro One proposes to spend $579 million over five years to replace 72,151 poles in poor condition under its pole replacement program.[28] This program addresses only the replacement of poles which have failed inspections. Poles are replaced for other

[27] Exhibit I, Tab 18, Schedule VECC-18

[28] Exhibit B1-1-1, DSP Section 3.7, Page 1.

reasons under other programs, such as the Distribution Lines Trouble Call and Storm Damage Response Program (SR-07).

Refurbishment

Navigant's Distribution Unit Cost Benchmarking Study suggests that there are cost effective opportunities to refurbish wood poles, notes most other utilities have refurbishment programs and recommends that Hydro One establish a refurbishment program.[29] In cross examination, Hydro One conceded that 10,000 of their poles scheduled for replacement are likely to be suitable for refurbishment:

> MR. SEGEL-BROWN: What portion of the poor-quality poles scheduled to be replaced in this application are suitable for refurbishment?
>
> [Witness panel confers]
>
> MS. GARZOUZI: From the 106,000 poles that we discussed, we think that there's a 10,000 population that would be candidates, but through conversations with vendors and as we familiarize ourselves more with the refurbishment methods, we will refine our assumptions. I can tell you that we are prioritizing for replacements the ones that are less suitable for refurbishment.
>
> MR. SEGEL-BROWN: How did you determine that 10 per cent -- that 10,000-pole figure?
>
> MS. GARZOUZI: We removed the red pine population from the 106,000. We removed the poles that had woodpecker damage, removed the ones that were off-road, and the reason we removed those is because of climbing access and so on. We removed incompatible soil, and the reason for that, we mean in rock or in swamp. That was from a mechanical perspective and also a chemical perspective. And we removed the poles that were 50 years or older, based on Mr. Buckstaff's comments. We also removed the ones with the joint-use attachments, and the reason for that is we cannot alter strain on poles that have been mechanically braced. And that's how we got to 10,000.[30]

The cost of replacing a pole is substantially higher than the cost to refurbish a pole, with replacement being approximately 7x more expensive where refurbishment is an option.[31] With 72,151 poles scheduled to be replaced, 10,000 poles represents 13.8% of the poles planned for replacement, with an associated cost of $80.2 million. Deducting the $11 million cost of refurbishing those poles (a seventh of the replacement costs) suggests that refurbishment will reduce wood pole replacement expenditures by $69 million. This figure can be deducted from the planned pole replacement budget. If refurbished poles have a shorter life than new poles, the long-term savings from

[29] Exhibit B1-1-1, DSP Section 1.6, Attachment A01, Page 13,16.

[30] Hearing Transcript, Volume 8, page 28-29.
<http://www.rds.oeb.ca/HPECMWebDrawer/Record/612427/File/document>.

[31] Exhibit B1-1-1, DSP Section 1.6, Attachment A01, Page 16.

refurbishment will be less than 6/7 of the replacement cost while still representing a cost reduction, but such future needs arising from pursuing refurbishment rather than replacement would fall beyond 2022.

VECC submits that the number of poles suitable for refurbishment is actually substantially higher. The 10,000 pole figure is based on the analysis by Navigant – Hydro One excluded "poles that were 50 years or older, based on Mr. Buckstaff's comments" to the effect that refurbishment only makes economic sense when the pole has a remaining planned life of 20 years.[32] However, the planned life of wood poles is an artificial construct reflecting the number of poles divided by the number of poles replaced each year. The real question is whether refurbishment is likely to make a wood pole last an average of 20 years longer. Furthermore, replacing rather than refurbishing a pole will not avert having to replace that pole for reasons other than failing an inspection – no pole will survive being hit by a truck – so the question is whether refurbishment is likely to extend the time until a pole re-fails inspection by 20 years.

Using the full dataset from 2005-2013, HONI's data suggests an average pole life of between 99and 144 years depending on the model used, meaning that HONI is on track to have only half of its poles fail inspections by 99 to 144 years.[33] For an older pole, the remaining life is shorter, but some of the risk of early failure has already passed. As an extreme hypothetical, a 150 year old pole would have an expected total life of longer than 99 to 144 years because the risk of failure prior to 150 years has already passed. Assuming a 200 year natural life and flat inspection failure rates, a 150 year old pole would have a 175 year expected life and be eligible for refurbishment, even though its initial expected life was just 100 years.

Schedule B2

HYDRO ONE NETWORKS INC.
Distribution Lines
Account: DXPOLES1 Poles - Inspection Failures

T-Cut: None
Placement Band: 1929-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2005-2013	55.1	106.7	L0.5	2.83	99.1	S0	2.39	144.6	SC *	3.34

[32] Hearing Transcript, Volume 8, page 28-29.
<http://www.rds.oeb.ca/HPECMWebDrawer/Record/612427/File/document>.
[33] EB-2016-0160, Hydro One Networks Inc.'s 2017 and 2018 Transmission Cost-of-Service Application – Disclosure of previously filed Confidential Materials, Fosters Associates 2014 Failure Analysis Report, Page 14.

Figure: From Foster Depreciation Study, Schedule B2, as referenced in H1 Interrogatory and distributed to interveners by Ms. Grice

The point of the above explanation is that **none** of Hydro One's poles should have been excluded from potential refurbishment on the basis that their remaining planned life is less than 20 years. First, the average life at installation of Hydro One's poles is expected to be 99 to 144 years, which leaves 20 years of life for almost all Hydro One's poles even with the lower figure. Second, the expected life of an older pole must be reassessed in light of the fact that the risk of early failure has already passed.

The "expected service life" of poles is confusingly defined as the average age of poles which have failed. It does not reflect the what the average life of poles is expected to be because it only considers those poles which have failed and not the portion surviving. To illustrate, if a utility installed a million poles, and 50 years later 10% had failed, the "expected service life" would be less than 50 years (the average age of the poles already failed) even though 90% of poles would have lasted longer than 50 years.

This average life analysis also fails to take into account any improvements in the quality of poles or quality of pole installations over the last 80 years:

> MR. SEGEL-BROWN: So the quality of the poles at time of installation, has that improved over the last 80 years? Are you installing better poles now than you were 80 years 16 ago?
>
> MS. GARZOUZI: I don't know the answer to that.
>
> MR. SEGEL-BROWN: Similarly, would you know if the quality of your installations has improved over the last 80 years? What I'm getting at is would we expect the poles which are installed more recently to last longer than those which are failing now.
>
> MS. BRADLEY: I think the only time I could comment on that is you could buy composite poles today, composite poles today that are more resistant to things like woodpecker damage. They are significantly more expensive. But to take a wood pole that was built 80 years ago, I don't have a perfectly preserved one from 80 years ago to compare to ones we would buy today. I'm not sure we could speculate on that.[34]

Hydro One's analysis is based on the failure of poles installed many decades ago and does not account for any improvements in the quality of poles or pole installations. By not distinguishing between older and newer pole installations, it is assuming that more recently installed poles will only last as long as the oldest poles. As a result, the life of more recently installed wood poles may be significantly underestimated, which would further contribute to an underestimation of the portion of wood poles suitable for refurbishment.

---

[34] Hearing Transcript, Volume 8, page 126.
<http://www.rds.oeb.ca/HPECMWebDrawer/Record/612427/File/document>.

Need

Hydro One's pole replacement program is solely intended to replace poles which have failed inspections. Old poles do not necessarily need to be replaced – only poles which have failed an inspection are replaced.[35]

> MS. GARZOUZI: If they fail the testing criteria, we categorize them at end of life, and those are the only poles we he would replace. Hence, if you are old and you're in good shape, we leave you in the system and that's the way we like it. We want to extend the life of our poles as much as possible

An aging pole population, or older average age of poles, is not a problem.

Confusingly, Hydro One testified that poles which have failed inspections are not actually more likely to fail because they are replaced before they fail. This is problematic, because it means that Hydro One's pole inspections are not being tested against real-world data. Hydro One is not assessing whether all the poles assessed to be in poor condition are actually at an elevated risk of failure, nor it is assessing those poles which fail in storms to determine whether those poles have characteristics which could have being used to predict the failure of those poles.

VECC notes that asset analytics were a significant shortfall in Hydro One's management of its capital programs as identified by the Auditor General of Canada.

Before granting the full proposed expenditure, the Board should seek evidence that the full scope of the proposed pole replacement program is necessary, i.e. that pole assessments are accurately predicting a current or near future increase in failure risk. VECC suggest that 20% of the proposed capital expenditures for 2019-2022 should be withheld until Hydro One can demonstrate, though rigorous analysis, that all classes of poles which have failed inspection and are scheduled for replacement have (or will have) a substantially elevated risk of failure.

The decision is not between replacing poles on a reactive basis and replacing poles at increased rates. Different classes of poles will have different probabilities of failing. Consumers are willing to pay very little for improved reliability. If the baseline probability of a pole failing in a given year is 2%, is it worth replacing a pole whose probability of failing is 3%, or 4%? Are the impacts of a pole failing due to woodpecker damage different to those failing due to those failing due to below-ground rot? Are the safety risks different between urban areas as opposed to transmission lines between communities? Hydro One's application does not provide the data needed to determine

[35] Hearing Transcript, Volume 8, page 28-29.
<http://www.rds.oeb.ca/HPECMWebDrawer/Record/612427/File/document>.

the risk mitigated by different types of pole replacements. With half a billion in planned expenditures, a better understanding of the risk mitigated by those expenditures is needed. The Board does not have the information it needs to determine whether the risk associated with some poles which have failed inspections is tolerable in light of consumers' limited willingness to pay for reliability improvements.

Hydro One has also not analyzed the implications for its pole replacement program of its improved vegetation management cycle. This work program may reduce the burden on lines, lowering the risk of pole failure and therefore reducing the need to maintain as high a portion of original pole strength.

Cost effectiveness

In the Ontario Energy Board's (OEB's) decision in EB-2013-0416/EB-2014-0247 on Hydro One's distribution rates for 2015 to 2019, the Board directed Hydro One to "to conduct an external benchmarking study on the unit cost of its pole replacement and station refurbishment programs against other utilities as well as carry out an internal trend analysis to show the variability of these unit costs over time (year over year)". That study shows that Hydro One's mean cost to replace a pole was "$8,266, or 16% higher than the mean" of $7,105.[36]

Unit costs are calculated on a slightly different basis for benchmarking than is given by diving capital expenditures by the number of poles replaced. Using the later method, Hydro One's pole replacements averaged $7,410/pole. Hydro One's proposed unit costs for pole replacements come out to $7,688/pole in 2018, rising to 8,025/pole in 2019. VECC submits that the OEB should rely on the typical costs established by the benchmarking study in lieu of Hydro One specific costs to give Hydro One a greater incentive to improve its relative cost efficiency.

VECC is concerned about the lack of accountability for meeting pole replacement targets. It seems like the less Hydro One achieves, the greater its funding needs, and the greater funding it will receive on the next rebasing. To create incentives for Hydro One to reduce its relative pole replacement costs, VECC proposes that Hydro One's capital funding for pole replacements should be based on its 2015-2017 average costs ($7,410/pole), reduced by 16% to remove the 16% excess costs found by the benchmarking study (resulting in $6,388/pole), increasing with inflation over the customer IR term. Holding Hydro One to the benchmark cost per pole creates incentives for Hydro One to find cost efficiencies and relieves consumers from bearing the costs of Hydro One's relative inefficiency in pole replacements.

[36] Exhibit B1-1-1, DSP Section 1.6, Attachment A01, Page 14.

30. Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

VECC's submissions for this issue are made under Issue #29.

31. Are the methodologies used to allocate Common Corporate capital expenditures to the distribution business appropriate?

VECC has no submissions under this issue.

32. Are the methodologies used to determine the distribution Overhead Capitalization Rate for 2018 and onward appropriate?

VECC has made its submissions on this issue under Issue #39.

E. RATE BASE & COST OF CAPITAL

33. Are the amounts proposed for the rate base from 2018 to 2022 appropriate?

VECC's submissions under this issue are made under issue 29.

34. Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?

VECC has no submission with respect to this issue.

35. Is the proposed capital structure appropriate?

VECC has no submission with respect to this issue.

36. Are the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rate implementation appropriate?

VECC's submissions for this issue are made under issue 13.

37. Is the forecast of long term debt for 2018 and further years appropriate?

VECC's submissions for this issue are made under issue 13.

F. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

38. Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

VECC's submissions on this issue are made under issue 39

39. Do the proposed OM&A expenditures include the consideration of factors such as system reliability, service quality, asset condition, cost benchmarking, bill impact and customer preferences?

VECC is not seeking any adjustment in Hydro One's 2018 OM&A test year figure[37].

Table 1: Summary of Recoverable OM&A Expenses ($ Millions)

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Sustainment	325.7	304.6	316.5	323.7	361.4	304.7	367.1	346.7
Development	11.0	10.9	15.4	11.9	17.8	8.8	17.0	11.0
Operations	29.5	27.6	35.8	31.5	39.4	31.9	37.5	36.7
Customer Care	209.3	155.4	111.7	118.8	110.9	123.4	111.6	128.7*
Common Corporate Costs and Other	94.4	69.1	59.0	72.0	54.8	84.9	54.7	48.7 **
Property Taxes & Rights Payments	4.6	4.8	4.7	4.6	4.9	5.0	5.0	4.9
Total	**674.5**	**572.5**	**543.1**	**562.6**	**589.1**	**558.7**	**593.0**	**576.7**
% Change (year-over-year)		*-15.1%*	*-19.5%*	*-1.7%*	*8.5%*	*-0.7%*	*0.7%*	*3.2%*
% Change (Test vs. 2016 Actual)						*-0.7%*		*2.5%*

* Reflects reduction of bad debt based on the Fair Hydro Plan.

** Reflects reduction of transformation costs and OPEB OM&A as described in Exhibit Q.

[37] Exhibit I, Tab 38, Schedule SEC-70 Updated 2018-06-11

On the face of it Hydro One has a relatively stable, if not declining OM&A trend. However looks are deceiving. The difficulty is that under the USGAAP accounting policies adopted by Hydro One an inordinate amount of labour costs are capitalized. In fact as noted by Staff in their argument Hydro One aggressively applies than either Union Gas or Enbridge Gas Distribution.[38]

As shown the table below Hydro One habitually allocates around 50% of all compensation costs to capital[39]. This is far higher than all other electricity distribution utilities in the province.

Table 2: Corrected Allocation of Dx Compensation to OM&A and Capital

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Capital Dx Comp	169,193,807	330,855,675	321,004,661	299,243,081	342,404,569	347,815,408	333,225,316	324,634,686	327,669,257
Total OM&A Dx Comp	459,493,279	294,441,835	317,999,965	307,505,404	295,373,937	294,715,310	298,050,034	291,614,056	294,339,962
Total Dx Compensation	**628,687,087**	**625,297,510**	**639,004,626**	**606,748,484**	**637,778,506**	**642,530,718**	**631,275,350**	**616,248,742**	**622,009,219**

This means that Hydro One's increase in "OM&A type" of costs – i.e. compensation – can be masked by engaging in large capital programs.

VECC is generally sceptical of compensation studies like that undertaken by Mercer for Hydro One. Notwithstanding efforts to the contrary such studies have an inherent bias in that they are reflective of identical or related industries. In our view the relationship growth of annual wages in the province and that of Utility employees if far more meaningful since moves away from comparing Hydro One to other like monopoly companies (or governments) with a largely unionized work force. Such companies represent a minority of wage earners and comparison are self-reinforcing. It is certainly clear to us that employees of companies with a monopoly and given regulatory protection are paid significantly higher than the broader swath of wage earners working in competitive sectors of the economy. It is just not clear to us why ratepayers primarily employed in these other less fortunate sectors should be required to foot this bill.

At a minimum the average compensation level of Hydro One employees should not be allowed to exceed the average growth in wages in the economy as a whole. Otherwise the Board is allowing the relative position vis-à-vis the average employment wage to spread.

Notwithstanding our concerns the Applicant's own commissioned study showed that "*[O]n an overall weighted average basis, for the jobs Mercer reviewed in 2017, Hydro One is positioned approximately 12% above the market 50th percentile ("P50" or*

[38] Board Staff Argument, page 165
[39] JT 1.19

"median")". Meaning not only do Hydro One employees get paid well compared to the vast majority of earners in the province – they are the better paid of the best paid.

40. Are the proposed 2018 human resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate?

VECC's submissions on this issue are made under issue #39.

41. Has Hydro One demonstrated improvements in presenting its compensation costs and showing efficiency and value for dollar associated with its compensation costs?

VECC's submissions on this issue are made under issue #39.

42. Is the updated executive compensation information filed by Hydro One in the distribution proceeding on December 21, 2017 consistent with the OEB's findings on executive compensation in the EB-2016-0160 Transmission Decision?

VECC's submissions on this issue are made under issue #39.

43. Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the distribution business for 2018 and further years appropriate?

VECC's submissions on this issue are made under issue #39.

G. REVENUE REQUIREMENT

44. Is Hydro One's proposed depreciation expense for 2018 and further years appropriate?

VECC's has no submissions under this issue.

45. Are the proposed other revenues for 2018 – 2022 appropriate?

Apart from concerns related to HONI's proposed miscellaneous service charges, which are addressed under Issue #54, HONI's proposed Other Revenues for 2018-2022 are appropriate.

HONI's Other Revenues consist of: i) regulated revenues from OEB-approved specific service charges and the Standard Supply Service charge set by the OEB and ii) unregulated revenues where charges are determined by HONI based on the cost of the work performed. Historically (2015-2016), Other Revenues have averaged about $55 M per year and are forecasted to be in the order of $50 M in 2017. In HONI's Application these revenues were forecast to increase to $56 M by 2022, primarily due to higher proposed rates for joint use (i.e., pole attachments) and higher miscellaneous service charges[40].

During the oral proceeding HONI revised its proposed Other Revenues to reflect changes to its proposed miscellaneous charges and lower unregulated revenues due to a change in vegetation management practices with respect to clearing around third-party equipment[41]. As a result of these revisions the forecast for Other Revenues falls to $47 M for 2018 and then increases annually to $49.4 M in 2022.

On July 12, 2018, the OEB issued a Decision on Pole Attachment Matters and Procedural Order No. 8, in which the OEB established a separate process for considering HONI's proposed joint use charges related to telecom equipment. As result, the proposed telecom joint use charges are not addressed in this argument.

With respect to the balance of HONI's proposed Other Revenues, VECC's only comments and issues are with respect to the proposed charges and resulting revenues related to miscellaneous service charges and these are addressed under Issue #54.

H. LOAD AND REVENUE FORECAST

46. Is the load forecast methodology including the forecast of CDM savings appropriate?

47. Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

1. Customer Count

[40] Exhibit E1, Tab 1, Schedule 2, pages 1-3
[41] J 11.2

In 2017 the actual customer counts for HONI's Residential[42] and General Service Classes represented over 97% of HONI-Distribution's total customer count[43]. Furthermore, the forecast Residential and General Service customer count is primary driver for the forecast customer counts for the Street Light, USL and Sentinel Light classes[44]. As a result, VECC's submissions will focus on the reasonableness of HONI's forecasts for these customer classes.

1.1 Total Residential Customer Count – Excluding Acquired Utilities

Over the past six years, the change in HONI Residential customers as a percentage of the change in Ontario Households has varied but consistently exceeded the percentage (13.6%) used by HONI in its updated forecast nominally based on 2018 figures. VECC believes that the change in HONI Residential customers should be based on the four-year historical averages (15.9%) rather than the forecast 2018 figure (13.6%) as pst variability suggests that the historical average will provide a more accurate medium-term projection of growth.

HONI's total Residential[45] customer count (excluding the Acquired Utilities) forecast is derived by determining the forecast increase in Residential customer count for each year and adding this to the previous year's customer count[46]. The forecast increase in customer count for each year is determined as a percentage of the increase in number of Ontario households forecast for the same year. The forecast number of households in Ontario[47] is based on a consensus forecast for housing starts, net of demolitions.

For purposes of the initial Application, the actual values up to 2016 were used and the consensus forecast for housing starts was based on forecasts prepared in late 2016/January 2017[48]. The percentage applied to the forecast change in Ontario households to derive the change in Residential customers was 15.1% and was based on the forecast increase in 2017 Residential customers as a percentage of the forecast increase in total number of 2017 Ontario households. This is shown in the following Table which is based on Exhibit I, Tab 43, Schedule VECC-71 a) – Excel File Attachment.

[42] Including Seasonal
[43] Exhibit I, Tab 46, Schedule Staff-219, Table E.4 (Updated)
[44] J.10.05, Q02-01
[45] Includes Residential-Medium Density (R1), Residential-Low Density (R2), Urban Residential (UR) and Seasonal
[46] See Exhibit I, Tab 43, Schedule VECC-71 (a) & Attachment 1 and J.10.05, Q02-01
[47] Exhibit I, Tab 47, Schedule CME-80 (a) (iv) and Exhibit I, Tab 43, VECC 68 (a) (i)
[48] Exhibit E1, Tab 2, Schedule 1, page 37, Table E.2

Forecasting Retail Total Number of Residential Customers: Intial Application						
	2017	2018	2019	2020	2021	2022
Ontario Number of Households / Customers						
Level	5,160,306	5,216,630	5,273,377	5,330,182	5,386,556	5,441,607
Change	57,179	56,324	56,747	56,805	56,374	55,051
Retail Total Number of Residential Customers (R1 + R2 + Seasonal + UR)						
Change (1)	8,639	8,510	8,574	8,582	8,517	8,317
Level (2)	1,141,431	1,149,941	1,158,514	1,167,097	1,175,614	1,183,932
Residential Change/Household Change	0.15109	0.15109	0.15109	0.15109	0.15109	0.15109

(1) Given the information available at the time of forecast, change in the total number of retail residential customers in 2017 was forecast to be 8,639, which is more than the 3-year average change since since 2014. For the years 2018 to 2022, the change varies in proportion to change in the forecast of Ontario number of households / customers.
(2) Forecast for each year equals change in the total number of customer in that year plus forecasst in the prior year.

For purposes of the Residential customer count forecast update provided during the interrogatory process, actual data for 2017 was used and the forecast of Ontario households was updated to reflect a consensus forecast of Ontario housing starts using forecast from late 2017/early 2018. Furthermore, the percentage applied to the forecast change in Ontario households to derive the change in Residential customers was revised to 13.6% and was based on the forecast increase in 2018 Residential customers versus the forecast increase in 2018 Ontario Households. Again, this is shown in the following Table based on J.10.05, Q02 – Excel File Attachment.

Forecasting Retail Total Number of Residential Customers: Interrogatory Update					
	2018	2019	2020	2021	2022
Ontario Number of Households / Customers					
Level	5,226,439	5,283,086	5,338,836	5,394,993	5,450,608
Change	60,982	56,647	55,750	56,157	55,615
Retail Total Number of Residential Customers (R1 + R2 + Seasonal + UR)					
Change (1)	8,285	7,696	7,574	7,629	7,556
Level (2)	1,149,542	1,157,238	1,164,812	1,172,441	1,179,997
Residential Change/Household Change	0.1359	0.1359	0.1359	0.1359	0.1359

(1) Change in the total number of retail residential customers in 2017 was 8,465. For the years 2018 to 2022, the change varies in proportion to change in the forecast of Ontario number of households / customers.
(2) Forecast for each year equals change in the total number of customer in that year plus forecast in the

VECC has no issues with the general methodology, i.e., basing the change in HONI's Residential customer count on a percentage of the change in Ontario households. However, VECC does take issue with how HONI has established the percentage to be used. First, in the original Application, the ratio used (15.1%) was based on the forecast HONI Residential and total Ontario household counts for 2017 – but there was no explanation as to how the Residential forecast for 2017 was determined. Similarly, for the update (which HONI is now proposing to adopt[49]) a ratio (13.6%) based on the forecast HONI Residential and total Ontario household counts for 2018 – but there was no explanation as to how the Residential forecast for 2018 was determined.

Set out below is information regarding the historical relationship between the change in HONI's Residential Customer count and the change in Ontario Households.

History: Residential Customers vs. Ontario Households

	2011	2012	2013	2014	2015	2016	2017
Residential Customers							
Urban Residential	159,086	167,672	169,795	170,976	208,639	213,199	215,844
Residentil-Medium Density	402,173	403,304	409,901	416,493	432,519	441,836	447,647
Residential-Low Density	368,479	370,995	373,980	373,551	328,170	328,766	330,514
Seasonal	157,017	153,653	153,253	153,957	153,498	148,991	147,253
Total	1,086,755	1,095,624	1,106,929	1,114,977	1,122,826	1,132,792	1,141,258
Change		8,869	11,305	8,048	7,849	9,966	8,466
Ontario Households							
Total ('000's)	4,846.4	4,899.4	4,948.2	4,994.6	5,045.6	5,103.7	5,165.5
Change		53,000	48,800	46,400	51,000	58,100	61,757
Change in Residential #/ Chagne in Households		0.167339623	0.231659836	0.173448276	0.153901961	0.171531842	0.137085674

Sources
1) Residential Customers: Exibit I, Tab 47, Schedule Staff-219 Table E.4
2) Ontario Householda (2011-2016): Exhibit E1, Tab 2, Schedule 1, Attachment 1
3) Ontario Households (2017): Based on the J10.05-Q02-01 which reports 5,226,439 Households for 2018 as a 60,982 change from 2017
4) It should be noted that the Residential customer count for 2017 is based on actuals up to June 2017 and forecast values thereafter - per JT 3.18-5 b)

As the foregoing table shows the historical ratio of change in Residential customers versus Ontario Households has varied from year to year without exhibiting any definite trend. However, the ratio for each of the past 6 years has exceeded the ratio (13.6%) used by HONI in its updated forecast.

VECC notes that in cross examination[50] it attempted to explore the reason why the updated Residential forecast was lower even though the forecasted number of housing starts had increased. In their oral testimony, HONI witnesses attributed the lower forecast the fact the actual Residential customer count for 2017 as used in the Update was lower than that used in the forecast. While this makes some contribution to the reduction, the major reason for the lower Residential customer count forecast in the Update is the use of 13.6% as opposed to 15.1%. If, for purposes of the Update, the 15.1% had been applied to the Updated forecast Ontario Household changes for 2018-

[49] JT 3.18-5
[50] Volume 10, pages 97-98

2022 then the result 2022 Residential customer count would have been 1,184,339 – a value higher than the original 2022 forecast of 1,183,932 even using the lower actual 2017 customer count as the starting point. This is illustrated in the following table.

Forecast Total Number of Residential Customers:						
Updated Forecast with Original Residential/Ontario Household Ratiio						
	2017	2018	2019	2020	2021	2022
Ontario Number of Households / Customers						
Level	5,165,457	5,226,439	5,283,086	5,338,836	5,394,993	5,450,608
Change		60,982	56,647	55,750	56,157	55,615
Ratio: ResidentialChange/ Total Household Change		0.151086	0.151086	0.151086	0.151086	0.151086
Retail Total Number of Residential Customers (R1 + R2 + Seasonal + UR)						
Change (1)		9,213	8,559	8,423	8,485	8,403
Level (2)	1,141,257	1,150,470	1,159,029	1,167,452	1,175,937	1,184,339
Residential Change/Household Change		0.1511	0.1511	0.1511	0.1511	0.1511
Sources:	1) Ontario Households: JT.10.05-Q02-01					
	2) Residential Change/Ontario Household Change - per Original Application: Exhibit I, Tab 43, Schedule VECC-71 a) – Excel File Attachment					
	3) Residential Count (2017): Calculated from J.10.05, Q02 – Excel File Attachment.					
	4) Residential Change: Household Change * 0.151086					

VECC submits that it would be more appropriate for HONI to base the ratio on recent actual values. Adopting a three year average based on the most recent three years for which complete data[51] is available (2014-2016) would yield a ratio of 16.6%. Using four years of data (i.e., including 2017 which is only partially based on actuals) yields a ratio of 15.9%. VECC submits that the Board should direct HONI to revise its forecasts Residential customer count for 2018-2022 to reflect this latter percentage. The Board should also direct that this revised Residential customer count forecast be used in the derivation of the forecast customer counts for the Street Light and Sentinel Light classes.

1.2 Residential Customer Class Breakdown – Impact of Reclassification

HONI fails to account for the likely reclassification of R2 customers to the higher density R1 customer class, as it does for the reclassifications for R1 to UR.

[51] The 2017 customer count values reported in the response to Staff 219 only use actual values up to June 2017 and forecast values thereafter – per JT 3.18-5 b)

In response to interrogatories HONI explained[52] that the Retail customer count was broken down between customer classes based on historical shares and also adjusted for customer reclassification after 2017. The initial allocation to classes and adjustments due to reclassification are set out in JT3.18-6 a) – Excel Attachment. These reclassification adjustments incorporate not only the results of the most recent rate class review[53] but also a forecast of subsequent reclassifications that are likely to occur during the Customer IR period.

During the oral proceeding VECC inquired as to why the number of customers shifted between classes increase throughout the forecast period for all classes except R2. HONI's response was that "as R2 is the lowest density rate class, no customers are expected to be reclassified into the R2 class from the higher density rate classes (R1 and UR)"[54]. In VECC's view what this response, and indeed the overall forecast of customer reclassifications, fails to account for is the likelihood that some customers will be reclassified from R2 to R1 during the CIR period similar to the how the forecast calls for some reclassification from R1 to UR during the period.

VECC has insufficient information to recommend what an appropriate forecast of customer reclassifications from R2 to R1 would be. The Board should direct HONI to address this deficiency in its next load forecast.

1.3 GS Customer Count – Excluding Acquired Utilities

HONI's General Service long-term customer count projection does not appear to have been updated to reflect the impact of Ontario's improving economic outlook.

In response to interrogatories, HONI noted that, given the information available at the time of the original Application, the change in the total number of retail general service customers in 2017 was forecast to be -23 which was significantly more than the recent three year average of -1,766 per year. Based on the economic outlook, the latter figure was considered to be too low. Thus, HONI was assumed that the average annual change over the 3 years before 2014, +261, was a better measure of annual change in long run. Thus, the annual change was assumed to converge towards this value between 2018 and 2022[55].

For purposes of the load forecast update provided with the interrogatory responses, HONI noted that the actual change in the total number of retail general service customers in 2017 was -485. As this too was significantly less, in absolute value, than the 3-year average -1,766 per year prior to 2017 and given the economic outlook, the

[52] Exhibit I, Tab 43, Schedule VECC-71 b)
[53] Exhibit G1, Tab 2, Schedule 1, page 1
[54] J 10.5-Q4
[55] Exhibit I, Tab 43, Schedule VECC-71 (a) - Attachment 1

latter figure was still considered to be too low. As a result, it was assumed (as in the original forecast) that the average annual change over the 3 years before 2014 (+261) is a better measure of annual change in long run. So similar to the original forecast, the annual change was assumed to converge towards this value between 2018 and 2022[56]. However, given the actual change in the total number of retail GS customers for 2017 was less than originally forecast, the overall updated forecast for GS customers is lower for each of the years 2018-2022.
Again, VECC noted during the oral proceeding[57] the fact that the GS customer counts were lower despite the Update using a higher GDP forecast. HONI's explanation was that the 2017 GDP value had increased and it was the subsequent growth rates in GDP that drove the growth in GS customers.

However, VECC notes that in the economic outlook used in the updated load forecast calls for annual growth rates in GDP that are equal to those in the original forecast for the years 2019, 2021 and 2022 but higher growth rates for the years 2017, 2018 and 2020[58]. VECC also notes that, despite the higher economic growth now forecast for the Update, HONI did not change its value for the long-run annual change in the total number of retail general service customers (i.e., 261).

VECC submits that the forecasted higher growth in GDP used in the Update will lead to higher long run value for the annual change in the total number of retail general service customers. However, there is insufficient information for VECC to make an informed recommendation as to what the updated long run value should be. The Board should direct HONI to address this issue in its next load forecast.

Volumetric Forecast Methodology
HONI's Retail customer load (this excludes embedded utilities and the Sub-Transmission customers and represents over 60% of the total load) is forecast using a variety of models: i) Monthly econometric model, ii) Annual econometric model and iii) an End-Use Model. The resulting forecast growth rates from all three models are considered in preparing the load forecast. The models themselves use a variety of economic drivers including Ontario GDP, Residential building permits, Personal Disposable Income per Household and Energy prices as well as weather data. The models are explained in the Application at Exhibit E1, Tab 2, Schedule 1, Appendices A, B & C.
For purposes of developing its load forecast, Hydro One forecasts what the load would be without any CDM impacts (from CDM initiatives implemented in 2006 and after) and then adjusts (i.e., reduces) the resulting load forecast for the persisting effect of historic

[56] J.10.05-Q02-01
[57] Volume 10, pages 100-101
[58] See Exhibit E1, Tab 2, Schedule 1, page 38 (Table E.3) and Exhibit I, Tab 47, Staff 219, Table E.3 (Updated)

CDM initiatives plus the forecast impact of future initiatives[59]. However, the values used for historic savings from i) Codes and Standards and ii) Efficiency Programs are not based on actual savings in HON' service area but rather were estimated as a percentage of the total provincial savings reported by the IESO/OPA. This calculation is set out in 43-VECC-75 – Attachment 1. The results are summarized in VECC-75 f) and copied below:

f) The table below provides the 2006-2016 CDM savings by category used in our load forecast:

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
EE programs (2006-2016)	200,490	425,706	488,358	576,085	626,212	715,242	776,780	868,734	989,181	1,046,627	1,104,456
Code and Standards	-	15,123	15,124	45,379	60,508	151,559	238,276	266,013	472,001	617,370	762,277

Exhibit I-43-VECC-075 Attachment 1 (MS Excel format) provides the detailed calculation used to determine the savings attributed to "savings from the historical programs" for Hydro One broken down into various OPA categories.

VECC has concerns with: i) the historic CDM values used by HONI to establish historic use without CDM for purposes of developing its load forecast models; ii) the updated volumetric forecast (prior to CDM adjustment) provided by HONI in response to interrogatories and iii) HONI's forecast of its CDM results for 2017-2022, particularly its proposed used from purposes of establishing an LRAMVA.

1.4 <u>HONI's Historic CDM Values</u>

HONI"s load forecast methodology incorporates unreliable estimates of historic CDM impacts.

HONI acknowledges that the values it uses for historic CDM savings are "estimates" and do not reflect actual verified results[60]. HONI estimates the historic CDM impacts for both Codes & Standards and Energy Efficiency Programs as a percentage of overall provincial savings (as reported by the IESO/OPA). According to HONI[61] verified energy efficiency programs results are not available from the IESO for the period 2006-2010.

VECC has two issues with the approach used by HONI. The first is with respect to its claim regarding the non-availability of utility-specific information regarding energy efficiency program results for the period 2006-2010. HONI claims[62] that it approached the IESO and was informed that such information was not available. However, VECC

[59] Exhibit E1, Tab 2, Schedule 1, page 11
[60] Exhibit I, Tab 43, Schedule VECC-75 d)
[61] JT 3.18-2 b)
[62] J 10.5-Q8 a)

notes that other Ontario distributors[63] have obtained utility specific CDM results for this period for use in their load forecast models. VECC questions why HONI was unable to obtain similar information for its purposes.

VECC's second issue is that HONI does have reports from the IESO/OPA that set out its verified Energy Efficiency Program results for the period 2011-2016[64]. However, when these actual results are compared with the historical values used in HONI's load forecast[65] there are some anomalous results for the implied 2006-2010 Energy Efficiency Programs savings as illustrated below[66].

HONI Energy Savings (MWh)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
2006-2016 EE Programs (per VECC 75-1)	200,490	425,706	488,358	576,085	626,212	715,242	776,780	868,734	989,181	1,046,627	1,104,456
2011-2016 EE Programs (per JT 3.18-2)						88,000	150,000	235,000	427,000	741,000	909,000
Residual EE Program Savinç	200,490	425,706	488,358	576,085	626,212	627,242	626,780	633,734	562,181	305,627	195,456

After 2010 one would expect the persisting savings from 2006-2010 programs to remain constant or, more likely, decline overtime. However, the implied results for 2011 and 2012 are marginally higher than those for estimated for 2010 and the implied results for 2013 are higher still. When asked about these anomalies, HONI's response was that the differences are small[67]. VECC acknowledges that the inconsistencies are not large. However, the point is that there should be no such inconsistencies and there would not be if actual reported results were available and had been used. While these discrepancies may not introduce a material error in HONI's load forecast they do highlight the imprecision associated with HONI's approach to establishing both its historical CDM and (as discussed in subsequent sections) its forecast CDM impacts from future programs.

1.5 HONI's Updated Volumetric Forecasts (prior to CDM Adjustments)

The Updated Retail load forecast for 2018 is too low – it incorporates lower growth than the preliminary or "final" forecasts used in the initial Application despite higher economic

[63] Essex Power (EB-2017-0039, Exhibit 3, Attachment A); PUC Distribution Inc. (EB-2017-0071, Exhibit 3, page 12); Rideau St. Lawrence Distribution Inc. (EB-2015-0100, Exhibit 3, page 12).; Thunder Bay Hydro (EB-2016-0105, Exhibit 3, page 10) and Welland Hydro-Electric System Corp (EB-2016-0110, Exhibit 3, page 9)

[64] JT 3.18-2 a) & b)

[65] K10.5, Tab 17

[66] Exhibit K.10.5, Tab 17

[67] J 10.5-Q10 b)

and population growth forecasts. Volumetric forecasts should be increased to reflect those higher economic and population growth forecasts.

As noted above, HONI uses the results from three different models to develop its Retail customer load forecast (gross load prior to CDM adjustments). For purposes of the original application the growth rates (from 2016) were calculated using each model's forecast and, then, the average was applied to the 2016 gross load to obtain a preliminary load forecast. The calculation of the average growth rates used is set out in Exhibit I, Tab 43, Schedule VECC-76 c) and copied below.

Table 2: Calculation of Forecast Based on Different Models in GWh

	Forecast in GWh			Growth Rates (%)				
Year	Annual Econometric (1)	Monthly Econometric (1)	End-Use (2)	Annual Econometric	Monthly Econometric	End-Use	Average of Growth Rate	Preliminary Forecast (3)
2016	21,896	21,896	21,896					21,896
2017	21,757	21,771	21,784	-0.6	-0.6	-0.5	-0.6	21,771
2018	21,906	22,071	21,636	0.7	1.4	-0.7	0.5	21,871
2019	22,103		21,437	0.9		-0.9	0.0	21,869
2020	22,301		21,421	0.9		-0.1	0.4	21,959
2021	22,240		21,247	-0.3		-0.8	-0.5	22,931
2022	22,344		21,233	0.5		-0.1	0.2	22,971

(1) Equals corresponding value in response to (a) less retail general service that was moved to ST rate class.

(2) Equals corresponding value in response to (a) less Direct ST plus CDM value in 2016 so that the gross forecast would be consistent with the other forecasts, which include total CDM and not incremental CDM relative to 2016.

(3) Calculated using the average growth rate applied to 2016 gross base-load. Next, for the years 2021 and 2022 the Acquired Utilities load was added to the implied forecast. The latter step is performed to make it comparable with the forecast used in this application.

However, this preliminary forecast was considered too low compared to the economic outlook which was improving at the time of the forecast[68] and so it was adjusted upwards to arrive at the forecast used in the Application.

In response to interrogatories[69], HONI updated its economic outlook, incorporated actual 2017 information and prepared a revised load forecast using 2017 as the base year[70] which it is now adopting for purposes of the Application[71].

During oral proceeding VECC noted that the updated economic outlook was more positive than at the time the Application was prepared. However, despite this

[68] JT 3.18-7 a)

[69] Exhibit I, Tab 46, Schedule Staff-219

[70] J 10.5-Q14 f)

[71] JT 3.18-5

improvement in the economic outlook[72] the Retail Load forecast is now lower than that submitted with original Application. Furthermore, it is even lower than the preliminary load forecast prepared for the original Application. This is illustrated by the following table which compares the forecasts from the original Application (both the preliminary forecast and the proposed forecast) with the updated load forecast for the first three years of the CIR period.

Comparison of Retail Load Forecasts						
Year	Preliminary Forecast – per Application		Final Forecast – per Application		Updated Load Forecast	
	GWh	Growth	GWh	Growth	GWh	Growth
2016	21,896	-	21,896		21,896	
2017	21,771	-0.57%	22,071	0.8%	21,646	
2018	21,871	0.46%	22,134	0.29%	21,552	-0.43%
2019	21,869	-0.01%	22,168	0.15%	21,483	-0.32%
2020	21,959	0.41%	22,294	0.57%	21,510	0.13%
2021	22,931	4.43%	23,344	4.71%	22,573	4.94%
2022	22,971	0.17%	23,391	0.20%	22,646	0.32%
Source	VECC-76 c)		Exhibit E1, Tab 2, Schedule 1, Table 7		Staff-219 – Updated Table 7	

In response to questions during the oral proceeding HONI claimed that the updated forecast was lower due to the lower 2017 base-year load and pattern of growth rates for the economic variables[73]. VECC acknowledges that the base year (2017) value for the update load forecast is lower. However, the subsequent annual growth rates in the Updated load forecast are also lower in the first three years (2018, 2019 and 2020) than in the preliminary load forecast used for the original Application (see preceding table).

[72] This can be seen by comparing the forecast for economic variables in Table E.3 of the Application with the updated Table E.3 in Staff-219.
[73] J 10.5-Q14 f)

In contrast, a comparison of the growth rates for the underlying economic variables[74] for the years 2018, 2019 and 2020 indicates that for:

- GDP – the growth rates in the Update are higher in 2018 and 2020 and the same for 2019[75].
- Population – the growth rates in the Update are higher in all three years[76].
- Housing Starts – the growth rates in the Update are lower in 2018 and 2019 but higher in 2020. However, the resulting growth rate for number of Ontario Households is higher in 2018 but lower in 2019 and 2020[77].

Overall, the change (as between the Application and the Update) in forecast growth rates for various economic variables is mixed for 2019 and 2020 (some higher/some lower). However, the Update exhibits higher 2018 forecast growth for GDP, Population and Households which are all inconsistent with the (now) forecast lower energy growth rate for 2018. As result, VECC submits that the Updated Retail load forecast for 2018 is too low and should be revised upwards. VECC recommends that, at a minimum, the revised value be set that the 2018 value as used in the original Application. The values for 2019 and onwards would then also need to be revised upwards accordingly.

VECC notes there is a similar issue with the volumetric forecast for embedded customers. In the original forecast the forecast increase for 2018 (over 2017) was 0.126%; whereas in the Updated forecast the increase is 0.115%[78]. This reduction in the forecast growth rate for 2018 is inconsistent with the higher forecast growth rates in the Update for both GDP and Households. As result, VECC also submits that the Updated Embedded customer load forecast for 2018 is too low and should be revised upwards. VECC recommends that, at a minimum, the revised value be set that the 2018 value as used in the original Application. The values for 2019 and onwards would then also need to be revised upwards accordingly.

1.6 HONI's Forecast CDM Results

The forecast CDM savings that HONI has assumed for 2017-2020 CDM programs are not based on specific assumptions regarding the success of HONI's CDM initiatives and cannot be broken down by year of implementation.

---

[74] J 10.5-Q12

[75] This can be seen by comparing the growth rates forecasts in Table E.3 of the Application with the updated Table E.3 in Staff-219

[76] Again, this can be seen by comparing the growth rates forecasts in Table E.3 of the Application with the updated Table E.3 in Staff-219

[77] The forecast Household growth rates for both the Application and the Update are set out in the tables provided above in Section 1.1

[78] This can be seen by comparing the growth rates forecasts in Exhibit E1, Tab 2, Schedule 1, Table 7 of the Application with the updated Table 7 in Staff-219

For purposes of the Application, HONI used the IESO's 2016 Ontario Planning Outlook (OPO) which provides a forecast of persisting impact of past CDM and future CDM at the provincial level[79]. The provincial forecast is summarized below[80].

2016 OPO

TWh	2017	2018	2019	2020	2021	2022
Codes and standards (Implemented by 2015)	6.3	6.9	7.3	7.4	7.4	7.4
Codes and standards (Implemented 2016 and beyond)	0.0	0.2	0.3	0.4	0.6	0.9
Historical program persistence (2006-2015)	6.4	5.7	5.5	4.9	4.4	3.6
Forecast savings from planned programs (2016-2020)	3.3	5.0	6.4	7.9	8.0	7.8
Planned savings from future programs & Codes and Standards	0.0	0.0	0.0	0.0	0.6	1.3
Total TWh	15.9	17.8	19.5	20.7	20.9	21.1

HON calculated its forecast CDM savings by: i) removing the impacts of CDM activity of transmission connected customers (data from IESO) in order to determine the contribution of all LDCs, ii) adjusting the results for losses since the 2016 OPO values are measured at point of generation not at point of delivery to customers and iii) basing HONI's share on 13.71% for EE programs and 16.56% for codes and standards. The 13.71% represents HONI's share of total LDC savings for the period 2011-2014 while the 16.56% represents HONI's share of the targeted savings for the period 2015-2020. The results are set out below[81].

HONI energy savings

	2017	2018	2019	2020	2021	2022
C&S	888,489	993,685	1,065,658	1,101,480	1,088,469	1,089,382
EE program	1,150,879	1,239,857	1,381,493	1,477,601	1,513,527	1,537,924
Total	2,039,369	2,233,541	2,447,151	2,579,081	2,601,995	2,627,306

In VECC's view it is important for the Board to recognize that the forecast savings from EE programs is not based on either: i) the persisting saving from HONI's actual verified results from 2006-2016 programs[82] or ii) a specific forecast by HONI as to the impacts of programs implemented in the years 2017-2022[83]. Indeed, the forecast is really just an estimate the same way the historical 2006-2016 HONI EE program savings used in the load forecast are an estimate.

Furthermore, HONI is unable to breakdown the total EE program impacts attributable to all LDCs by program year (i.e., the impact in 2018 of LDC EE programs implemented in

[79] Exhibit I, Tab 43, Schedule VECC-75 j)
[80] Exhibit I, Tab 43, Schedule VECC-75-05
[81] Exhibit I, Tab 43, Schedule VECC-75-05
[82] Exhibit I, Tab 43, Schedule VECC-75 d)
[83] J 10.5-Q16 c)

2018)[84]. As result, HONI is not able to determine (by applying 16.56%) what it has used as an "estimate" in the load forecast for the impact in specific years of its EE programs

While this level of detail is not required for the load forecast, it is required in order to establish the appropriate LRAMVA thresholds for each year.

1.7 HONI's Proposed LRAMVA

The Board should reject HONI's proposed LRAMVA as HONI is unable to identify the annual CDM savings from 2017-2020 programs included its load forecast.

HONI is proposing to establish a Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) through which HONI will seek recovery of[85]:

- lost revenues due to the incremental savings in 2018 from programs implemented in 2017-2018;
- lost revenues due to the incremental savings in 2019 from programs implemented in 2017-2019; and
- lost revenues due to the incremental savings in 2020 from programs implemented in 2017-2020.

The LRAMVA calculates lost revenues based on the rates applicable for the year concerned and the difference between the actual EE programs savings and the EE program savings assumed in the load forecast for purposes of setting the rates. For purposes of these calculations HONI has set out the following as the LRAMVA threshold values for 2018, 2019 and 2020[86]:

- For 2018 – 314.6 GWh based on the difference between the EE program savings in 2016 a result of 2015 and 2016 programs and the savings anticipated in 2018 based on the EE program saving from 2015-2018 EE programs.
- For 2019 – 473.2 GWh based on the difference between the EE program savings in 2016 a result of 2015 and 2016 programs and the savings anticipated in 2019 based on the EE program saving from 2015-2019 EE programs.
- For 2020 – 631.0 GWh based on the difference between the EE program savings in 2016 a result of 2015 and 2016 programs and the savings anticipated in 2020 based on the EE program saving from 2015-2020 EE programs.

Since the LRAMVA calculations and recovery are customer class specific, HONI was also requested to provide a breakdown by customer class, which it did in response to J 10.5-Q23.

VECC has a number of concerns regarding HONI's LRAMVA proposal. The calculation for each year is based on the following assumptions regarding the annualized impact of

---

[84] J 10.5-Q 17 and J 10.5-Q 18
[85] JT 3.18-4 a) and Oral Proceeding Volume 3, page 122
[86] J 10.5-Q22

EE programs implemented in 2015-2020[87] and is based on Hydro One's verified 2015 and 2016 CDM program results and the 2017-2020 forecast CDM program amounts required to achieve the 2020 Hydro One CDM target of 1,159,020,000 kWh.

IMPACT OF HONI'S EE PROGRAMS (Annualized GWh)						
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
2015 Programs	335.5	316.4	313.1	312.9	311.7	310.4
2016 Programs	-	211.6	210.0	209.6	209.2	208.4
2017 Programs	-	-	160.1	160.1	160.1	160.1
2018 Programs				160.1	160.1	160.1
2019 Programs					160.1	160.1
2020 Programs						160.1
Total	335.5	528.0	683.2	842.6	1001.2	1159.0

VECC's first concern is that the calculation performed by HONI captures not only the assumed impact of EE programs implemented after 2016 but also captures the decline in persistence of 2015 and 2016 EE programs. For example the 314.6 GWh value proposed for 2018 as the impact of 2017 and 2018 EE programs is based on the difference between 842.6 GWh and 528.0 GWh[88] whereas the value should be 320.2 GWh (i.e., 160.1+160.1). There are similar issues with the proposed values for 2019 and 2020 which (based on the preceding table) should be 480.3 GWh and 640.4 GWh respectively.

VECC's next concern is that the customer class breakdown provided by HONI set out only impact on the billing determinants for each class (some of which are kWh while other are kW) – despite VECC specifically requesting that the kWh values also be provided for those classes that are demand billed[89]. As a result, VECC is unable to verify whether the customer class values reconcile with the total provided.

However, VECC's larger concern is that the 2015-2020 EE program impact assumptions HONI is proposing to use in order to calculate the LRAMVA threshold values are <u>not</u> the assumptions actually used by HONI in its load forecast which were established (as described earlier) on a totally different basis. Furthermore, as discussed earlier, HONI is unable to provide a schedule similar to the above table that breaks down the overall impact of EE programs that was used in its load forecast by implementation year[90]. As a result, HONI is unable to identify the estimated impact of 2017, 2018, 2019 and 2020 EE programs in 2018-2020 consistent with its load forecast.

[87] J10.5-Q22
[88] J 10.5-Q22
[89] J 10.5-Q23
[90] See also Exhibit I, Tab 43, Schedule VECC-75 a)

Given this shortcoming it is VECC's submission that HONI's proposed LRAMVA should not be approved as HONI is unable to provide the necessary information consistent with its load forecast.

48. Has the load forecast appropriately accounted for the addition of the Acquired Utilities' customers in 2021?

For the years 2017-2020 HONI's Retail load forecast does not include any retail sales to the customers served by the acquired utilities (Norfolk, Haldimand and Woodstock)[91]. However, the load forecast for the embedded distributor load (part of the Sub-Transmission class) does include the portion of Norfolk and Haldimand load that was historically embedded in Hydro One's distribution system. Then, for 2021 and 2020, the Retail load forecast includes the load forecast for the acquired utilities' customers, but the forecasted embedded distributor load excludes the portion of Norfolk and Haldimand load that was historically embedded in Hydro One's distribution system[92].

In VECC's view this treatment of acquired utilities load is appropriate.

91

92 Exhibit I, Tab 43, Schedule VECC-77 b)

I. COST ALLOCATION AND RATE DESIGN

49. Are the inputs to the cost allocation model appropriate and are costs appropriately allocated?

1. <u>Introduction</u>

For purposes of its Application HONI has provided two cost allocation models (CAM): one for 2018 the initial test year and a second for 2021 the first year the customers from the acquired utilities and their associated costs are included for purposes of setting rates[93].

With the exception of the specific adjustments made to the 2021 CAM to accommodate the customers of the acquired utilities, the cost allocation methodology employed is the same as that in the Board-approved 2017 cost allocation model[94]. Specifically with respect to the inputs used HONI notes:

- The revenue requirements used match those proposed for 2018 and 2021.
- The loads used are based on its load forecast and the load profiles have been updated to latest hourly data available.
- The other allocators and weighting factors used are the same as those previously used with the exception of Meter Capital and Meter Reading which has been updated to reflect the number of meters, the number of manually read meters and the cost per meter[95].

2. <u>Contributed Capital, Accumulated Depreciation and Street Light Adjustment Factor</u>

During the interrogatory process errors were identified in the cost allocation models regarding the treatment of contributed capital and accumulated depreciation[96] as well as with respect to the application of the Street Light Adjustment Factor[97]. HONI has noted that the impact of these errors is small and committed to correcting them during the draft rate order phase of the proceeding.

3. <u>Density</u>

Excluding the adjustments made to the 2021 CAM to account for the acquired utility customers (see Issue 56 below), VECC has only two concerns regarding HONI's cost allocation methodology. The first is in regard to the density factors used for the various customer classes. In both the 2018 and 2021 models the density factors used for the

---

[93] Exhibit G1, Tab 1, Schedule 1, page 2 and Exhibit G1, Tab 3, Schedule 1, pages 1-2
[94] Exhibit G1, Tab 3, Schedule 1, page 3
[95] Exhibit I, Tab 46, Schedule VECC-88 and JT 3.18-11
[96] Exhibit I, Tab 49, Schedule Staff 236
[97] Exhibit I, Tab 49, Schedule Staff 237

existing customer classes are the same as those established in EB-2013-0416 and used in previous applications[98].

During the IR process VECC inquired[99] as to the basis for HONI's decision to continue to use the same density factors. HONI responded that it had no information to suggest that the relative cost of serving the different density areas had changed. During the Technical Conference HONI expanded[100] on its response and indicated that the density factors are driven by the relative cost of assets and OM&A required to different density areas and that there had been no fundamental changes in this regard.

VECC has two issues with HONI's response. First, the density factors are based on the relative cost per customer of serving customers in different density areas[101]. While the relative costs of the assets and OM&A associated with the different density areas may not have changed over time, the relative customer density (e.g. customers per km) in what the original Density Study[102] considered to be high, medium and low density areas may well have changed overtime which would impact the relative values of the density factors.

VECC's second issue is that for some of the customer classes (i.e., Seasonal, GSe and GSd) the values are interpolated based on their customer densities relative to that of the other customer classes. Again, to the extent the densities (e.g., customers/km) for these classes relative to the densities for other customer classes has changed over time the "interpolation" results will change.

Neither of these concerns was addressed in HONI's responses. Furthermore, VECC notes the original Density study used 2010 data and almost ten years have already passed since that point in time. VECC submits that the Board should direct HONI to specifically review the density factors used in the cost allocation prior to filing any future cost allocation model.

4. *Responsibility for Investments to Improve Reliability*

A substantial share of HONI's capital costs are associated with maintaining a higher level of reliability. These investments are being made ~~for the benefit~~ to address the needs of commercial and industrial customers who have high costs associated with power interruptions and the duration of power interruptions. But for the presence of these customer classes, HONI would choose to sacrifice reliability to control costs. HONI should allocate the capital costs associated with maintaining a higher level of

[98] Exhibit G1, Tab 3, Schedule 1, page 5
[99] Exhibit I, Tab 46, Schedule VECC-89
[100] JT 3.18-12
[101] EB-2012-0136, Exhibit D, Tab 1, Schedule 1, pages 2-3
[102] EB-2012-0136, Exhibit D, Tab 1, Schedule 1, Attachment 1

reliability to the commercial and industrial customers for whom those investments are primarily undertaken.

4.1 Investments to improve reliability

Many of HONI's largest capital programs are intended to improve reliability (or equivalently failure risk).

Program	**Role of Reliability/Failure Risk**	**Plan Period Cost ($M)**
SR-02 Mobile Unit Substation Program	Primary Trigger	26.9
SR-03 Station Spare Transformer Purchases Program	Secondary Trigger	18.6
SR-04 Distribution Station Planned Component Replacement Program	Primary & Secondary Trigger	11.0
SR-05 Distribution Station Feeder Protection Upgrade	Primary Trigger	12.1
SR-06 Distribution Station Refurbishment	Primary Trigger	148.1
SR-09 Pole Replacement Program	Primary Trigger	579.0
SR-10 Distribution Lines Planned Component Replacement Program	Secondary Trigger	35.3
SR-12 Distribution Lines Sustainment Initiatives	Secondary Trigger	151.7
SS-03 Reliability Improvements	Secondary Trigger	33.1
SS-06 Worst Performing Feeders	Primary Trigger	49.9

Similar expenditures have been made for decades, and likely represent a substantial portion of the value of HONI's capital stock associated with poles, transformers, etc. as these capital assets have been replaced where there is a moderate risk.

For many of these capital programs, including pole replacements which represent the bulk of spending, a choice which would result in a deterioration of service reliability is rejected in favour of a substantially more expensive choice which would maintain or improve reliability.

For some of these programs, the balance being struck between cost and reliability is obfuscated by the absence of a business case seriously considering plausible alternatives.

The choice is not between cost ineffective complete reliance on reactive replacements and these capital programs. To the extent capital programs are cost effective, they will obviously be undertaken. But there remains a choice between undertaking system renewal only as cost-effective avoidance of replacement costs, and undertaking further system renewal to maintain current or improved levels of reliability. HONI has not presented any analysis to demonstrate that its capital programs are cost effective relative to emergency replacements give the quantified incremental risk of the replaced asset failing.

The choice is also not between allowing a backlog of capital needs to accumulate and meeting capital needs. A "backlog" implies a different standard will be set in future, which will require making up the different between the work performed under the proposed standard and the future standard. The choice is better characterized as being between replacing poles where there is a marginally elevated risk of pole failure and replacing poles where there is a significantly elevated risk of pole failure. In other words, a trade-off is being made between price and reliability which is capitalized.

4.2 The beneficiary of investments to improve reliability

HONI's evidence indicates that commercial and industrial customers have substantial costs associated with power interruptions and the durations of power interruptions which are not present for residential customers.

As noted by Mr. Fenrick, research from the Lawrence Berkeley National suggest that small commercial and industrial electricity customers have high costs associated with interruptions and the duration of interruptions. Their financial losses associated with such interruptions exceed their total current bill:

> MR. FENRICK: Those are the findings from the U.S.Department of Energy, the Lawrence Berkeley National Laboratory. Those would be the findings they found that electricity is an extremely important commodity to C&I customers, and even small C&I customers. The value of it is enormous within our economy.
>
> MR. SHEPHERD: So then this Board should be able to conclude that if Hydro One was able to get to perfect reliability for those small C&I customers, they'd pay another $475 million a year for that result, right?
>
> MR. FENRICK: If they were able to get to perfect reliability?
>
> MR. SHEPHERD: Perfect reliability.

> MR. FENRICK: Yes, I believe that would be – the conclusion would be that based on the study cited, if Hydro One could get to perfect reliability, that's what the small C&I would be willing to pay to get that. That's what flows out of there.[103]

HONI witnesses agreed with those results:

> MR. SEGEL-BROWN: ...
> Could we turn to page 3 of my compendium? This is the Fenwick total factor productivity study done for Hydro One and at table 13, he shows the interruption related costs by rate class. Now, I assume that you are not familiar with these specific figures, but do those figures match -- well, do you have any reason to doubt that these figures reflect the approximate magnitude of the costs of interruptions by rate class?
>
> MR. JESUS: No, I would agree.
>
> MR. SEGEL-BROWN: So you would agree that these reflect the approximate cost of interruptions by rate class?
>
> MR. JESUS: Based on Mr. Fenwick's study, if that's what he said.[104]

As noted by Mr. Shepard, the study was of costs, rather than willingness to pay.[105] However, as a matter of basic economic logic, consumers' willingness to pay must be equal to or greater than their direct financial losses because paying the amount of their losses would leave them as well off, even before accounting for unquantified value provided to those customers.

The fact that investments in reliability are undertaken primarily for the benefit of commercial and industrial customers is also reflected in HONI's customer engagement with residential customers.

When consumers were asked to trade-off a specific reliability impact against a specific price change, most consumers were willing to pay less than $0.30/month increase per year for a 10% increase in reliability, both in the telephone survey and online survey. In the telephone survey, 67% of consumers were not willing to pay an additional $0.30/m/y over five years for a 10% improvement in reliability, compared with 24% who were willing to pay.[106] In the online survey, 69% of consumers were not willing to pay an additional $0.30/m/y over five years for a 10% improvement in reliability, compared with 27% who were willing to pay.[107] Consumers were unwilling to accept even this very modest price increase for a substantial increase in reliability. This reflects the reliability investments are being made for the benefit of other customer classes.

---

[103] Hearing Transcript, Day 2, 133-134.
[104] Hearing Transcript, Day 8, 32-33.
[105] Hearing Transcript, Day 2, 134.
[106] Exhibit B1-1-1, Section 1.3, Attachment 1, Page 54.
[107] Exhibit B1-1-1, Section 1.3, Attachment 1, Page 63.

4.3 Implications for cost allocation

The capital costs associated with maintain a higher level of reliability should be allocated to the commercial and industrial customer classes for whom they are undertaken, and without whom a lower level of reliability would be maintained.

50. Are the proposed billing determinants appropriate?

VECC has no specific submissions on this topic other than to note that any changes made to the load forecast (per Issues #46 and #47) will lead to changes in the proposed billing determinants.

51. Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?

The results of the 2018 cost allocation[108] indicate that the status quo revenue to cost ratios for all classes are within the Board's approved policy ranges with the exception of the DG class[109]. For 2018, HONI proposes to increase the revenue to cost ratio for the DG class from 0.57 to 0.63. To maintain revenue neutrality the revenue to cost ratios for the Seasonal and USL classes (i.e., the two classes with the highest status quo ratios) were reduced to 1.09. The 0.63 value for the DG class is the maximum value that can be implemented while still meeting the Board's 10% total bill impact criterion[110].

VECC has no issues with HONI's proposed 2018 revenue to cost ratios. HONI's approach is consistent with the approach the Board has approved for other electricity distributors in their cost of service-based applications. The Board has acknowledged that "as a practical matter there may be little difference between a revenue-to-cost ratio of near one and the theoretical ideal of one"[111] and the Board's policy ranges define the degree of variation that is considered acceptable for each customer class. In VECC's view, these policy ranges remain appropriate for HONI, particularly in view of the concerns raised regarding the continuing appropriateness of HONI's density factors.

---

[108] As noted earlier HONI has acknowledged that a couple of corrections are required to the cost allocation methodology as used in the evidence. However, it has also indicated that these corrections are unlikely to have a material impact on the cost allocation results.

[109] Exhibit H1, Tab 1, Schedule 1, page 9

[110] Exhibit H1, Tab 1, Schedule 1, pages 8-9

[111] Application of Cost Allocation for Electricity Distributors – Report of the Board (EB-2007-0667), page 4

For 2019 HONI calculates the status quo revenue to cost ratio for each class by: i) determining the revenues based on 2018 rates and the 2019 forecast billing determinants and adding the 2018 miscellaneous revenues allocated to the class; ii) increasing the previous results for each class by a common factor such that the total (across all customer classes) equals the 2019 proposed revenue requirement; iii) increasing the 2018 costs allocated to each class by the overall increase in the revenue requirement between 2018 and 2019; and iv) dividing the results of step (ii) by the results of step (iii)[112]. Based on this approach the revenue to cost ratio for the DG class continues to be the only one that is outside (i.e., below) the Board's prescribed ranges. For 2019 HONI proposes that the ratio for the DG class be increased from a status quo value of 0.66 to 0.75, the maximum achievable within the Board's 10% total bill impact criterion[113]. Again, to maintain revenue neutrality the revenue to cost ratio for USL, Seasonal and R1 are all reduced to common value of 1.08[114].

A similar approach is also used for 2020 which results in the status quo revenue to cost ratio for all classes being within the Board's prescribed policy ranges and no adjustments required[115].

VECC has concerns regarding the approach HONI has taken to determining the status quo revenue to cost ratios for 2019 and 2020. The first concern is with respect to the determination of the revenues ascribed to each class. HONI determines this value by calculating the revenues based on the previous year's rates and the test year's forecast billing determinants and adding the class' previous year's miscellaneous revenues and increasing the results for each class by a common factor such that the total equals the test year's proposed revenue requirement. The test year's revenues from rates are then calculated by subtracting a share of the test year's miscellaneous revenues determined by increasing the previous year's allocated miscellaneous revenues by the percentage increase in miscellaneous revenue for the test year.

The concern is that this approach yields to a variation in distribution rate increases across even those customer classes where no change is being proposed to the revenue to cost ratio[116]. This variation in rate increases arises because the common adjustment factor applied to the sum of the revenues at current rates and the previous year's miscellaneous charges (e.g., 3.53% for 2019) in order to determine total test year revenues by customer class differs from the common adjustment factor applied to the previous year's miscellaneous charges (e.g., 1.87% for 2019) used to determine the

[112] Exhibit H1, Tab 1, Schedule 1, pages 4-5 and Exhibit H1 Tab 1, Schedule 2, page 2
[113] Exhibit H1, Tab 1, Schedule 1, page 9
[114] Exhibit H1, Tab 1, Schedule1, pages 9-10
[115] Exhibit H1, Tab 1, Schedule 1, pages 10-11
[116] Exhibit I, Tab 48, Schedule VECC 97 d)

miscellaneous revenues actually attributed to the customer class for the test year[117]. VECC also notes that this approach differs from that actually used in the cost allocation model where the common adjustment factor used to determine the test year revenues is only applied to the class' distribution revenues. Also, contrary to HONI's claim[118], the approach it uses to determine the test year revenues for 2019 and 2020 is not consistent with the approach used to adjust rates in IRM applications. In IRM applications the adjustment factor is only applied to the distribution rates and not to miscellaneous revenues.

HONI notes that the variation in the rate increases across customer classes is small for most customer classes. However, it does give rise to some anomalous results. For example, even though the revenue to cost ratio for R1 is being reduced in 2019, the proposed rate increase (3.7%) exceeds that for the R2 class (3.6%) where the revenue to cost ratio is being held constant. Also, in the case of the Sentinel class it gives rise to a materially higher 2019 rate increase (6.9%)[119].

VECC also notes there is an issue with HONI's basis for determining the 2019 and 2020 costs by customer class (i.e., the denominator in the revenue to cost ratio calculation). Increasing each class' previous year's allocated costs by the same percentage implicitly assumes that the allocation factors (e.g., customer counts and customer class demand) used for each class are increasing by the same percentage. However, this is not the case and the annual change in load forecast (i.e., the class energy, demand and customer count) varies across the customer classes. It is also inconsistent with the basis (as just described) for determining the revenues by customer class, which does take into account the load forecast for each customer class.

VECC submits that these shortcomings in HONI's approach for 2019 and 2020 can be addressed by using an approach similar to that outlined Exhibit I, Tab 48, Schedule VECC-97 e) and the Board should direct Hydro One to do so. Adopting this approach would reduce the variation seen in both the year over year rate increases as well as the year over year change in revenue to cost ratios.

For 2021 HONI has provided an updated cost allocation model that incorporates the acquired utilities' customers and costs. For most of the rate classes the status quo revenue to cost ratios are already within the Board's approved range. The four rate classes whose ratios require adjustment are the AUGe, AUGd, AR and AGSd, which are all new rate classes created as a result of incorporating the Acquired Utilities[120]. In all four cases the ratios are reasonably close to the Board's range such that the ratios

---

[117] Exhibit H1, Tab 1, Schedule 2, page 2
[118] Exhibit I, Tab 48, Schedule VECC-97 b)
[119] Exhibit I, Tab 48, Schedule VECC 97 d)
[120] Exhibit H1, Tab 1 Schedule 1, page 11

can be increased to the bottom end of the Board's range without any need for bill impact mitigation. To maintain revenue neutrality the ratios for the UR, R1, Seasonal and USL classes are all reduced slightly[121].

VECC has no concerns about HONI's proposed adjustments to the status quo revenue to cost ratios as determined by its 2021 cost allocation model. However, as discussed under Issue #56, VECC does have concerns regarding the 2021 cost allocation methodology and the changes made to incorporate the acquired utilities' customers.

HONI used the same methodology for 2022 as was used for 2019 and 2020 in order to determine the status quo revenue to cost ratios and the required rate increases by customer class. VECC has similar concerns regarding HONI's approach for 2022 as it has already outlined for 2019 and 2020.

52. Are the proposed fixed and variable charges for all rate classes over the 2018 –2022 period, appropriate, including implementation of the OEB's residential rate design?

<u>Introduction</u>

With the exception of the Residential and DG classes, HONI is proposing to maintain the current fixed-variable split for all its existing customer classes. For the DG class, HONI proposes that the fixed charge be reset for 2018 at the minimum system value determined by the cost allocation model and that this fixed charge remain unchanged for the 2019-2022 period. For the Residential classes HONI proposes to continue the transition to a fully fixed rate which for the UR class will be completed in 2020 for the R1, R2 and Seasonal classes will be completed in 2023[122].

For the acquired utilities' Residential customers, the transition to a fully fixed charge will be completed by 2020 such that the rate design will be based 100% on a fixed charge when the customers are incorporated into HONI' distribution business in 2021. For the acquired non-residential customers in the AUGe and AUGd classes, HONI proposes to maintain for 2021 and 2022 the same fixed variable split as approved in Woodstock Hydro's last cost of service application. For the acquired non-residential customers in the AGe and AGd classes, HONI proposes to use, for 2021 and 2022, a blended fixed-variable split based on a weighted average of the ratios approved for Norfolk Power and Haldimand Hydro in their last cost of service applications[123].

1. *<u>Residential Rate Design</u>*

---

[121] Exhibit Q, Tab 1, Schedule 1, Attachment 4
[122] Exhibit H1, Tab 1, Schedule1, pages 15-17
[123] Exhibit H1, Tab 1, Schedule 1, pages 15-17

The RRWF methodology provides for a smoother transition to a fully fixed Residential rate than HONI's proposed approach and HONI should be directed to adopt it.

In this Application HONI is continuing to use the phase-in periods approved by the Board in EB-2013-0416/EB-2015-0079: five years for the UR class and eight years for the R1, R2 and Seasonal classes[124]. However, the methodology used by HONI to determine the annual adjustments to the Residential fixed charges differs from that set out by the Board in the Revenue Requirement Work Form (RRWF). HONI claims that with its approach the presentation of the annual transition calculations is simpler and results in a smoother transition[125].

Board Staff, in its submissions[126], has set out a table comparing the annual total change in the fixed charged for each Residential class over the 2018-2022 period using the RRWF methodology and HONI's methodology. As Staff notes in its submissions, for each of the four existing Residential classes the variation in the annual change in the fixed charge is less using the RRWF methodology. The following table compares the annual change in the Residential fixed charge due solely to the policy of moving to a fully fixed rate (i.e., excludes the impact of the annual change in the revenue requirement). Again, when just the impact of policy change is considered, the RRWF methodology provides for a smoother transition (i.e., less year to year variability).

Impact of Residential Rate Design Policy on Fixed Charge ($)						
Class	Method	2018	2019	2020	2021	2022
UR	RRWF	2.49	2.56	2.61		
	HONI	1.92	2.55	3.64		
R1	RRWF	3.71	3.81	3.92	3.97	4.06
	HONI	2.71	3.15	3.55	4.37	4.79
R2	RRWF	7.57	7.69	7.84	7.95	8.09
	HONI	5.15	6.38	7.24	8.52	9.97
Seasonal	RRWF	3.92	3.96	3.96	3.97	4.10
	HONI	2.66	3.53	3.75	4.54	4.78
Sources: RRWF – Exhibit I, Tab 49, Staff-245 – Excel Attachment HONI - J 10.5-Q30						

Overall, HONI's approach does not achieve a "smoother" transition. VECC agrees with Board Staff's submission[127] that HONI should be directed to adopt the method in the

[124] Exhibit H1, Tab 1, Schedule 1, page 15
[125] Exhibit I, Tab 49, Schedule Staff-245 a)
[126] Board Staff Submissions, page 153
[127] Page 154

RRWF for implementing the transition to fixed residential rates in accordance with the residential rate design policy.

2. *Non-Residential Rate Design*

VECC has no submissions with respect to HONI's rate design proposals for non-residential customers.

53. Are the proposed Retail Transmission Service Rates appropriate?

In Section 8 of Exhibit H1, Tab 1, Schedule 1 HONI has outlined the methodology it uses to determine its proposed Retail Transmission Service Rates (RTSRs) and notes that the methodology has previously been reviewed and approved by the Board. HONI also proposes to updates its proposed RTSRs for 2018 to 2021 to reflect changes in the underlying Uniform Transmission Rates as part of each year's Draft Rate Order process[128].

VECC has no issues with HONI's proposed RTSRs or its proposed annual updates.

54. Are the proposed specific service charges for miscellaneous services over the 2018 – 2022 period reasonable?

VECC's proposal to discontinue a number of miscellaneous charges and maintain its disconnection/reconnection charges at current levels is appropriate. However, HONI should also be directed to withdraw its proposed charges for Special Meter Reads-Retailer Requested (Rate Code 15).

For purposes of the current Application HONI completed a year-long time study of the tasks involved in providing miscellaneous services and the related costs and, in most instances the existing service charges were updated accordingly. In addition, the Application proposed the introduction of a number of new service charges and the elimination of several existing charges. The following table sets out VECC's understanding of the proposed service charges for 2018 along with the method used to establish the proposed charges for 2018-2022 per the original Application, as well as those existing service charge that HONI propose to discontinue as of 2018[129]. During the oral proceeding[130], HONI revised its proposals regarding specific service charges by withdrawing its proposed charges for a number of activities and maintaining the current charges for disconnection/reconnection activities. These changes are also identified in the Table.

[128] Exhibit H1, Tab 1, Schedule 1, page 29

[129] A number of the services that are being discontinued are one for which 2017 rates are approved but, as noted in the table, the service is not currently provided – see Exhibit H1, Tab 2, Schedule 3, page 11

[130] Volume 11, pages 6-7

		Initial Application				Oral Proceeding Update
Charge	Rate Code	Rate Status	2017 Rate	Proposed 2018 Rate	Basis for 2018-2022 Rate	
Statement of Account	2	Continued	$15	$13	Fixed – Set Below Cost	Discontinued
Pulling Post Dated Cheques	3	Discontinued	$15 -currently not provided	N/A	N/A	
Duplicate Invoice	4	Continued	$15	$13	Fixed – Set Below Cost	Discontinued
Request for Other Billing Info	5	Continued	$15	$13	Fixed – Set Below Cost	Discontinued
Easement Letter - Written	6 a)	Continued	$15	$86.90	Annual Incr. – Cost Based	
Easement Letter - Web	6 b)	Continued	$15	$25	Fixed – Historic Value	
Income Tax Letter	7	Continued	$15	$13	Fixed – Set Below Cost	Discontinued
Notification Charge	8	Discontinued	$15 -currently not provided	N/A	N/A	Discontinued
Account History	9	Continued	$15	$13	Fixed – Set Below Cost	Discontinued
Credit Reference/ Check	10	Continued	$15 + Agency Cost	$13	Fixed – Set Below Cost	Discontinued
Returned Cheque Charge	11	Continued	$15	$7	Fixed – Set at Cost	

Charge to Certify Cheque	12	Discontinued	$15 -currently not provided	N/A	N/A	
Legal Letter Charge	13	Continued	$15	Actual Incurred Costs	Charged at Actual Cost	Discontinued
Account Set Up/Change Occupancy	14	Continued	$30	$38	Fixed – Average Cost	
Special Meter Read	15	Continued	$30	$90	Fixed – Set at Cost	
Acct. Collection – No Discon.	16	Continued	$30	$100	Fixed – Average Cost	
Acct. Collect. – No Discon. – After Reg. Hrs	17	Discontinued	$165 - currently not provided	N/A	N/A	
Discon,/ Recon. At Meter	18 & 19	Continued	$65	$120	Fixed – Average Cost	Maintain Current Rate
Discon./ Recon. At Meter – After Reg. Hrs.	20 & 21	Continued	$185	$320	Fixed – Average Cost	Maintain Current Rate
Discon./ Recon. At Pole	22	Continued	$185	$430	Fixed – Average Cost	
Discon./ Recon. At Pole – After Reg. Hrs.	23	Continued	$415	$850	Fixed – Average Cost	
Meter Dispute Charge	24	Continued	$30	$290 + Meas. Can. Fees	Fixed – Average Cost	

Service Call – Cust Equip	25	Continued	$30	$210	Fixed – Average Cost	
Service Call – Cust Equip After Reg Hrs	26	Continued	$165	$775	Fixed – Average Cost	
Install/ Remove Temp Service	27-29	Continued	Various fixed rates	Actual Incurred Costs	N/A	
Pole Access - Telecom	30	N/A				
Vacant Premise – Move In with Recon. - Meter	31 a)	New	N/A	$95	Fixed – Below Cost	Discontinued
Vacant Premise – Move In with Recon. - Pole	31 b)	New	N/A	$300	Fixed – Average Cost	Discontinued

Recon. – After Reg Hours - Meter	32	New	N/A	$245	Fixed – Average Cost	
Recon. – After Reg Hours - Pole	33	New	N/A	$475	Fixed – Average Cost	
Additional Service Layout	34 & 35	Continued	$635/$845	$561.08	Annual Incr. – Cost Based	
Pipeline/ Water & Railway Crossings	36, 37 & 38	Continued	$2,540 / $3,225 / $6,095	$2,396.75 / $3,522.56 / $4,690.71 + Railway fees	Annual Incr. – Cost Based	
Staking Charges/ Meter (OH, UG and Sub-Cable)	39 a), b) & c)	Continued	$4.95	$4.17 / $3.00 / $2.62	Annual Incr. – Cost Based	
Central Metering – New	40	Continued	$120	$100	Fixed – Actual Cost	
Central Metering – Conv<45 kW, Conv.>45 kW	41 & 42	Continued	$1,035 / $915	$1,534.07 / $1,434.07	Annual Incr. – Cost Based	
Tingle/Stray Voltage Test	43	Discontinued	$140	N/A	N/A	
Standby Admin Charge	44	Discontinued	$520	N/A	N/A	
Connection Impact Assessments	45 a)- f)	Continued	Various – according to project type	Various – according to project type	Annual Incr. – Cost Based	
Retailer Services	46 a) & b)	Continued	Prescribed Handbook Rate	No change	Handbook	
Pole Access	47, 48	Continued	$47.82 /	$76.46 /	Cost Based in	

-LDC/ Generator			$47.82	$76.46	2018 / Escalated at inflation	
Pole Access-Street Light	49	Continued	$2.04	$2.04	By Agreement	
Sentinel Light Rental	50	Continued	$9.51	$10	Fixed. – Cost Based	
Sentinel Light Pole Rental	51	Continued	$4.15	$7	Fixed – Cost Based	
Late Payment	52	Continued	1.5%/month	1.5%/month	Handbook	

In the Original Application, the proposed charges for miscellaneous services were set on one of three bases:

- Based on costs as forecast for each year 2018-2022 and increased annually
- Based on the average forecast costs for the 2018-2022 period and fixed for the period.
- Set at less than costs.

HONI has explained that for a number of the services the charges were based on average costs and fixed for the period in order to avoid customer confusion and to also avoid the additional costs that would be involved if the charges were adjusted annually[131]. HONI has also explained[132] that in the 2006 Handbook there were a group of charges that were previously all set at $15 and for the current Application the charges for these were all set at $13, based on the lowest average calculated cost for this group. This resulted in some of the charges being set below cost. In those instances where the charge was originally set below cost, HONI is no longer proposing to charge for the service as a result of the changes made during the oral proceeding.

As noted above, during the oral proceeding HONI withdrew a number of its proposed specific service charges. At the time, Mr. Boldt testified[133]:

> Hydro One sees no reason why these activities should cease to be part of the standard level of service and proposes to continue to include the costs for these activities in its distribution rates consistent with its past service. This change will result in a shift of about $341,000 from 2018 external revenues to Hydro One's rates' revenue requirement, which will not materially impact Hydro One's customers.

VECC agrees with HONI's proposal to withdraw a number of the specific service charges originally proposed for 2018-2022. However, VECC submits that HONI should also withdraw its proposed charges for Special Meter Reads-Retailer Requested (Rate Code 15). A Special Meter Read charge is applied when a Retailer requests an enrollment / drop prior to the next scheduled read. If an off-cycle meter read is required, Field Staff may be required to perform the off-cycle read if the customer does not have a smart meter or the customer's smart meter isn't communicating[134]. HONI has acknowledged that it is not the customer's "fault" that there is no smart meter or that the smart meter is not communicating[135]. As it is not the customer's responsibility to ensure a functioning smart meter is in place (rather it is HONI's), VECC submits that the customer should not be charged for this service.

[131] Exhibit I, Tab 51, VECC-103
[132] J 10.5-Q33
[133] Volume 11, pages 6-7
[134] Exhibit I, Tab 51, VECC-107
[135] Volume 9, page 178

VECC also supports Hydro One's decision to withdraw the increase to disconnection and reconnection charges proposed in its initial application. Hydro One's rationale, reading between the lines, is that the costs currently indicated in its time study are unlikely to representative of its costs going-forward as it installs remote disconnect meters at more and more premises.

The proposed rate increases, had they been granted, would have created serious affordability issues for consumers who find themselves unable to afford to pay their hydro bills. According to Mr. Merali, the primary drivers for non-payment by residential customers are being unable to afford their hydro bills, or failing to pay one's last bill upon move-out:

> MR. MERALI: So there's a number of factors that underlie bad debt expense, so there's things such as bankruptcies, so businesses frequently go out of business or file for bankruptcy protection, and that would cause us to incur a bad debt expense.
>
> There are also customers who get disconnected for non- pay, which I would say is, you know -- would likely be an affordability issue, who do not ultimately pay their bill. And broadly speaking, a third category would be customers who move out and fail to pay their final bill upon move-out.
>
> MR. SEGEL-BROWN: So I gather -- I'm concerned with residential customers primarily. So I gather from that that the primary causes for residential customers are non-payment, which is usually attributable to affordability or failing to pay the last bill upon move-out.
>
> MR. MERALI: Those would be the primary drivers. There are other smaller drivers, such as a deceased individual and lack of clarity around the estate, but those would be the primary drivers.

Persons who failed to pay their last bill upon move-out cannot be disconnected (as they have already left the address), so the disconnection and reconnection charges will apply primarily to persons who are in arrears because they are unable to afford their bills. These customers are unlikely to be able to afford to pay their arrears, disconnection charge, and reconnection charge in order to resume service, particularly with the proposed increase to those charges. These most vulnerable consumers will be left without power. While there are protections against winter disconnections, those same protections would not apply to, for example, a senior in a potentially fatal summer heatwave.

Moreover, increasing the fees may increase costs for all other consumers. The proposed rate increases are so unaffordable that fewer consumers would be able to reconnect, creating a larger bad debt expense borne by all other ratepayers:

> MR. SEGEL-BROWN: If those costs are incurred by Hydro One but not recovered because the customer never reconnects, who bears those costs?

MR. MERALI: It would ultimately go into bad debt expense, which would be borne by all ratepayers.

Although rates are based on forecasted subscriptions for the rate period, increasing the number of persistently disconnected customers would result in the revenue requirement being split over a slightly smaller number of customers at the next rebasing, which would also increase rates for other customers.

More fundamentally, fees affecting reconnections and vulnerable consumers should not be based on costs alone. Such fees should also be based on a consideration of whether the fees are affordable and consequences if consumers cannot afford to pay the fees. These considerations are linked with the Board's statutory objectives for electricity regulation, including protecting the interests of consumers with respect to prices and promoting economic efficiency in distribution and sale of electricity.

55. Are the proposed line losses over the 2018 – 2022 period appropriate?

For its existing customer classes, HONI proposes to continue to use the Distribution Loss Factors and Total Loss Factors approved by the Board in EB-2013-0416[136]. HONI notes that its historical 5-year average loss factor is consistent with the average loss factor across all customer classes as currently approved by the Board[137].

For the Urban Acquired Customer classes (AR, AUGe and AUGd), HONI proposes that new TLFs be derived by replacing the existing Woodstock Hydro estimated "bulk loss" by the Hydro One "bulk loss". Other components of the TLFs are unchanged from the current Board-approved Woodstock Hydro TLFs[138].

For acquired AR, AGSe and AGSd classes, HONI notes that the new rate classes are comprised of customers from former Norfolk Power and Haldimand County Hydro, which each had different existing Board-approved TLFs. As a result, HONI proposes to use a "kWh weighted average" approach to estimate an average TLF for these new classes. Each individual utility's TLFs were revised by replacing the existing utility's estimated "bulk loss" with the Hydro One "bulk loss". The final TLF for the new classes was then determined by applying the "weighted average" approach to the revised TLFs for each individual distributor[139].

VECC has no issues with HONI's proposed loss factors.

[136136] Exhibit H1, Tab 5, Schedule 1, page 3
[137] Exhibit H1, Tab 5, Schedule 1, pages 7-8
[138] Exhibit H1, Tab 5, Schedule 1, pages 1-2
[139] Exhibit H1, Tab 5, Schedule 1, pages 1-2

56. Do the costs allocated to acquired utilities appropriately reflect the OEB's decisions in related Hydro One acquisition proceedings?

As noted previously, HONI's application included a 2021 cost allocation model which incorporated the customers of the acquired utilities.

In order to be responsive to the Board's direction in its decisions regarding HONI's acquisition of these utilities that future rates for acquired customers be reflective of the costs to serve them, HONI is proposing to create six new customer classes for Residential and General Service customers formerly served by the acquired utilities. In recognition that Woodstock Hydro's customers were mainly located in urban areas, new Acquired Urban Residential, Acquired Urban General Service Energy and Acquired Urban General Service Demand classes are proposed. In contrast, the former Norfolk Power and Haldimand Hydro customers had a mixed density and so three additional new classes – Acquired Residential, Acquired General Service Energy and Acquired General Service Demand- are proposed for these utilities[140]. Former Street Light, Sentinel Light, USL and MicroFit customers of the acquired utilities were "rolled into" HONI's existing customer classes. Similarly, former large GS and Large User customers of these utilities that qualified were rolled into HONI's Sub-Transmission class[141].

In addition, in order to further address the OEB's direction that the rates for acquired customers be reflective of the cost to serve them adjustments were made to the allocation of the gross fixed asset, the net fixed assets and the depreciation in accounts 1815-1860[142] in order to be align the costs in these accounts that are allocated by the CAM to the acquired customer classes to the assets specifically required to serve them[143].

Finally, in terms of the weighting factors for Services and Billing & Collecting, HONI has adopted for the six new customer classes the weights equivalent to those for similar existing customer classes. However, for Meter Capital and Meter Reading the weights reflect the number of meters, the number of manually read meters and the cost per meter for the customer classes concerned[144].

In VECC's view there are two aspects of the Board's past decisions that need to be assessed. The first is whether the proposed changes result in an allocation of costs to the acquired utilities' customers that reflects the cost to serve them. The second is whether or not the overall cost allocated to the acquired utility customers (and which for

[140] Exhibit G1, Tab 2, Schedule 1, pages 6-7
[141] Exhibit G1, Tab 2, Schedule 1, page 5
[142] Exhibit Q, Tab 1, Schedule 1, page 16
[143] Exhibit G!, Tab 3, Schedule 1, page 6
[144] Exhibit I, Tab 46, Schedule VECC-88 and JT 3.18-11

the basis for setting rates) are less than what the customers would have paid if there'd been no acquisitions. This second consideration effectively serves to confirm whether or not the "no-harm" test which HONI contended would be satisfied and on which basis the Board approved the various acquisitions has indeed been met.

1. *HONI's Proposed 2021 Cost Allocation Methodology Adjustment to Accommodate the Acquired Utilities*

1.1 New Customer Classes

With the respect to the proposed new customer classes, the following table set out comparative statistics for the three acquired utilities for 2014 – the last year that all three reported as separate entities.

COMPARATIVE STATISTICS - 2014			
Utility	Cust./km of Line	OM&A/Cust.	Net Fixed Assets/Cust.
Woodstock	63.23	$260.77	$1,804.54
Norfolk	24.66	$368.79	$2,850.02
Haldimand	12.32	$352.62	$2,238.68
Sources: OEB 2014 Yearbook for Electricity Distributors Exhibit I, Tab 46, Schedule VECC-83			

From the table it is clear that Woodstock had a different cost structure than Norfolk or Haldimand and that creating a separate customer classes for the associated acquired customers is appropriate. In the case of Norfolk and Haldimand, the cost structure for Norfolk is higher than that for Haldimand. The differences are roughly 5% when OM&A/customer is considered but over 25% when compared in terms of Net Fixed Assets / customer. As a result, in VECC's view, combining the acquired customers from these two classes will confound the objective of setting rates for the acquired utilities that reflect the cost to serve them.

1.2 Asset and Depreciation Adjustment Factors

However VECC's major concern regarding the cost allocation treatment of the acquired customers is HONI's proposed approach to aligning the asset-related costs allocated to the acquired customer classes with the actual costs to serve those classes. For each of Gross Fixed Assets, Net Fixed Assets and Depreciation, HONI has calculated a single adjustment factor which is applied to the costs allocated to each of the customer classes[145] for each of the Accounts 1815 to 1860. Then, for each account, the difference between the costs allocated to the acquired customer classes per HONI's

145

standard cost allocation methodology and those after the application of the adjustment factors are redistributed (on a proportional basis) to the other customer classes[146].

The issue is that if adjustment factors were to be calculated on an account by account basis the values would be significantly different across the USOA accounts concerned[147]. This means that while HONI's approach results in the correct amount of GFA, NFA and Depreciation being allocated to each of the acquired customer classes, the distribution of the values across USOA accounts will different than if account specific adjustment factors are used. The problem is that the costs in USOA accounts 1815-1860 are not all allocated to customer classes on the same basis. For example the allocation factors for Poles and Fixtures (USOA 1830) is totally difference than the allocation factor for Meters (USOA 1860)[148]. The use of a single adjustment factor for each class for all of the accounts will: i) impact the OM&A associated with these assets that is attributed to each acquired customer class, since OM&A is allocated based on the asset values[149] and ii) impact both the asset values related to these accounts and the related OM&A that is allocated to the balance HONI's customer classes.

During the Technical Conference HONI acknowledged this shortcoming and indicated that it was willing to adopt "account-specific" adjustment factors if the Board determines that to be appropriate. VECC submits that HONI's proposed approach could lead to significant distortions in the cost allocation results and that the Board should direct it to adopt account-specific adjustment factors.

VECC's other major concern regarding HONI's proposed adjustment factors is with regard to its plans for updating the adjustment factors in future applications. In response to interrogatories, HONI indicated that it did not intend to update the adjustment factors unless (at some future date) another acquired utility was harmonized into the acquired customer classes[150]. In the same response, HONI also indicated that after 2021 it would no longer separately track the cost associated with the acquired utilities, as it had done up to 2021 for purposes of determining the adjustment factors. Rather, after harmonization, these classes will share the cost of any future capital programs with HONI's other customer classes[151]. However, during the Technical Conference, HONI only indicated that there would be no need to update the adjustment factors in the near term and that it would assess the need for future updates[152]. During

[146] Exhibit F1, Tab 3 Schedule 1, pages 5-8
[147] Exhibit I, Tab 46, Schedule VECC-90 g)
[148] JT 3.18-13 a)
[149] J 10.5-Q26 a)
[150] Exhibit I, Tab 49, Staff-242 d)
[151] This was also confirmed during the oral proceeding at Volume 10, page118
[152] JT 3.26-3 c)

the oral proceeding, HONI went on to suggest that there would be no need to update the adjustment factors for the next five to ten years[153].

VECC has issues with HONI's plan regarding the future values for adjustment factors. First, by not "tracking" future capital spending and in-service additions related to the acquired utilities' customers, the cost allocated to the acquired customer classes in future cost allocations will not truly reflect the "cost to serve" them. Second, under HONI's proposed approach the adjustment factors applicable to the acquired customer classes will a change any time: i) pre-2021 year end assets identified with the acquired classes are retired, ii) any of the other pre-2021 year end assets in USOA accounts 1815-1860 are retired; or iii) new assets are added to accounts 1815-1860. As result, in VECC's view the adjustment factors will likely change every year. VECC submits that HONI should be required to update it adjustment factors for each future cost allocation. Furthermore, in order to continue to meet the Board's requirement that the rates for the acquired utility customers reflect the costs to serve them HONI will need to continue to track the new in-service additions and retirements of assets required to serve the acquired utilities' customers. Indeed, even future calculations of the adjustment factors based on HONI's proposed approach requires: i) distinguishing between distribution assets install up to versus after 2021 and ii) tracking the retirement of assets installed up to 2021 for purposes of serving the acquired customers.

If HONI is unable or unwilling to meet these requirements then the Board should take this into account when considering future Applications from HONI regarding the acquisition of additional distribution utilities.

2. *Conformance with the No-Harm Test*

In Exhibit Q, Tab 1, Schedule 1, Section 2.2.4 HONI provides a comparison of what its proposed rates are the acquired customer classes versus what the rates would have been had they not been acquired by Hydro One. The results of HONI's analysis shows[154]:

- All residential customers in the new acquired rate classes will see lower distribution charges ranging from -9% to -17%, and lower total bills ranging from -2% to -4%.
- All GS<50 kW customers in the new acquired rate classes will see lower distribution charges ranging from -2% to -30%, and lower total bills ranging from -1% to -9%.
- Norfolk GS>50 kW customers will see a -12% decrease in their distribution charges and a -2% decrease in their total bills.
- Haldimand and Woodstock GS>50 kW customers will see an increase in their distribution charges of +16% and +12%, respectively, but these distribution increases are more than fully offset by Hydro One's proposed reduction to their retail

[153] Volume 10, page 120
[154] Exhibit Q, Tab 1, Schedule 1, page 22

transmission service rates (RTSR), resulting in a decrease in their total bill of -1% and -2%, respectively.

VECC has a number of concerns with HONI's analysis. First, HONI has estimated the rates that the acquired customers would face if there'd been no acquisitions by assuming each utility would have filed either a Price Cap IR or Cost of Service/Rebasing rate application with the OEB annually from when their rates were last approved. For the rebasing applications, HONI assumed that the distribution rates increase by 6.3% which represents the average OEB-approved increase in base distribution rates for the residential and general service <50kW rate classes of all distributors whose rates were rebased in 2015, 2016 and 2017. For the remaining years, the Price Cap IR adjustment is applied based on the actual OEB approved inflation, productivity and stretch factors until 2018, at which point they are held constant[155].

The OEB's Handbook on Transmitter and Distributor Consolidations states[156] that:

> "To demonstrate "no harm", applicants must show that there is a reasonable expectation based on underlying <u>cost structures</u> that the <u>costs</u> to serve acquired customers following a consolidation will be no higher than they otherwise would have been. While the rate implications to all customers will be considered, for an acquisition, the primary consideration will be the expected impact on customers of the acquired utility." (emphasis added)

However, HONI's approach does not result in an estimate of the "costs" the acquired utility customers would fact if there'd been no acquisitions as:

- For the IR adjustment years, the change in rate is based on industry-wide inflation estimates, and
- For the COS years, the adjustment is based on the average rate adjustment experienced by other utilities that rebased over the 2015-2017 period.

This later assumption is particularly problematic as for the Residential class the individual 2015 utility rate increases used range from 0.9% to 14.84%, for 2016 the individual rate increases used ranged from -3% to 25% s and, finally, for 2017 they ranged from -2.32% to 18.78%[157]. Given these ranges is it fair to say that the re-basing rate increase for any utility can vary widely from the 6.3% average and for each of Haldimand, Norfolk and Woodstock this would likely also have been the case.

[155] Exhibit Q, Tab 1, Schedule 1, page 21 and
[156] Page 7
[157] Exhibit Q, Tab 1, Schedule 1 – Attachment 6

During the oral proceeding HONI sought to justify[158] the use of the average utility rate increase by noting that a similar approach is used in setting the rates for Remotes and Algoma. However, VECC would note that in both of these cases the average utility rate increase is not used to establish the overall revenue requirement but rather just the portion of the revenue requirement that will be recovered from rate payers (with the balance of the revenue requirement being recovered through the RRA).

VECC notes that HONI has provided estimates of the 2021 revenue requirement for the acquired utilities assuming no acquisitions (i.e., the status quo) in JT 3.18-19 and the total for 2021 was $36.9 M. During the oral proceeding HONI noted that the depreciation used for 2021 needed to be increased by $2.1 M bringing the estimated revenue requirement for the three acquired utilities to $39 million[159], assuming there'd been no acquisitions.

In contrast, when one looks at the total costs allocated to the acquired utilities customers[160] by HONI's cost allocation model the result is $42.7 million[161].

During the oral proceeding HONI noted that the revenue to cost ratios for the acquired classes were below 100% such that while the classes are allocated $42.7 M they were only being charged $34.9 M and that it is the $34.9 M figure which is relevant to the determination as to whether or not the acquired customers are "better off" vis-à-vis the no harm test[162]. VECC does not agree and submits that the appropriate comparison to determine if HONI's Application produces results that conform with the "no harm" test is to compare: i) the 2021 stand-alone costs that would have existing had there been no acquisitions ($39 M) with ii) the costs allocated to the acquired customers ($42.7 M). Such a comparison is a true "cost" comparison as required by the Board's Handbook. Furthermore, it's the allocated costs that form the basis for the revenue to cost ratios and which are used to benchmark whether or not rates and revenue are appropriate.

Based on this comparison, HONI's cost of serving the acquired customers exceeds what it would have cost on a stand-alone basis, indicating that the cost allocation results do <u>not</u> satisfy the no-harm test. Indeed for the acquired customers to be no worse off the overall revenue to cost ratio for these customers would have to set at well below 100%.

VECC is not contesting the concluded acquisitions and acknowledges that total costs overall are lower as a result of these acquisitions. However, the results of the cost

[158] Volume 10, page 128
[159] Volume 10, page 121
[160] Including acquired customers assigned to HONI's existing customer classes, such as Street Lights and Sentinel.
[161] Exhibit I, Tab 56, Schedule SEC 96 e) ii) – Consists of $41.2 M allocated to the acquired customer classes and $1.5 M associated with the acquired customers assigned to HONI's existing customer classes.
[162] Volume 10, page 123

allocation are such that the acquired customer classes allocated costs exceed the costs they would have borne had the acquisitions not taken place. This is an issue that the Board will need to bear in mind when setting the revenue to cost ratios for the acquired customer classes, both in this Application and in future Applications. In VECC's view it is also important the Board take notice of these results in its consideration of future Applications by HONI to acquire other electricity distribution utilities.

J. DEFERRAL/VARIANCE ACCOUNTS

57. Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

VECC has no issues under this issue.

58. Are the proposed new deferral and variance accounts appropriate?

VECC submissions regarding HONI's proposed new LRAMVA variance account are provide under Issues #46 and #47.

59. Is the proposal to discontinue several deferral and variance accounts appropriate?

VECC has no submissions under this issue.

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