EB-2014-0101

Ontario Energy Board

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

AND IN THE MATTER OF an application by Oshawa PUC Networks for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015 and for each following year through December 31, 2019.

ENERGY PROBE RESEARCH FOUNDATION
("ENERGY PROBE")

SUBMISSION

July 24, 2015

OSHAWA PUC NEWORKS
CUSTOM IR RATES APPLICATION 2015-2019

EB-2014-0101

SUBMISSION OF ENERGY PROBE RESEARCH FOUNDATION

A- INTRODUCTION

Oshawa PUC Networks ("Oshawa" or "OPUCN") filed a Custom IR application with the Ontario Energy Board ("Board" or "OEB") on January 29, 2015.

A Settlement Conference was held on June 2 through June 4, 2015. No issues were settled.

This is the Submission of the Energy Probe Research Foundation ("Energy Probe") related to the issues as set out in the Decision on the Issues List and Procedural Order No. 3 dated June 1, 2015. Please note that there was no Issue 7.6 in the approved issues list.

B - SUBMISSIONS

1.0 CUSTOM APPLICATION

1.1 Is the proposed method for setting rates for 2015 – 2019 appropriate and consistent with OEB policy, particularly with regard to the outcomes approach and objectives described in the RRFE Report?

Energy Probe submits that the answer to the question in this issue is no.

a) Not a Custom IR
Oshawa has filed a five year cost of service application, where a significant amount of the components of the revenue requirement will be updated on an annual basis with what amounts to targeted cost of service updates.

Oshawa acknowledges that their Custom IR plan is in fact a five year cost of service, with annual adjustments. The following three quotes taken from Exhibit 1, Tab C, leave no doubt that this is a cost of service application (emphasis added):

> *"Through this Custom IR proposal OPUCN seeks advance approval of rates that recover the capital expenditures and depreciation expenses incorporated in **OPUCN's forecast cost of service for each of the plan years**." (page 7)*

> *"To meet these objectives, OPUCN has applied for distribution rates for the **test years 2015 through 2019 set on the basis of the detailed cost of service forecasts** and supporting evidence provided in this Application." (page 8)*

> *"**OPUCN's Custom IR Plan proposes that rates will be determined on a cost of service basis for each test year of the plan period**." (page 17)*

In the Hydro One Networks Inc. Decision dated March 12, 2015 (EB-2013-0416/EB-2014-0247) the Board stated:

> *"Hydro One chose to interpret the OEB's Custom IR option, referred to in the RRFE Report as "custom index", to include "custom cost of service". The OEB does not accept this interpretation. All three rate-setting methods are described in the Report as incentive rate-setting, not cost of service."* (page 13)

Energy Probe submits that Oshawa has done the same thing as Hydro One. As a result, the Energy Probe submits that the Board should not approve the application as filed for the same reasons set out in the Hydro Once decision. Simply put, it is not a Custom IR.

Incentive rate making, whether it be a custom IR, 4th generation incentive rate making, or annual IR index, have one thing in common. All three are incentive based rate making mechanisms. A cost of service filing is not an incentive mechanism. The key characteristic of an incentive rate making mechanism is that it decouples the price (rates) that a distributor charges for it services from cost (Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach dated October 18, 2012, page 11 ("RRFE")). This is unchanged from the original Performance Based Regulation ("PBR") approach set out the RP-1999-0034 Decision with Reasons, dated January 18, 2000.

In the Hydro One decision, the Board stated that incentive rate-setting differs from cost of service rate-setting in that it relies less on a utility's internal cost, output, and service quality to establish rates and more on benchmarks of cost, output and service quality that are external to the utility. Hence, the delinking of costs and rates.

Energy Probe submits that the five year cost of service filing from Oshawa fails this very important step. It is not an incentive plan at all, so by definition it cannot be a custom incentive rate-setting plan. In short, it is inconsistent with outcome-based regulation.

Furthermore, Energy Probe submits that the Oshawa plan does not contain adequate efficiency incentives to drive year to year continuous improvement in the company. The Oshawa plan includes embedded annual savings, but this is not equal to productivity and efficiency incentives, as noted by the Board in the Hydro Once decision (page 14). In particular, in that decision, the Board said it was not sufficient to embed savings in cost forecasts. The Board concluded that benefits from explicit and objectively determined productivity and efficiency adjustments such as stretch factors result in sharing anticipated savings with ratepayers up front and facilitate a more outcome based approach to regulation.

Energy Probe agrees with the Board's comments noted above. Energy Probe submits that Oshawa has only embedded savings in their costs forecasts, without any further productivity and efficiency adjustments such as a stretch factor in their bottom up cost of service forecasts.

In addition to the above, Energy Probe submits that Oshawa is a very conservative, risk averse distributor and is not well suited to a Custom IR plan that requires distributors under a Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast. This is discussed in more detail in Issue 1.3.

Oshawa also claims to be a highly efficient distributor. The facts tell a different story.

The evidence is full of references to Oshawa being more efficient than the most other distributors. The Argument-in-Chief repeats this message. In paragraph 58, Oshawa states that it is already a highly efficient distributor and that revenue deficiencies resulting from reduced revenue from slower than forecast growth could not be offset by further efficiencies.

The facts are that in terms of efficiencies, Oshawa is average. Based on the corrected information (see Issue 3.1), Oshawa has been and is currently in the middle cohort as ranked in the benchmarking updates for the stretch factor assignment by group. In fact, Oshawa has been in the middle cohort for ranking purposes since at least 2010.

Oshawa is a low cost distributor, but it is not a highly efficient distributor. Paragraph 70 in the Argument-in-Chief demonstrates that Oshawa believes that low cost is equivalent to high efficiency. Oshawa concludes that because it has the lowest residential rates, is among the lowest net OM&A per customer and the lowest net fixed asset per customer and has the highest customer per FTE ratio then it is already highly efficient.

Energy Probe disagrees. Low cost does not necessarily equate to high efficiency. A perfect example of this is the costs associated with an experienced lineman and an apprentice that is being trained to replace him. An experienced lineman is a higher cost than an apprentice but is likely to be more efficient because of their knowledge and years of experience. The apprentice, while lower cost, is learning and lacks years of experience and is most likely to be less efficient.

b) If Not a Custom IR, Then What?

Given the above submissions, Energy Probe submits that the application does not qualify as a Custom IR. The question then becomes how to set rates for Oshawa. Implicit in the question is whether Oshawa should be placed under a 4th generation IRM plan, or whether the proposed plan can be adjusted or modified to more closely match what the Board expects a Custom IR plan to be under the RRFE.

Energy Probe has had the opportunity to review the submission of Board Staff, dated July 17, 2015. In Section 3.0, titled Options for amending OPUCN's plans to incent efficiency and deliver value to customers, Staff present two options for the Board's consideration. The first of these options is the adoption of the OEB's Price Cap IR framework and the second is a five year Custom IR with one Mid-Term review.

i) Adoption of Price Cap IR Framework

Energy Probe has reviewed the detail submissions of Staff with respect to this option. Energy Probe supports those submissions and adopts them.

Energy Probe submits that given the risk averse nature of Oshawa, it is not well suited for a Custom IR plan that requires it to manage within the rates set, given that actual costs and revenues will vary from forecast and that the variance from forecast is likely to grow over the five year horizon of the plan. Energy Probe submits that Oshawa has not demonstrated its ability to manage under the Custom IR approach.

Energy Probe submits that the incremental or capital module are the proper and better methodology to deal with the highly speculative investments related to the aid to construction for the Enfield TS and for the equally large MS9 station and associated feeders. These two projects have a forecasted cost of $13.5 and $16.0 million respectively. In aggregate, they account for nearly 40% of the total capital expenditures in the 2015 to 2019 period (Appendix 2-AA Updated June 23, 2015). Both of these projects are forecast to come into service in the last two years of the plan. However, there is significant uncertainty with respect to both the timing of these investments and the ultimate cost of these projects. The capital module is designed for precisely these types of projects. Application for a capital module can be made closer to the timing of when these expenditures would take place and the assets placed into service, thus eliminating much of the current uncertainty associated with these projects.

ii) Custom IR with Mid-Term Review

In the response to Undertaking J2.4, Oshawa was asked by Board Staff to comment on the idea of replacing the proposed annual rate adjustment process with one mid-term review that could change rates in 2018 and/or 2019. Oshawa concluded that the proposal had merit and could be implemented by Oshawa with relatively few changes to the essential components of its application as filed.

Energy Probe submits that the mid-term review has merit, however, without the adjustments proposed under Issue 1.2 below, the application would still be a cost of service application for 2015 through 2017, with a potential revision of some of the cost of service revenue requirement components in 2018 and 2019. This would still be a cost of service filing and would not be consistent with a Custom IR plan as noted earlier.

The benefit of a mid-term review is that eliminates, or at least significantly reduces the major unknowns faced by Oshawa at this time, which makes a five year Custom IR or cost of service application problematic. These unknowns include the longer term forecasts, the cost and timing associated with the Enfield TS and the costs and timing associated with the MS9 station and feeders. A mid-term review would address each of these issues.

Energy Probe submits that the following proposal should be considered by the Board. This proposal uses the table found on page 7 of Undertaking J2.4 as the starting point for its proposal.

First, Energy Probe submits that the mid-term review, should take place in 2017 for the determination of any changes to the 2018 and 2019 revenue requirement and should be limited to a discrete number of potential adjustments. These adjustments would be the customer and load forecasts, the contribution costs and timing related to the HONI TS station, the costs and timing related to the MS9 station and associated feeders and third party relocation costs. Oshawa should file the relevant evidence in early 2017, as soon as actual audited information is available for 2016. As part of the filing, complete information should be filed for both 2015 and 2016 on an actual basis, along with the bridge year forecast for 2017 and the forecasts for 2018 and 2019. Even though Energy Probe has submitted that the potential adjustments for 2018 and 2019 should be limited to those noted above, the impact of these changes could be wide reaching. The mid-term review would also be used as a review of 2015 and 2016 as compared to the forecasts approved by the Board.

Second, with respect to the customer and load forecast, Energy Probe submits that the best forecast for 2015, 2016 and 2017 should be maintained. This is the forecast provided in the June 23, 2015 update, reflecting customer growth of 1.5% in 2015 and 3.0% growth in both 2016 and 2017. As Oshawa has indicated in its Argument-in-Chief, this is still their best forecast and is actually lower than the estimated provided by the city, region and developers (Undertaking J2.4, page 5). Oshawa has already indicated that it is willing to live with the forecast risk for any given test year, but cannot accept the risk of the compound forecast error over a five year plan. In this instance, Oshawa would have to live with this forecast risk for one additional year, in 2017. The forecast is one of the potential adjustments available for 2018 and 2019.

Third, there should be an earnings sharing mechanism, as agreed to by Oshawa. More detail on this is provided under Issue 1.2 below.

Fourth, the requested variance accounts for net new connection costs, third party requested plant relocation costs and regional planning costs should be eliminated. Oshawa has agreed that the net new connection costs account could be eliminated if the earnings sharing mechanism is adopted.

Energy Probe submits that the other two accounts can also be eliminated because the regional planning costs (i.e. Enfield TS) and third party relocation costs are potential adjustments that could be made for 2018 and 2019. Living with the current forecasts for these expenditures for the next 2.5 years is not a large risk to Oshawa.

Fifth, the cost of capital would be updated annually in each of the five years to reflect the parameters released by the Board each November, as proposed by Oshawa. This reflects the same approach as the Board approved for Enbridge (EB-2012-0459) and Horizon (EB-2014-0002). As well, if the Board makes any changes in the deemed capital structure, this change would also be implemented as part of the annual update. Oshawa agreed that this would be appropriate (Tr. Vol. 1, page 66).

Sixth, the cost of power component for the purposes of the working capital should be updated annually. However, Energy Probe does not support the use of a trend forecast that has not been the subject of any review in this proceeding, because Oshawa was proposing to update this annually. Energy Probe notes that an updated Regulated Price Plan Price Report is issued each October. Energy Probe submits that the information contained in this report should be used to update the cost of power forecast, along with any known changes to transmission and wholesale rates. This update would coincide with the cost of capital update. This approach would provide a more accurate estimate of the cost of power than using a trend forecast.

Seventh, in addition to the earnings sharing mechanism, adjustments should be made to the plan to incorporate a custom index to calculate OM&A expenses, an efficiency adjustment mechanism and an asymmetrical capital expenditure variance account. Each of these adjustments, and the rationale for them, is described in more detail in Issue 1.2 below.

Eight, adjustments should be made to the capital expenditures, working capital allowance percentage, OM&A forecasts as submitted elsewhere in this argument.

Finally, the two incentive mechanisms proposed by Oshawa should not be approved, but the Board should give consideration to the alternative proposed by Energy Probe. Submissions on the incentive mechanisms are provided under Issue 1.5.

In summary, Energy Probe is proposing an alternative rate plan approach based on a mid-term review that incorporates many of the features approved in the EB-2014-0002 Horizon proceeding that the Board found would satisfy the RRFE's objective that benefits of efficiency improvements would be shared with customers and provide incentives to maintain or improve operational effectiveness. Energy Probe submits that if the Board accepts the application with modifications suggested above and elsewhere in this argument, then a mid-term review as proposed above would be appropriate.

1.2 Does the application adequately incorporate and reflect the four outcomes identified in the RRFE Report: customer focus, operational effectiveness, public policy responsiveness and financial performance?

Energy Probe submits that the answer to the question in this issue is no. However, it is submitted that with the appropriate adjustments, the application can be converted to one that does adequately incorporate and reflect the four outcomes identified in the RRFE report. These adjustments include the removal of some of the components of the plan as filed and include the addition of some components to the plan.

Energy Probe submits that the aspects of the plan proposed by Oshawa that should be removed include, foremost, the majority of the annual adjustments. This is discussed in more detail in Issue 1.3. In addition, the variance accounts around plant relocations and net new customer connections should be removed. These expenditures relate to the normal course of business for a distributor.

Energy Probe submits that the addition of a number of mechanisms would result in the plan satisfying the RRFE's objectives and outcomes.

a) OM&A Adjustments

Energy Probe submits that changing the OM&A forecast from its cost of service basis to a custom index would be in line with the objective to maintain or improve operational effectiveness. This index would be based on an inflation forecast that reflects the makeup of costs for Oshawa, as well as a stretch factor and would be consistent with the Board's approach in the EB-2012-0459 Decision for Enbridge Gas Distribution and the acceptance of the Settlement Proposal in EB-2014-0002 for Horizon Utilities. This mechanism is described in greater detail in Issue 3.1.

b) Earnings Sharing Mechanism

One of the biggest issues and concerns with a Custom IR plan is that there is an inherent bias on the part of the utility to over forecast costs and capital expenditures and under forecast revenues. There is also a concern that intervenors and Board do not have access to the same level of information as does the distributor, creating an uneven playing field.

To address these concerns, Energy Probe submits that the implementation of an Earnings Sharing Mechanism ("ESM") is appropriate. This mechanism provides a safeguard to ratepayers against biased forecasts and meets the Board's objective that efficiency improvements should be shared with customers during the IR term.

Energy Probe submits that the Board should direct Oshawa to implement an asymmetrical earnings sharing mechanism identical to what the Board established for Enbridge in EB-2012-0459 and what it accepted for Horizon (EB-2014-0002). In both cases, the sharing of any earnings over the Board approved return on equity is shared equally with no deadband above the Board approved return on equity.

In the Enbridge decision, the Board acknowledged that the central issue with earnings sharing is that the sharing with ratepayers needs to be balanced with an incentive for the utility to find and retain efficiencies. The Board concluded that an ESM would provide a performance incentive to Enbridge while at the same time ensuring that ratepayers share in the benefits for that performance.

In the Enbridge decision the Board stated that (page 15):

> *"The Board also agrees with CCC that a key consideration is the overall IR framework and the other parameters. The Board is approving a Custom IR for Enbridge, but must address the shortcomings of the plan. The lack of total cost benchmarking and the lack of independent budget assessments result in a greater risk that costs have been over-forecast. Therefore, the Board concludes that*

> *additional ratepayer protection is warranted. A 100 basis point dead band provides insufficient protection for ratepayers, and therefore the Board finds that the dead band should be eliminated for this Custom IR plan. However, the Board is also concerned that there be suitable performance incentives for Enbridge and finds that a sharing ratio of 90:10 in favour of ratepayers largely eliminates the performance incentive for Enbridge. The Board finds that a sharing ratio of 50:50 provides a suitable incentive level for the company while still ensuring significant benefits for ratepayers."*

Energy Probe submits that the same concerns expressed in the Enbridge decision are relevant in the current proceeding. Energy Probe therefore submits that the Board should include an ESM with the same design as it approved for Enbridge and accepted for Horizon.

c) Asymmetric Capital Variance Account(s)

The creation of this account or accounts ensures that ratepayers only pay for projects actually done and done on time. Energy Probe submits that this is an important concept as it eliminates any benefits associated with forecasting higher costs for projects and then coming in under budget. It also protects ratepayers from situations where projects are deferred. Without such an account ratepayers end up paying for projects that are not in service until a later date.

Energy Probe submits that the Board should direct Oshawa to implement this concept which is described in detail, including examples, in the Horizon Utilities EB-2014-0002 Settlement Proposal dated September 22, 2014 at pages 32 through 35, along with Appendix L.

In accepting the same concept included in the Horizon Settlement Proposal, the Board acknowledged that the Capital Expenditure Variance Account satisfied the Board's objective that benefits of efficiency improvements should be shared with customers. Energy Probe submits that the inclusion of the asymmetric account also mitigates over forecasting of capital expenditures and the lack of true benchmarking evidence with respect to capital expenditures. Comments on benchmarking of capital expenditures are provided in Issues 1.5 and 2.2 below.

d) Efficiency Adjustment

Energy Probe submits that the Board should approve an Efficiency Adjustment mechanism that would apply in the event that Oshawa is placed in a less efficient cohort than it is forecast to reside in. Oshawa has indicated that it is currently in the third, or middle cohort of the PEG analysis based on corrected information (Tr. Vol. 1, pages 55-56). Table 2 in the response to Undertaking J2.10 confirms this. Energy Probe submits that the efficiency cohorts, which are updated each year, are a comprehensive measure of utility performance.

Energy Probe further submits that the Efficiency Adjustment should be evaluated as the difference, if any, between the forecasted stretch factor, as shown in Table 2 in Undertaking J2.10 for each of 2015 through 2019 and the actual stretch factor based on the cohort achieved in each of those years times the approved revenue requirement for the year in which there is a difference. This adjustment would be symmetrical in that if Oshawa improved on the forecast cohort, they would be provided with an incentive and if they declined relative to the forecast cohort, ratepayers would receive a refund. This would be accomplished through a variance account that would record the amounts.

It is in the shared interest of both Oshawa and its ratepayers that the distributor maintains or improves their level of efficiency and continues to seek efficiencies in its operations.

Energy Probe notes that this mechanism is similar to that described on page 31 of the September 22, 2014 Settlement Proposal in EB-2014-0002 (Horizon Utilities Custom IR Plan) except that in this proceeding, PEG has provided a forecast of the cohort grouping based on the Oshawa application that can and should be used as the benchmark. Energy Probe further notes that in accepting the Settlement Proposal in the Horizon case, the Board commented that the "efficiency adjustment" concept provided incentives for the distributor to maintain or improve its operational effectiveness and to seek further productivity improvements.

1.3 Are Oshawa PUC’s proposed off-ramps, annual adjustments and adjustments outside the normal course of business appropriate? Are the levels of risk and uncertainty Oshawa proposes to accept and manage appropriate, as distributors under Custom IR are expected to manage variances from forecasts?

a) Off-Ramps

Energy Probe supports the proposed off-ramps, as they are consistent with the RRFE.

b) Annual Adjustments

In the original proposal Oshawa has proposed numerous adjustments on an annual basis. Essentially Oshawa has asked the Board to approve a mechanism where many of the components of the revenue requirement would be updated through a cost of service like update. These updates include customer forecasts, load forecasts, return on equity, cost of debt, capital structure (if there are Board approved changes), capital expenditures related to the HONI contribution, capital expenditures related to relocation projects, capital expenditures related to new customer connection costs including metering, working capital allowance based on the cost of power, depreciation, PILs and anything that qualifies as a Z factor (Tr. Vol. 2, pages 30-32). The only things that would not change are OM&A (under the assumption that OM&A is independent of customer growth), the working capital allowance based on OM&A, other revenues and the remaining capital expenditures. Oshawa further indicated that cost allocation and rate design would not change.

Energy Probe submits that this annual adjustment process would be a significant regulatory burden as it is essentially a cost of service filing for most of the components of the revenue requirement each year.

In addition, Energy Probe submits that the cost allocation and rate design evidence should be updated annually if the Board were to approve the annual adjustments. Changes in the customer and load forecasts, in particular, can have significant impacts on the allocation of costs and on revenue to cost ratios over the five year period. Adjusting these ratios annually would eliminate the potential for significant changes that could be required in the 2020 rebasing application. As the Board is aware, rate impacts resulting from the need to adjust revenue to cost ratios can be as large or even larger than the rate impacts resulting from increases in the revenue requirement.

In summary, Energy Probe submits that the Board should not accept the annual adjustment mechanism as proposed by Oshawa.

c) Adjustments Outside the Normal Course of Business

Energy Probe submits that the only adjustments outside of the normal course of business are associated with the cost and timing of the Enfield TS contribution and the costs and timing associated with the MS9 station and feeders. These are projects that are outside of the normal day to day operations of a distributor, and under 4th generation IRM would undoubtedly qualify for the incremental or advanced capital module treatment. If the Board were to approve the proposed Custom IR as filed, with or without the annual adjustments, Energy Probe submits that there should be variance accounts established for both of these projects around the revenue requirement impact.

If the Board approves a mid-term review, then Energy Probe submits, that in conjunction with an asymmetrical capital variance account, there would be no need for variance accounts around either project. The forecast horizon would be short enough (two years) so that any variance would only exist until 2020 rebasing. The asymmetric variance account would protect ratepayers from slippage in the timing of the projects.

d) Levels of Risk & Uncertainty Managed Under Custom IR

As noted under Issue 1.1, Energy Probe submits that Oshawa is a very conservative, risk averse distributor and is not well suited to a Custom IR plan that requires distributors under such a plan to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast. This inability or unwillingness can be seen in the overall design of the proposed plan and in the specific requests.

The annual adjustments are meant to reduce the risk of the forecasts beyond the next year. As discussed, Oshawa proposed annual adjustments to a host of items included in the revenue requirement, including the customer and load forecast, return on equity, cost of debt, capital structure, capital expenditures related to the aid to construction payable to Hydro One, capital expenditures related to relocation projects, capital expenditures related to net new customer addition costs - including metering, updated working capital allowance based on cost of power changes, depreciation and PILs (Tr. Vol. 2, pages 30-31). In addition to these annual updates there would also be variance accounts around a number of the capital expenditure items.

In the Argument-in-Chief, Oshawa promotes the view that has accepted the risk associated with 85% of its revenue requirement through its proposed plan (paragraphs 40 d, 52 and 64). Energy Probe submits that a distributor should be at risk for 100% of its revenue requirement. Otherwise, the return on equity, or the deemed capital structure, should be adjusted to reflect the reduction of risk to the distributor.

The reduction in the proposed customer and load forecast from 3.0% per year to 1.5% per year in the event that the Board does not allow for annual updates is another example. In the response to Undertaking J2.4, Oshawa states that it continues to believe that the 3.0% forecast is the best forecast, but if it were not able to update its forecast on an annual basis, it says that the risk associated with this forecast is more than it is able to accept.

Being a conservative, risk averse distributor is not meant to be a negative comment about Oshawa and should not be interpreted as such. However, it does point out that Oshawa is not well suited for a Custom IR plan as envisioned by the Board.

As indicated on page 19 of the RRFE, the Board states clearly that it expected a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast. Energy Probe submits that Oshawa has demonstrated the exact opposite. With the myriad of annual adjustments and variance accounts, Oshawa is implicitly indicating that it cannot, or will not, accept these risks. In other words, a true Custom IR does not fit Oshawa.

<u>1.4 Is the monitoring and reporting of performance proposed by Oshawa PUC adequate to demonstrate utility performance over the term of the plan?</u>

<u>a) Current Proposal</u>

Other than the metrics noted below in part (b), Oshawa appears to have a bare minimum of monitoring and reporting of performance limited to some high level RRR numbers that are already provided to the Board and to the projects associated with the CCIEIM.

Energy Probe submits that this level of monitoring and reporting of performance is not adequate to demonstrate utility performance over the term of the plan. For example, there does not appear to be any reporting on capital projects outside of the CCIEIM.

Energy Probe submits that the Board should direct Oshawa to report at each of its annual rate adjustments (whether the annual adjustments are as originally proposed by Oshawa or limited to changes to the cost of capital as proposed under the mid-term review option) on the actual results for the previous year and provide variance analyses to the Board approved figures. This is the only way that the Board and parties will be able to evaluate utility performance over the term of the plan.

<u>b) Metrics</u>

Oshawa has proposed two metrics for monitoring and reporting purposes. The first is maintaining the current reported performance on each of the OEB scorecard metrics and the second is maintaining OEB service quality requirements at least at the level achieved in 2014 (Undertaking J1.3, pages 3-5). No consequences of failing to meet these targets have been proposed.

Energy Probe notes that Oshawa did introduce one metric during the oral portion of the hearing that it proposed to track. This metric dealt with the equipment failure - porcelain insulator equipment and foreign interference - animal contact, as described in the response to Undertaking J1.3. The target set was 62, which is higher than the results recorded in 2014.

In addition most of the expenditures in these categories had been completed by the end of 2014 and that only about $1 million was forecast to be spent over the 2015 to 2019 period to complete the projects (Tr. Vol. 3, pages 95-101). In addition there were no consequences proposed if Oshawa failed to meet its target.

Energy Probe submits that the above metric is not useful in monitoring the effectiveness of the capital expenditure program given that it represents about 1.3% of the capital expenditures forecast for the 2015 through 2019 period and the majority of the capital expenditures made to improve this metric were already completed by the end of the 2014 year.

c) Future Metrics

Oshawa was receptive to the concept that, if the Board came up with metrics and targets through an industry-wide consultation during the term of Oshawa's IR plan, it would insert them into its program for the remainder of the time left in the plan (Tr. Vol. 2, pages 22-23). Energy Probe submits that the Board should adopt this approach.

1.5 Are the two proposed incentive mechanisms necessary and / or appropriate? Has the benefit to ratepayers of the incentive mechanisms been adequately demonstrated?

Oshawa has proposed two incentive mechanisms - the Total Cost Efficiency Carryover Mechanism ("TCECM") and the Controllable Capital Investment Efficiency Incentive Mechanism ("CCIEIM"). Energy Probe submits that the Board should not approve either of these incentive mechanisms.

a) Total Cost Efficiency Carryover Mechanism

The TCECM is described in Exhibit 10, Tab C, pages 12 through 14 and this description has not been repeated here. However, as indicated in the response to part (b) of Interrogatory 10-Staff-50, Oshawa has modified its proposal to eliminate the effect of weather on the return on equity, to eliminate the effect of weather on the TCECM. The response to Undertaking J1.4 provides the methodology proposed by Oshawa to accomplish this weather normalization of the return on equity. Oshawa also proposed accepting responsibility for demonstrating efficiencies which are sustainable beyond the current term of the IR plan in order to be eligible for the incentive payment in 2020 and 2021 (Exhibit K1.2).

In the response to Undertaking J2.4, as part of the mid-term review option, Oshawa proposes to modify the TCECM to apply only to the last two years (2018 and 2019) and the plan would still include weather normalization and the onus would still be on Oshawa to demonstrate sustainable efficiencies in years 2018 and 2019 in order to qualify for an incentive reward in 2020 and 2021.

The concept of the TCECM is to provide an incentive for continued efficiency improvements especially near the end of the IR plan period. Energy Probe submits that the plan is flawed, as is the normalization methodology proposed.

Using the return on equity as the proxy by which to measure efficiency ignores the fact that the return on equity is heavily influenced by events that are completely unrelated to efficiency improvements. While Oshawa has agreed that normalizing out the impact of weather should be considered, Energy Probe submits that there are numerous other impacts that affect the return on equity that have nothing to do with efficiency improvements. This list is numerous, but would include such things as changes in tax rates, capital cost allowance rates, tax credits, economic conditions, the gain (or expansions) or loss (or contraction) of a major customer or customers, variances from forecast of customer additions, changes in volumes from forecast for non-weather factors such as CDM reductions and economic factors and changes from forecast of OM&A costs and capital expenditures.

An increase in the number of customer attachments from that forecast, or in higher volumes due to lower than forecast CDM reductions or better economic conditions (i.e. a lower than forecast unemployment rate), an expansion at a large customer and reductions in tax rates or increases in CCA deductions would all result in a higher return on equity. Similarly, lower OM&A costs that are the result of one or more individuals being on long term disability (as has happened at Oshawa in 2014) or lower capital expenditures because of the deferral of some expenditures would also result in a higher return on equity. Each of these items could also result in a lower return on equity in the reverse situation.

Included in the above, the return on equity would increase if there were efficiencies that were implemented, but were not sustainable. This could include having longer than planned for vacancies in some years or deferring the purchase of a bucket truck by a year or two.

In none of these cases, does the resulting change in the return on equity have anything to do with efficiency improvements. In fact, it is quite possible that the return on equity could be higher than the Board approved figure without any efficiency improvements. Similarly, efficiency improvements could take place but the return on equity would be lower than the Board approved figure due to these other items.

For this reason Energy Probe submits that the Board should not approve the TCECM as proposed by Oshawa.

Board Staff put forward a proposal that would base the TCECM on a productivity metric. As indicated in the response to Undertaking J2.6, Oshawa states that it would appear that this proposal would suffer from the same weaknesses as the return on equity approach. Energy Probe agrees with Oshawa and further submits that the proposal has not been the subject of full discovery and review in this proceeding.

Energy Probe submits that there is another possibility for an efficiency carry over mechanism. This mechanism would continue to require Oshawa to accept responsibility for demonstrating efficiencies which are sustainable beyond the current rate term (2015 - 2019) and that were implemented in 2018 and 2019. Similar to the Oshawa proposal in Undertaking J2.4 noted above, the efficiency carry over mechanism would be based on results for 2018 and 2019 only.

The mechanism would be based on the stretch factor assignments that are produced each year for the Board.

As shown in Table 2 in the response to Undertaking J2.10, PEG has estimated that Oshawa's stretch factor will be 0.15%, meaning they would be in the second best group of the five.

Energy Probe submits that the Board should approved a TCECM that uses this forecast, which is based on the Oshawa forecasts as the baseline to compare the actual stretch factor assignment for 2018 and 2019 on an actual basis. If, on an actual basis, Oshawa is able achieve a lower average stretch factor for 2018 and 2019 then it would be eligible for the incentive, subject to the demonstration of sustainable efficiencies. However, if in 2018 and 2019 the actual average stretch factor achieved is higher than the forecast, Oshawa would have to pay an incentive to ratepayers, who were promised a more efficient utility by the end of the IR plan term. In other words, the proposed TCECM would be symmetrical.

The incentive/penalty would be calculated in a manner similar to that proposed by Oshawa and would be capped at 0.50% of the deemed equity. However, Energy Probe submits that the deemed equity to which the incentive/penalty would apply would be based on the 2019 deemed equity.

As an example, if Oshawa achieved Group 2 status in 2018 and Group 1 status in 2019, it would be eligible for an incentive equal to 0.50% of $57.75 million (June 23, 2015 updated RRWF) or about $290,000. Oshawa would have to demonstrate that there are sustainable efficiencies introduced in 2018 and/or 2019 that would exceed this amount. If they did not, the incentive would be reduced to the amount of the sustainable efficiencies. Similarly, if Oshawa achieved Group 2 status in 2018, but fell to Group 3 status in 2019, it would have to pay a penalty of $290,000 to its ratepayers for failing to deliver on the sustainable efficiencies.

A third outcome would be that on average Oshawa had a stretch factor of 0.15%, as forecast. This could be the result of maintaining Group 2 status in both 2018 and 2019 or slipping to Group 3 in 2018 (0.30%) and improving to Group 1 status in 2019 (0.00%), or vice-versa. In each case, because the average did not exceed or fall below the forecasted level, there would be no incentive or payment.

Energy Probe submits that this is a simpler mechanism to implement and track than either the Oshawa proposal or the Board Staff proposal, while maintaining an incentive to achieve sustainable efficiencies in the last two years of the plan. In fact, by adding the potential for a penalty, there is more incentive for the distributor to find efficiencies to avoid a potential penalty.

Finally, Energy Probe is making some submissions with respect to the normalization methodology proposed by Oshawa if the Board were to accept their proposal for the TCECM to be based on return on equity.

The proposed methodology was provided in the response to Undertaking J1.4 and was discussed in the oral hearing (Tr. Vol. 2, pages 187-188). Energy Probe submits that there are several issues with the proposal. First, the "normalization" is in fact, the difference between two sets of forecasts where the only difference between the forecasts is between actual heating and cooling degree days and the forecasted heating and cooling degree days. As Mr. Martin acknowledged both of these figures are totally independent of the actual volumes, which is what should be normalized.

The methodology then calculates a ratio based on the two forecasts. Energy Probe submits that this is not appropriate, as the volume difference can be estimated on an absolute basis which would be more accurate than the use of a ratio.

Further, the methodology does not indicate how the change in volumes would be allocated to the various rate classes. This needs to be done because the revenue impact will be different for each rate class because the volumetric rates are different by rate class. While Mr. Martin agreed that there should be no adjustment to rate classes that are determined not to be weather sensitive, he did not have a proposal on how to allocate the volumetric difference to the weather sensitive classes.

Finally, Oshawa agreed that the cost of power would also change due to the volumetric change and that would have an impact on the rate base through the working capital allowance. However, they did not consider how this would be reflected in the normalized return on equity.

Energy Probe submits that if the return on equity is the basis for the TCECM, it should not be normalized at this time. As discussed earlier, the return on equity will be influenced by a host of non sustainable efficiency factors. Adding weather to that list would not be significant. Energy Probe notes that there is no evidence on the magnitude of the change in revenues, rate base and the return on equity of weather. Unlike gas distributors where the weather can have a significant impact on sales, electricity distributors are much more insulated from weather impacts given the lack of heating load in a utility like Oshawa where all customers have access to natural gas and the fact that, unlike gas distributors, electricity distributors have two distinct degree day seasons where one often offsets the impact of the other (e.g. a warmer than normal winter results in reduced volumes, while a warmer than normal summer increases volumes).

If the Board believes that the return on equity should be normalized, then Energy Probe submits that it should direct Oshawa to bring forward a methodology for review at its next annual adjustment proceeding.

<u>b) Controllable Capital Investment Efficiency Incentive Mechanism</u>

The CCIEIM is described in Exhibit 10, Tab C, pages 14 through 19 and has description has not been repeated here. However, it should be noted that the two major capital investment programs - system renewal and MS9 substation and associated distribution feeders - have had significant changes in the dollar amounts attributed to them. In particular, the system renewal program has been revised from $19.75 million to $23.899 million and the MS9 related expenditures have increased from $9 million to $16.0 million. Both of these revised figures are provided in Table 1 in the response to Undertaking J2.3.

The concept of the CCIEIM is to reward the utility for accomplishing its individual capital projects included in the two programs at a cost lower than forecast or to penalize it for spending more than forecast. While great in theory, Energy Probe submits that there are several practical issues that make the value of the CCIEIM questionable.

The first issue is the lack of benchmarking associated with the baseline cost forecasts for the individual projects included in the programs that are proposed to be included in the CCIEIM. As discussed under Issue 2.2 below, the benchmarking that Oshawa has relied on with respect to its capital expenditures in aggregate is not, in the submissions of

Energy Probe, relevant. The third party benchmarking of the projects did not take into consideration the labour rates, material rates, capitalization policies and cost structure of Oshawa. Moreover, the third party benchmarking, which was done prior to the filing of the application, could not have taken into account the significant increase in costs from $9 million to $16 million related to the MS9 substation and associated feeders that took play in May, 2015 in and update to the evidence. This project was significantly changed as a result of the change in the regional plan to the Enfield TS solution (TC Tr. Vol. 1, pages 124-127).

The second issue, also addressed more fully under Issue 2.2 below is that Oshawa plans do to better than their forecast. With regards to the capital expenditures, Mr. Labricciosa stated that "*...but through the incentive aspect of it, we are suggesting that, you know, internally how we manage the company,* ***<u>we are going to set a target for ourselves to manage it better than those estimates</u>****."* (TC Tr. Vol. 1, page 26, emphasis added) In other words, Oshawa has two sets of forecasts, one used to set the target for the CCIEIM and one for internal purposes which is a lower cost.

The third issue revolves around the incentive/penalty provisions. The Oshawa proposal is that it would receive and incentive equal to 50% of the revenue requirement associated with the avoided rate base over the duration of the average duration of the capital items included in the CCIEIM.

Energy Probe submits that asking ratepayers to pay for investments made in assets used to serve them is one thing. Asking ratepayers to pay for investments NOT made in assets is quite another thing. Energy Probe submits that a distributor has an obligation, not only to ratepayers, but also to its shareholder, to ensure that it does not pay more for an asset than it should. To do so would be imprudent and would reflect badly on management. On top of that, the proposal is that Oshawa would claw back 50% of the savings over the life of the investment from ratepayers.

Similarly, Energy Probe has reservations about only including 50% of the incremental costs if costs are in excess of the forecast. If the costs were incurred prudently, Energy Probe does not believe the Board should remove 50% of those prudently incurred costs from rate base. The utility is allowed to earn a return on its investment so the enforcement of this provision could be challenged and even if it were ultimately upheld as being appropriate, the utility will still incur costs (financing and depreciation) on those assets removed from rate base. This could affect the cost of future financing as well as increase regulatory and accounting costs as these costs would need to be tracked separately for the life of the assets.

Thirdly, the proposal leads to the prospect of potential gaming. As part of the proposal, Oshawa has indicated that if a project is deferred or is not completed by the end of the five year IR plan period, it would be removed from the CCIEIM for evaluation purposes. Energy Probe submits that this is reasonable, since you cannot compare the actual cost to the forecast cost of a project that has not been completed. However, this leads to a potential situation in which a utility may re-prioritize the CCIEIM projects to do the ones it believes now come in under budget before it does the ones that it believes may now come in over budget, rather than remaining with the prioritization from the distribution system plan. It may also encourage a utility to defer the completion of a project to beyond the end of 2019 if the project cost is tracking above forecast.

Fourth, Oshawa has proposed that any project where there has been a material change in scope, would be removed from the CCIEIM. Energy Probe submits that it would be very difficult to evaluate what was a "material" change after the fact.

Fifth, the CCIEIM is proposed to be calculated only at the end of the five year plan, and not on an annual basis. This leads to the potential situation where the projects could be deferred from the earlier years but completed by the end of the five year period at a cost lower than forecast, resulting in the incentive payment to Oshawa and the corresponding additional cost to ratepayers beyond 2020. At the same time this would mean that the ratepayers paid higher rates in the early years of the IR plan when the investments were not made. In other words, ratepayers would pay twice. Once in 2015 to 2019 rates that were too high based on when the actual expenditures were made and again beyond 2020 in order to provide the incentive to Oshawa.

Energy Probe notes that this last issue would be mitigated if the Board approved an asymmetric capital variance account, as proposed by Energy Probe under Issue 1.2 above.

In summary, Energy Probe submits that the CCIEIM is not necessary and could result in perverse and inappropriate results. However, if the Board sees merit in proceeding with the CCIEIM, or some modified version thereof, Energy Probe submits that it should only proceed with the system renewal program and not the MS9 related program. This is because of the significant change in the MS9 program from that originally filed and the final forecast provided in the updates, which lacked any benchmarking.

Energy Probe also submits that if the Board adopts the CCIEIM for the system renewal projects it should also adopt an asymmetric capital variance account around the system renewal costs included in the CCIEIM to project ratepayers from the adverse consequences of timing changes in the projects, which the CCIEIM does not address.

2.0 DISTRIBUTION SYSTEM PLAN AND CAPITAL EXPENDITURES

2.1 Is the Distribution System Plan adequate to demonstrate Oshawa PUC's planning rationale and customer responsiveness?

Energy Probe submits that the Distribution System Plan ("DSP") is adequate to demonstrate Oshawa's planning rationale and customer responsiveness at a high level. However, the Oshawa plan only locks in about two-thirds of the forecasted capital expenditures over the 2015 to 2019 period.

In the response to Undertaking J2.1, Oshawa provided the line items in Appendix 2-AA that were not proposed to be adjusted during the IR term and would not be subject to variance account treatment during the plan. Appendix 2-AA from the June 23, 2015 update was included in Exhibit 1.4 on page 22. Capital expenditures for the 2015 through 2019 period total approximately $75 million. The line items included in Undertaking J2.1 total about $50 million over this period. This leaves a significant amount of capital expenditures that would either be updated as part of the proposal annual adjustment, or covered by a variance account. In either case, Energy Probe submits that this brings into question the validity and usefulness of the DSP. If Oshawa can change its forecast on a year to year basis, what is the value of a 5 year DSP?

This is especially evident in the system access portion of the table. Of the nearly $14 million in expenditures in this category only about 10% are locked in. The capital expenditures (and contributions) associated with relocations and system expansions would be updated on an annual basis. Energy Probe submits that this is not appropriate given that relocations and system expansion are part of the normal day to day operation of the utility. On the other hand, updates associated with the contribution payable to Hydro One Networks Inc. are more palatable because this does not represent a project that is part of the normal day to day operation of the utility.

In any event, it appears to Energy Probe that the DSP will not be a document to which comparisons can be made on annual basis going forward because significant parts of the plan may be adjusted on an annual basis.

If the Board were to approve the mid-term review concept as put forward by Oshawa in Undertaking J2.4, then it appears to Energy Probe that the DSP becomes more relevant in that the current forecasts would be maintained for all five years of the Custom IR plan horizon. The only exception would be a possible change in the net new connection costs for 2018 and 2019 based on an updated customer connection forecast for those two years.

Even if the DSP is adequate at a high level in indentifying areas for expenditures to be made over the 5 year period, Energy Probe notes that this does not imply that the level of expenditures forecast by Oshawa are appropriate. This is dealt with in the following issue.

2.2 Is the level of planned capital expenditures for 2015 – 2019 appropriate, and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:
• customer feedback and preferences;
• productivity;
• benchmarking of costs;
• reliability and service quality;
• impact on distribution rates;
• trade-offs with OM&A spending; and
• government-mandated obligations.

Energy Probe submits that the planned capital expenditures are not appropriate. This submission is based on a number of issues with the forecast.

First, Oshawa has a history of under spending on capital as compared to their plan. This is clearly demonstrated in their planned and actual spending in 2012 through 2014 period, beginning with their last cost of service rebasing period for 2012. As shown in Exhibit 2, Tab A, page 7, in the last cost of service rebasing application, Oshawa indicated spending plans for the 2011 through 2015 period. In 2012 through 2014 the planned capital expenditures totaled about $36.6 million. A review of Appendix 2-AA included at page 22 of Exhibit K1.4 shows that the actual level of capital expenditures over this period was about $32.5 million. In other words, over this three year period, actual spending was less than 90% of the planned expenditures.

In the response to 2-GOCC-3, Oshawa attributed the under spending to a number of factors including detailed design phase identified savings, negotiated savings with its external suppliers, improved project management during construction and commissioning phases and changes in project requirements either in scope, scale or timing.

Oshawa has not included the impacts of any of these factors in its forecast for 2015 through 2019. Mr. Labricciosa was clear that the forecasts included in the evidence were estimates based on where Oshawa was at today and that there was no stretch factor built into the capital forecast (TC Tr. Vol. 1, page 26). The forecast of capital expenditures is a typical bottom-up approach used in a cost of service application. Oshawa states that it has applied for distribution rates for the test years 2015 through 2019 to be set on the basis of the detailed cost of service forecasts provided in the application (Exhibit 1, Tab C, page 8).

Second, Oshawa has not provided any relevant benchmarking with regards to the cost of the capital projects. Oshawa did provide evidence from third parties that indicated the cost forecasts of Oshawa were lower than their high level estimate of the costs. However, it was clear that this third party review was based on their own assumptions rather than the relevant information specific to Oshawa such as the distributor's labour rates, material rates, capitalization policies and cost structure (Tr. Vol. 1, pages 96-99).

Throughout this proceeding Oshawa has emphasized that it is a low cost distributor and based on that there is an expectation that the costs would be lower than an average utility. The Oshawa witnesses stated that they started with their own design and budget based on their own costs and that their costs were lower than the benchmark prepared by the third party firm. They also did not see any benefit in providing the third party with Oshawa's cost structure, equipment costs, design, etc., because they would end up coming up with the same estimate as Oshawa. Energy Probe submits that this would not necessarily be the outcome. The benchmarking exercise could come up with a different design. After all, Mr. Mahajan indicated that this was how Oshawa reduced the level of capital expenditures in the past:

> *"We have a manager of -- or a supervisor of design who was going to feed Oshawa Centre, a huge shopping mall in the middle of Oshawa, a design that was approved by multiple parties, but he identified opportunities to do that capital investment differently, which resulted in savings on capital expenditure."* (Tr. Vol. 1, pages 18-19)

The benchmarking exercise could also come up with a plan that included less hours of labour and/or required as a result of optimization of construction practices.

Third, Oshawa actually has internal targets to manage their capital expenditures better than the estimates that are included in the evidence. In particular, Mr. Labricciosa said that *"When you say "embedded in your costs", our estimates are based on where we are at today. And so the stretch factor, we didn't actually put a target number there, but through the incentive aspect of it, we are suggesting that, you know, internally how we manage the company,* ***we are going to set a target for ourselves to manage it better than those estimates****."* (TC Tr. Vol. 1, page 26, emphasis added)

In other words, the forecasts that Oshawa is asking the Board to approve are figures that they plan on beating. Oshawa has its own internal benchmarking which suggests that they can come in under forecast. The net result is that ratepayers end up paying for capital additions that do not take place.

Oshawa has not forecast any new efficiency or productivity measures that would result in lower capital expenditures than that forecast for the 2015 through 2019 period despite highlighting the factors that they say drove the lower than planned expenditures in 2012 through 2014. They have not provided any relevant benchmarking which the Board could rely on to conclude that their capital expenditure costs are reasonable.

Energy Probe submits that the Board should reduce the level of capital expenditures by 10% in each of 2015 through 2019 to reflect the under spending in the 2012 through 2014 period and the fact that Oshawa has not included any efficiency or productivity measures in the forecast period, despite indicating that this was a driver of the lower capital expenditures in the previous years.

However, if the Board approved the asymmetric capital variance account as proposed by Energy Probe earlier in this submission, then Energy Probe submits that the importance of the capital expenditure forecast would be reduced. The asymmetric variance account would eliminate any impact of forecasting higher costs than what the utility actually believed it would spend. It would continue to act as an incentive to not go over budget, while providing a safeguard to ratepayers.

2.3 Is the proposed 2015 rate base reasonable?

Energy Probe has submitted that it believes the capital expenditures for all years are inflated and that Oshawa has indicated that it has targeted to do better than the forecasts. As such Energy Probe submits that the Board should, in the absence of an asymmetrical variance account, reduce the capital expenditures in 2015 by 10% to reflect the over forecast/under spending in the previous years.

If the Board were to approve the asymmetrical capital variance account, then Energy Probe would accept the 2015 forecast as filed, with one exception which is dealt with under Issue 2.4 below.

Energy Probe further notes that Oshawa has indicated in its Argument in that it found an error with respect to the new Depreciation Expense Deferral Account (Exhibit 1, Tab C, pages 41-42). That evidence indicated that the proposed 2015 rate base had been reduced to reflect the higher depreciation expense over the 2012 through 2014 period that resulted from the independent depreciation study that was undertaken. However, as noted on page 40 of the Argument-in-Chief, this had not been done and that Oshawa would make this correction to the 2015 and forward rate base in its Draft Rate Order to be filed following the Board's decision. Energy Probe supports this proposal and submits that the Board should direct Oshawa to do so.

2.4 Are the proposed timing of additions to rate base appropriate?

Energy Probe has three issues with the proposed timing of additions to rate base.

The first issue is that the capital additions to rate base are front loaded to 2015 and 2016 over the five year forecast horizon when the capital contributions to HONI and the MS9 station costs are removed.

Both of these projects represent significant one-time costs ($13.5 million for HONI and $14.5 million for MS9). When they are removed, the capital additions total about $12.8 million in 2015 and $10.2 million in 2016 before falling to an average of about $8.3 million in 2017 through 2019. These figures are found on page 9 of Exhibit K1.3. Energy Probe submits that these capital additions should be averaged over the five year period as a rate mitigation strategy. Averaged over five years, the annual capital additions would be about $9.6 million per year.

The second issue Energy Probe has with the timing of the capital expenditures relates to the HONI contribution and the MS9 related costs; the Oshawa evidence on the timing and cost of both of these projects is speculative at best.

While Oshawa has requested a variance account to capture the revenue requirement impact of the difference between forecast and actual costs associated with the contribution to HONI (Exhibit 1, Tab B, page 3), there is no such variance account requested for the MS9 station and related feeder costs (Tr. Vol. 2, page 31). In fact, Oshawa is not proposing to update the cost or timing associated with this project, which totals $16.0 million (Tr. Vol. 3, pages 24-25).

However, the timing of the expenditures related to the MS9 project are dependent on the construction of the Enfield TS by HONI. As indicated by Mr. Labricciosa, as a result of the updated regional plan, the timing of the MS9 station and feeders changed from that filed in the original evidence in which portions of the MS9 costs would be added to rate base in each year from 2015 to 2019 to the updated forecast in which the station is added in 2018 and the feeders are added in 2018 and 2019. Mr. Labricciosa described this change in the technical conference:

> *"So ideally we were going to bring parts of MS9, a small part of the station, not build the entire thing, but just put enough or new connections and not a lot of load. And so some of those pieces were coming in-service, because you could add one transformer, one set of switchgear and one feeder, and eventually continue to add the second transformer, the second set of switchgear and other feeders as capacity came on stream.*
>
> *Now, because it's almost all upfront, Enfield has to be built, then the two additional feeders to connect -- the two new feeders to connect MS9, and MS9 gets built and in service basically at the back end and all at once.*
>
> *There is no sense incrementalizing it along the way."* (TC Tr. Vol. 1, page 125).

The second paragraph in the above quote clearly indicates that the MS9 related expenditures and inclusion in rate base will occur after Enfield has been built. Oshawa has forecast that the Enfield TS will be in service in 2018, but indicated they were not sure it would be in service in 2018:

> *"MR. RUBENSTEIN: All right. And while the Enfield TS station spreads out over numerous years, am I correct, the capital contributions, there is really only one project, and that is -- for the one transformer station for the Enfield station, correct? And that is supposed to go in service in 2018, correct? While you're paying the capital contributions, you expect multiple years?*
>
> *MR. MARTIN: Yes, we're not sure it is in-service in 2018. That is subject to Hydro One's completion.*
>
> *Are we talking MS9 or are we talking Hydro One?*
>
> *MR. RUBENSTEIN: We're talking about the Enfield TS.*
> *MR. MARTIN: Hydro One. Our prediction is 2018.*
> *MR. MAHAJAN: Yes.*
> *MR. MARTIN: Yes."* (Tr. Vol. 1, pages 34-35)

Energy Probe submits there is no evidence to support an in-service date of 2018 for Enfield TS and therefore no evidence to support an in-service date of 2018 and 2019 for the MS9 station and feeders. However, these major capital expenditures could be updated in terms of both cost and timing as part of a mid-term review in 2017 for the 2018 and 2019 test years.

The third issue Energy Probe has is with the addition to rate base of $1.350 million in 2015, $5.4 million in 2017 and $6.75 million in 2018 for contributions payable to HONI for the Enfield TS. As noted above, this asset is not scheduled to go into service until at least 2018 (Tr. Vol. 1, page 34). However, Oshawa has placed the above noted contribution payments in service in 2015 and 2017.

Energy Probe submits that because the asset is not forecast to be in service before 2018, none of the contributions should be placed into rates prior to this period. Rather the contribution should be placed in work-in-progress. This is no different than if the payments were being made to a third party that was constructing the asset or if the amounts were paid for materials and labour for internal Oshawa costs. In all cases, the expenditures would go into work-in-progress until the asset is placed in service. The Enfield TS is neither used nor useful until it is commissioned and placed into service.

2.5 Has the working capital allowance been appropriately determined through the Lead-Lag study?

Oshawa originally filed for a working capital allowance ("WCA") of 13%, based on the lead/lag study filed in Exhibit 2, Tab A, Schedule 1. This study was filed by Ernst & Young ("E&Y"). However, it was collaboration between E&Y and Oshawa (Tr. Vol. 1, page 107) in terms of concepts, calculations and methodologies used in the study. None of the authors of the study had previously completed a lead/lag study for a regulated electricity or natural gas distributor in North America (Tr. Vol. 1, pages 107-108).

As part of the June 23, 2015 update (Exhibit K1.2), Oshawa updated the WCA calculation to reflect a number of corrections and changes that resulted from the interrogatory process and through the technical conference. These changes, which Energy Probe submits are appropriate and should be accepted by the Board, are found in the table on page 2 of the attachment to June 23, 2015 update. These changes resulted in a reduction of the WCA percentage from 13.0% to 10.9%.

As part of the undertaking responses, Oshawa filed Exhibit K4.1 that showed the updated revenue requirements as a result of three further corrections and changes to the evidence. One of these changes was an increase in the cost of power expense lead from 20.89 to 24.64 days. This update was provided in the response to Undertaking J1.1 and reflected a more accurate calculation of the actual expense lead in 2013 associated with the payments made for the cost of power, including margin calls. The figure of 24.64 days was calculated in the top table provided on page 12 of Exhibit K1.4. E&Y agreed that this calculation was a more accurate calculation of the cost of power expense lead than the calculation that was used in the E&Y report (Tr. Vol. 1, pages 115-119). This change further reduces the WCA percentage from 10.9% to 10.02% (Tr. Vol. 4, page 3).

Energy Probe submits that the 24.64 days is a more accurate estimation of the cost of power expense lead and should be adopted by the Board if it ultimately finds that the use of margin calls by Oshawa is in the best interest of Oshawa's ratepayers. Energy Probe makes further submissions on the use of margin calls and the impact on ratepayers below in part (b).

Energy Probe is making submissions on two further areas that it believes require adjustment in the calculation of the WCA percentage. These two areas are the calculation of the service lag and the calculation of the cost of power expense lead in the absence of margin calls.

<u>a) Service Lag</u>

The E&Y report defines the service lag as the "weighted average days gap from when service is provided to the customer to the date when the meter read is taken showing consumption" (Exhibit 2, Tab A, Schedule 1, page 6). Page 7 of the same documents states that the *"Service lag for electricity distribution is the amount of time from when service is provided to customers to the date the meter read is performed."*

Further, the E&Y report states, at the bottom of page 5 that *"When the start date and end date are unknown, the service is evenly distributed over the duration of the service period. For calculation purposes, Mid-point =([Service Period in days])/2."*

Mr. Stepanuik agreed that the midpoint of the service period over which service is provided is from immediately after a meter reading to the next meter reading and that based on the E&Y methodology noted above in the previous paragraph the calculated results in the 15.2 days (Tr. Vol. 1, pages 130-131). When asked about the other lead/lag studies that were reviewed and whether anybody who billed all of its customers monthly, as Oshawa does, used something other than 15.2 days as a service lag, Mr. Stepanuik stated that no, everyone typically used the 15.21 figure (Tr. Vol. 1, page 132).

However, Mr. Martin, on behalf of Oshawa did not agree that the service lag is the midpoint of the service period (Tr. Vol. 1, page 132) in the case of Oshawa. He then went on to say that if that was the case then the unbilled revenue would be approximately equal to the billed revenue in any given month. Energy Probe strong disagrees.

As demonstrated in the cross examination, the methodology used by E&Y/Oshawa of calculating the ratio of the average unbilled revenue to the average billed revenue at the end of the month, multiplying by 365 and dividing by 12 and then dividing by 2 to get the midpoint is independent of the service lag, which is meter read to meter read. The methodology employed by E&Y/Oshawa is dependent not on when the meters are read, but on how quickly after the meter is read, the bill is produced (Tr. Vol. 1, pages 125-130). This is entirely based on the billing lag, which has been estimated as 17 days and is accepted by Energy Probe.

It was demonstrated that changing the billing lag would result in a change in the calculation. For example, a shorter billing lag would reduce unbilled revenue and increase billed revenue at month end, resulting in a lower ratio that would result in a lower service lag. Similarly, Mr. Stepanuik stated that Oshawa was *"providing **more service** than the 15.2 would be calculating, we've had to modify that by using that calculation method to give us a **bigger service period** because we're actually **having more service, if you will, being provided** than what would typically be being billed"* (emphasis added, Tr. Vol. 1, page 128).

Energy Probe submits that the above response clearly demonstrates a misunderstanding on the part of E&Y and Oshawa of the service lag as compared to the billing lag. The service lag is based solely on how often the meter is read and is the midpoint of the period between meter reads. It is not impacted by when an invoice is completed. The billing lag is the lag that is impacted by the time between the meter read and the invoice date.

A simple two customer example illustrates this point. Consider a distributor that has two customers that are billed on a monthly basis on the same day each month. One customer has their meter read on January 14, and with a 17 day billing lag, the invoice is issued January 31 for an amount of $100. The second customer has their meter read on January 15, and with the same 17 day billing lag, the invoice is issued on February 1 for $1,000. Based on the E&Y/Oshawa methodology, the unbilled revenue at the end of January is $1,000 and the billed revenue is $100, resulting in a ratio of 10 and a service lag of more than 152 days (1000/100 x 365 / 12 / 2)! Further, if the meter reading dates of these two customers is reversed, the unbilled revenue now becomes $100 at the end of the month and the billed revenue becomes $1,000, resulting in a service lag calculation based on the E&Y/Oshawa methodology of 1.52 days. Clearly this significant change in the calculation of the service lag is not reasonable given the almost insignificant change that resulted in the change.

The real service lag in the above simple example, has not changed. Each customer has a service period from one monthly meter read to the following meter read. With monthly billing in place, the service lag is immutable.

Energy Probe notes that the difference in the definition of the service lag is the root cause of the difference in the methodology used to calculate the service lag. Mr. Martin indicated that in his view *"The calculation here is the service lag, not the service period. And those two aren't -- those two aren't synonymous."* (TC Tr. Vol. 1, page 158). Mr. Martin then went on to state that he also believed that this was E&Y's view, even though he indicated that this industry is unique with respect to the service lag and that Oshawa *"had to educate E&Y to a certain extent on how the service lag -- how the unbilled component works"* (TC Tr. Vol.1, page 158).

While Energy Probe notes that the service lag and the service period are not synonymous, there is a direct link. The service lag is the midpoint of the service period. E&Y agreed with this in both their evidence and in their oral testimony (Tr. Vol. 1, pages 130-131).

Energy Probe also submits that the two customer example throws significant doubt that the calculation provides a reasonable estimate of the billing lag and should not be used as such. Oshawa has already estimated its billing lag based on a process review that was based on the availability of spot rate information provided by the IESO (Exhibit B, Tab A, Schedule 1, page 8) and the amount of time it takes Oshawa's third party billing provider (TC Tr. Vol. 1, page 156).

Energy Probe further notes that the 15.22 days is the standard shown in Appendix A to the Board's letter of June 3, 2015 Re: Allowance for Working Capital for Electricity Distribution Rate Applications. This was included at pages 1 through 6 of Exhibit K1.4. Indeed, the calculation shown in Appendix A reflects the midpoint calculation supported by the E&Y report.

Energy Probe estimates that the impact of replacing the service lag of 17.44 days with the proper industry standard figure of 15.22 days reduces the WCA percentage from 10.02% to approximately 9.37%.

<u>b) Cost of Power Expense Lead and Cost of Margin Calls</u>

As noted above, based on the use of margin calls, the cost of power expense lag has been calculated to be 24.64 days. Energy Probe supports this figure, but only if the Board determines that the continued use of margin calls by Oshawa is in the best interest of the ratepayers.

On the other hand, if the Board determines that there is a **<u>material benefit</u>** to ratepayers of ceasing the use of margin calls - or at least significantly reducing their use - then Energy Probe submits that the cost of power expense lead should be increased from 24.64 days to 32.91 days. The calculation of this figure is explained in the following paragraphs. The issue of a material benefit for ratepayers is then addressed in the final section.

i) COP Expense Lead of 32.91 Days

The cost of power expense lead in the absence of the use of margin calls can be directly calculated based on the evidence provided in this proceeding.

In the response to TC Undertaking 1.9, Oshawa provided the due dates and amounts for the monthly invoices for the cost of power for the 2013 calendar year. This is the year that Oshawa has based its WCA percentage calculation on in its June 23, 2015 update (Exhibit K1.2) and the further updated provided in Exhibit K4.1. Energy Probe accepts that using the most recent year for which an analysis has been completed is appropriate.

The table provided below shows the calculation of the weighted average cost of power expense based on the information provided in the above noted undertaking.

COST OF POWER EXPENSE LEAD CALCULATION

Month Ending	Invoice Total	Date Paid (Final Amount)	Days From End of Month
31-Jan-13	$11,685,026	19-Feb-13	19
28-Feb-13	$8,833,674	18-Mar-13	18
31-Mar-13	$9,287,110	17-Apr-13	17
30-Apr-13	$8,869,964	16-May-13	16
31-May-13	$7,675,317	18-Jun-13	18
30-Jun-13	$9,262,497	17-Jul-13	17
31-Jul-13	$12,813,031	19-Aug-13	19
31-Aug-13	$9,084,700	18-Sep-13	18
30-Sep-13	$9,549,261	17-Oct-13	17
31-Oct-13	$8,028,606	19-Nov-13	19
30-Nov-13	$9,948,720	17-Dec-13	17
31-Dec-13	$14,282,560	17-Jan-14	17
Total	$119,320,467	$ Weighted Avg Days	17.69
		Service Lag	15.22
		Cost of Power Lag	32.91

As the information in the table demonstrates, the dollar weighted average days after the end of the service month in which the power was provided is 17.69 days based on the dates that Oshawa paid the final amounts due each month. These are the dates that Oshawa would have paid the full invoice each month had they not used margin calls.

The service period for the cost of power is by definition the calendar month since the IESO bills distributors at the end of each month for the power consumed in that month.

Therefore, by definition, given the service lead of 15.22 days (i.e. the midpoint of the average month) to the end of the month and adding this to the payment lag of 17.69 days from the end of the service month, the net result in a cost of power expense lead of 32.91 days. In other words, in the absence of margin calls, Oshawa would have paid its cost of power bills, on average, 32.91 days after the deemed receipt of the power.

Energy Probe notes that this is very similar to the figure of 32.7 days calculated in Appendix A of the Board's letter of June 3, 2015 Re: Allowance for Working Capital for Electricity Distribution Rate Applications which indicates that the lead times shown in the appendix are the median figures based on observed results for each expense element of the lead/lag studies reviewed by the Board. In other words, in the absence of the margin calls, the Oshawa figure is not materially different than the median found in other lead/lag studies reviewed by the Board.

ii) Material Benefit to Ratepayers

Oshawa is well within its rights to use margin calls to pay the IESO. However, one of the key aspects of the RRFE is the emphasis on ratepayers.

In particular, the RRFE states that customer focus and operational effectiveness are outcomes that are appropriate for the distributors. Customer focus is identified as services being provided in a manner that responds to identified customer preferences. Operational effectiveness relates to the achievement of continuous improvement in productivity and in cost performance.

Energy Probe notes that in every customer survey that it has seen, rates are among the highest, if not the highest, issue identified by ratepayers. Clearly affordable rates are front and center with respect to customer preferences.

Energy Probe submits that the continued use of margin calls results in higher costs to ratepayers than is necessary, violating both the above mentioned outcomes and is not responsive to customer preferences for low rates.

Energy Probe submits that ratepayers would be **materially** better off in the absence of margin calls or in a significant reduction in their use.

As can be seen in the response to TC Undertaking 1.9, Oshawa had a total of 46 margin calls in 2012 and 33 in 2013. This is an average of nearly 2.5 margin calls per month. Energy Probe submits that this is a significant number of transactions to be monitored, initiated and tracked on a monthly basis by Oshawa, undoubtedly resulting in some employees having less time to do their other work, thereby impacting on productivity.

As explained by Mr. Martin, Oshawa has a $7.5 million line of credit that it uses as a prudential support for the IESO and that this letter of credit has an annual cost of about $50,000 (Tr. Vol. 1, pages 122-123).

Mr. Martin further indicated that Oshawa would need a letter of credit in the range of $10 to $12 million to eliminate the margin calls and that the annual incremental cost of higher letter of credit would be in the neighbourhood of $50,000 (Tr. Vol. 1, pages 123-124).

Energy Probe submits that the question for the Board is a simple one. Would ratepayers be better off paying an additional $50,000 for a higher letter of credit that would eliminate the need for margin calls. Energy Probe submits that the clear and unambiguous answer is yes.

The following table shows the estimated impact on the revenue requirement of a one percentage point change in the WCA for Oshawa, based on their corrected cost of long term debt (Exhibit K4.1) and the RRWF for 2015 filed as part of the June 23, 2015 update (Exhibit K1.2).

Revenue Requirement Impact of a 1% Change in WCA - 2015

	Capital Structure	After-Tax Return	Pre-Tax Return
Long Term Debt	56.00%	4.24%	4.24%
Short Term Debt	4.00%	2.16%	2.16%
Equity (1)	40.00%	9.30%	12.65%
Total		6.18%	7.52%
(1) Pre-Tax Return based on tax rate of 26.5%			
Controllable Expenses & Cost of Power			133,050,000
One Percentage Point Change in Working Capital Rate			1.00%
Impact on Working Capital Allowance Component of Rate Base			1,330,500
Pre-Tax Return			7.52%
Impact on Ratepayers			100,081

As the above table illustrates, the impact on the 2015 revenue requirement paid by ratepayers of a 1 percent point change in the WCA percentage is approximately $100,000. Of course this figure will grow as the controllable expenses (OM&A and cost of power) increase in future years.

Energy Probe estimates that by increasing the cost of power expense lead from 24.64 days to the 32.91 days calculated in part (b) (i) above based on actual payment dates for 2013, the WCA would decline from 9.37% as calculated in part (a) above to 7.33% as shown in the following table.

WORKING CAPITAL ALLOWANCE

(reflecting corrected Service Lag and Cost of Power Expense Lead with higher Letter of Credit)

Revenue Lag		
Service Lag		15.22
Billing Lag		17.00
Collection Lag		21.46
Paym Proc. Lag		1.50
		55.18
Distribution	97.85%	53.99
Other (-24.29 days)	2.15%	-0.52
		53.47

WCA Calculation	Revenue Lag	Inventory Lag	Expense Lead	Net Lag	WC Factor	Expenses	WC Requirement
Cost of Power	53.47		32.91	20.56	5.63%	102,012,056	5,747,004
OM&A - payroll	53.47		10.63	42.84	11.74%	5,667,950	665,290
OM&A - supplier	53.47	50.88	17.75	86.60	23.73%	5,389,853	1,278,840
OM&A - mun. Tax	53.47		(16.50)	69.97	19.17%	152,292	29,195
Interest	53.47		12.40	41.07	11.25%	1,910,000	214,929
PILS	53.47		12.50	40.97	11.23%	240,000	26,941
Debt retirement	53.47		30.50	22.97	6.29%	7,532,929	474,117
Sub-Total						122,905,080	8,436,316
HST						1,446,444	(126,495)
Total						124,351,524	8,309,821
Working Capital Allowance							**7.33%**

As the above table illustrates, the reduction in the WCA percentage would be from 9.37% to 7.33% as a result of increasing the letter of credit. This decline is more than 2 full percentage points and when combined with the $100,000 impact of a 1 percentage point change in the WCA calculated earlier, results in a reduction to ratepayers of approximately $200,000 per year. When partially offset by the increase in cost of the higher letter of credit of $50,000 per year, the net benefit to ratepayers is $150,000 per year, or three quarters of a million dollars over the term of the Custom IR period. The materiality threshold used by Oshawa is $100,000 (Exhibit 1, Tab F, page 1). Clearly the net benefits to ratepayers are **material**.

Energy Probe submits that by increasing the letter of credit so as to eliminate the need for margin calls provides a **material benefit** to ratepayers of approximately $150,000 in 2015 and that this benefit will grow in future years as the controllable expenses to which the WCA applies grows.

If Oshawa continues to use margin calls because of the limited line of credit of $7.5 million, then Energy Probe submits that Oshawa will have failed to meet key outcomes associated with the RRFE. First, it will have failed with regards to Customer Focus because it will not have passed on material savings to ratepayers when one of the key customer preferences is lower rates. Second, it will have failed with regards to Operational Effectiveness because it will have failed to pass on the net savings to customers by changing the way that it pays the IESO.

In both circumstances, Energy Probe submits that the Board should direct Oshawa to incorporate a higher cost for the letter of credit and the reduction in the revenue requirement as a result of the reduction in the WCA so that the net material savings to ratepayers of approximately $150,000 per year are reflected in rates.

c) Summary of Proposed Changes

In summary, Energy Probe submits that the Board should approve a WCA percentage of 7.33% for Oshawa. This reflects the numerous corrections that Oshawa has agreed to through the interrogatory, undertaking and cross examination processes. It also reflects a correct figure for the service lag (15.22 days) and the cost of power expense lead that reflects a higher letter of credit (32.91 days), which is a **material benefit** to ratepayers This conforms with the intent of the RRFE related to customer focus and operational effectiveness.

3.0 OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

3.1 Is the level of planned OM&A expenditures for 2015 – 2019 appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to:

• customer feedback and preferences;
• productivity;
• benchmarking of costs;
• reliability and service quality;
• impact on distribution rates;
• trade-offs with capital spending; and
• government-mandated obligations.

Energy Probe submits that the OM&A forecast for each of 2015 through 2019 is too high and that it is not consistent with the Custom IR plan because it is based on a bottom up cost of service methodology for each of the years. This is discussed above in more detail under Issue 1.3.

Energy Probe submits that the OM&A costs should be based on the drivers that affect OM&A. In general, these include inflation, productivity growth and customer growth. Under an "incentive" IR plan, Energy Probe submits that they should also include a stretch factor. In other words, Energy Probe submits that custom index should be applied to a distributor that reflects their individual mix of OM&A between labour and non-labour costs, the forecast of customer growth and their specific stretch factor based on the efficiency cohort in which they are placed or forecast to be placed.

This approach is consistent with the Board's Decision in EB-2012-0459 for Enbridge Gas Distribution. Enbridge requested a 2.24% annual increase in its OM&A costs (excluding those costs included under the Regulatory Cost Allocation Methodology ("RCAM") that deal with the corporate allocation of costs from its parent company, which were determined through a consultative). Enbridge indicated that it had determined the OM&A budget using a bottom-up approach to understand the business needs and a top-down approach to embed productivity. This appears to be what Oshawa has done as well. It has done a bottom-up approach through the cost of service methodology used for each year, along with embedding productivity in the figures. In this case, unlike Enbridge, Oshawa did not make any top-down adjustments, based on its belief that it had already built productivity improvements into the bottom-up approach.

In its Decision with Reasons dated July 17, 2014, the Board found (page 45) that it *"will make an adjustment to the 5-year Other O&M budget so that it recognizes inflation, incremental cost pressures, and customer growth, but also an adequate level of productivity improvement. This adjustment is necessary to incent Enbridge to greater efficiency and to protect the interests of ratepayers over the term of the Custom IR plan."*

In the Horizon Settlement Proposal (EB-2014-0002) dated September 22, 2014, the parties agreed to an increase in the first year of the Custom IR plan that reflected specific requirements identified by Horizon to add resources. Many of these resources were deferred over the previous IR plan term because of the loss of revenues from a large customer. Subsequent years OM&A expenses are then to be calculated based on an escalation factor of 1.47% that factored in forecast inflation, customer growth, productivity and a stretch factor. In accepting the Settlement Proposal, the Board stated (page 3) that it found that there were several features in the Settlement Proposal that satisfy the RRFE's objective that benefits of efficiency improvements would be shared with customers. The Board explicitly stated that one of these features was the proposed reduction in Horizon's submitted Operating, Maintenance and Administration (OMA) that would provide incentives for Horizon to maintain or improve its operational effectiveness and to see further productivity improvements.

Energy Probe submits that Board should adopt the same approach for Oshawa as it did for both Enbridge and Horizon.

In Appendix A-1 to this argument, Energy Probe has provided the calculations that it believes reflects this approach and incorporates a custom index based on inflation rates, customer growth and stretch factors that are specific to Oshawa.

Section 1 in Appendix A-1 shows the calculation of an adjusted actual and forecast level of OM&A (line 10). Historically, the costs removed are one-time costs that need to be removed to arrive at an appropriate historical OM&A level. These adjustments are the 2012 ice storm costs (a one-time event) and some charitable donations, which are not recoverable from ratepayers.

One additional reduction has been made. This is a $50,000 reduction in the historical and forecast years for the letter of credit used as a prudential support for the payments made to the IESO. Energy Probe has a further submission on this at the end of this issue.

The second part of Section 1in Appendix A-1 shows the calculation of the weighted inflation rate for Oshawa. The labour and non-labour shares are based on the information provided in the response to 4-Energy Probe-42. The inflation rates used are those used by the Board for labour increases (Average Weekly Earnings: Statistics Canada, Table 281-0027) and non-labour increases (GDP-IPI-FDD: Statistics Canada, Table 380-0066). The values for 2012 through 2014 reflect actual data; the value for 2015 has been taken from the Board`s website for 2015 electricity distribution rate applications; the value for 2016 has been set equal to the 2014 actual data from Statistics Canada, since this is how the 2016 inflation factors will be set; the value for 2017 through 2019 have been set equal to the 2016 forecast. This is all noted in footnote (2) in Section 1 of the appendix.

Section 2 of Appendix A-1 then calculates the escalators applicable to Oshawa. In addition to the weighted inflation rate (line 24), adjustments are made for base productivity (line 25), the stretch factor (line 26) and customer growth (line 27). Each of these additional adjustments is explained as follows.

The base productivity numbers reflect the figures used by the Board in the third generation IRM (0.72% for 2012 and 2013) and 0% used in the fourth generation IRM for the 2014 and future years.

The stretch factor reflects the cohorts that Oshawa was in historically and currently and the forecasted cohort group in the future. Specifically, in 2012 and 2013, Oshawa was in the second of the three cohort groups and this middle cohort was assigned a stretch factor of 0.4%. In 2014 and 2015, Oshawa has been placed in the third of the five groups, with a stretch factor of 0.30%. This is based on a correction that was identified (Tr. Vol. 1, pages 55-56). It has been forecast that Oshawa will remain in this group with the associated stretch factor of 0.30% in 2016 and 2017, before improving to the second cohort group with an associated stretch factor of 0.15%. This forecast is shown in Table 2 of the response from Undertaking J2.10 from Pacific Economics Group and is consistent with their original evidence in this proceeding, as filed in Exhibit 10, Tab A.

The impact of customer growth, which is shown in Section 4 of Appendix A-1, is reflected in line 27. In this appendix, the impact of customer growth in the historical years of 2012 through 2014 is calculated using the 0.44 factor estimated by PEG that a 1% change in customers results in a 0.44% change in OM&A for the average company (Exhibit 4, page 8).

For 2015 through 2019, Energy Probe has used a factor of 0.00, which is consistent with Oshawa`s evidence that over the Custom IR period, the customer growth has no, or at most an immaterial, impact on the OM&A (Tr. Vol. 2, pages 166-167). Mr. Martin explained that about 70%of the OM&A costs revolve around employees and assuming there is some customer growth, there is no room in the plan to reduce the number of FTEs. Mr. Martin reinforced this in the following exchange (Tr. Vol. 3, pages 13-14):

> *"MR. AIKEN: Yesterday, there was a lot of discussion about the relationship between customer growth and OM&A costs, and whether that relationship was the .44 factor as calculated by PEG, or the .11 factor used by PowerStream, or some other factor.*
>
> *As I understand your evidence, however, there is no relationship between customer growth and OM&A costs in the 2015 to 2019 test year period. Am I interpreting your evidence appropriately?*
>
> *[Witness panel confers]*
>
> *MR. MARTIN: Sorry, so there is -- there is a -- certainly in building our forecast we took into account the growth, but there isn't any -- there isn't any material expenses associated with that growth on the OM&A side, and other*

than meter and connection costs there wouldn't be any direct connection on the capital side or any other material amount."

Section 3 of Appendix A-1 then calculates the OM&A using the escalators calculated in Section 2, using three different starting points, actual adjusted OM&A for each of 2012, 2013 and 2014. Using this approach and then averaging out the resulting forecast ensures that no one year is used as the basis, since any given year may have anomalies in the actual expenditures.

As an example, on line 34, the 2015 forecast of $11,511,872 is derived by starting with the 2012 actual figure of $11,005,290 and increasing by the Oshawa specific escalators for 2013, 2014 and 2015 found on line 28, of 0.90%, 2.37% and 1.28%, respectively. The 2016 forecast is the same calculation except that an additional escalator of 1.76% for 2016 is used, and so on.

Based on the average of all three years used as starting points in the analysis, the 2015 OM&A figure is $11,282,436, which is a reduction of $721,409 from the adjusted forecast. This represents an increase of 2.48% from the previous year actual expenditure. Similarly, reductions for each of 2016 through 2019 are shown online 38.

Energy Probe submits that this approach is consistent with a Custom IR plan and is consistent with the approach taken in both the Enbridge and Horizon proceedings. It reflects the external factors driving the increase, such as inflation, while maintaining a focus on operational effectiveness, a key outcome in the RRFE.

However, if the Board is concerned with Oshawa's evidence that its OM&A expenses are not impacted by customer growth, then Energy Probe submits that the Board should also take into account the estimate of base productivity for Ontario distributors found in Table 2 of Undertaking J2.10. In particular, PEG has estimated a level of Ontario OM&A productivity growth (Column B in Table 2) of 0.31%. This reflects the adoption of IFRS by a number of LDCs.

Energy Probe has provided the same calculations as in Appendix A-2 as it did in Appendix A-1 with two changes. First the base productivity factor (line 25) has been changed from 0.00 in 2014 through 2019 to 0.31 in each of those years, consistent with the response to Undertaking J2.10. Second, the customer growth component of the escalator (line 27) reflects use of the 0.44 factor in each of 2015 through 2019, replacing the 0.00 factor used in Appendix A-1.

Finally, Energy Probe is making a submission on the inclusion of the interest cost associated with the prudential letter of credit in OM&A expenses. Energy Probe submits that this should not be recorded in OM&A, but is rather a short term debt expense. This expense is covered off by the cost of capital, which is based on a deemed capital structure and rates for return on equity, long term debt and short term debt.

Mr. Martin agreed that there is a cost of capital associated with tying up these funds (Tr. Vol. 1, pages 123-124). Energy Probe submits that Oshawa is already being compensated for these funds through both the working capital allowance component of rate base that deals with cash flow requirements caused by the cost of power. In other words, the cost of financing the cash flow associated with paying the IESO is included in rate base. It should not also be included in OM&A. That amounts to double counting.

In addition to the letter of credit, Oshawa has an operating line of credit $10 million that is also used to assist with working capital requirements (Tr. Vol. 1, page 123). The cost of this operating line of credit is recovered through the deemed capital structure and the associated rates for the components of the capital structure. There are no costs associated with this included in OM&A, as it is already included in rate base through the working capital allowance. Energy Probe sees no difference between this treatment and the way the costs associated with the letter of credit should be treated. Both are rate based; neither should be expensed.

4.0 FORECASTS

4.1 Are the customer and load forecasts a reasonable reflection of the energy and demand requirements of the applicant for 2015 – 2019?

Energy Probe submits that both the customer and load forecast provided in the June 23, 2015 update (Exhibit K1.2) are appropriate and should be accepted by the Board.

The updated load forecast reflected changes in the forecast customer additions, an updated regression model and forecast based on updated unemployment data from the Conference Board of Canada, revised CDM reflecting the delay in the City of Oshawa's plans to retrofit streetlights with LED bulbs and corrected CDM forecasts for 2019 savings from programs implemented in 2013.

Energy Probe submits that these adjustments to the load forecast (kWh and kW) are appropriate and should be accepted by the Board.

The most significant change made by Oshawa in the June update was the reduction in the customer addition forecast, reducing it from 3.0% to 1.5% in 2015. The update of 1.5% reflects actual experience in January through May of 2015. While Oshawa did not change the customer forecast of 3.0% in each of the subsequent years, the absolute value of the number of customers forecast for all years is lower due to the reduction in 2015.

Oshawa has proposed that the customer and load forecast be adjusted on an annual basis. Energy Probe has dealt with this proposal under Issue 1.3 above.

Oshawa has further proposed that if the Board does not allow annual adjustments, or adopts a mid-term review plan, the load forecast should be reduced to 1.5% for all years. Energy Probe strongly disagrees.

In the response to Undertaking J2.4 (page 6), Oshawa states that if the Board were not to accept their proposal for the annual update, the risk posed by the "best" growth forecast of 3% is more significant than it able to accept. Energy Probe submits that this is a function of the extremely risk averse nature of Oshawa, discussed under Issue 1.1 above.

The evidence in this proceeding is clear. The 3% customer addition forecast, and the associated impact on the load forecast is the best forecast provided by Oshawa. Oshawa confirmed on numerous occasions that the 3% customer forecast remained their best forecast of growth in 2016 through 2019 (Tr. Vol. 2 pages 100-101 & page 127, Argument In Chief, paragraph 132).

Furthermore, this incremental customer addition growth forecast over and above historical trends has been provided in the evidence, by rate class by year and is driven by the Distribution System Plan (Exhibit 3, pages 25-27). In fact, Oshawa states that one of the key drivers in its increased capital expenditures is customer growth (Exhibit 1, Tab C, page 5 and page 28) impacting both system expansion and system reinforcement projects and expenditures. At page 28, one of the three key drivers for the capital expenditures over IR plan term was *"Customer connections increasing by approximately 3% per year on average compared with historical averages of approximately 1%."*

The forecast was also confirmed as being accurate in the responses to Interrogatories 3-Staff-18 and 3-Staff-19.

The clearest indication that the 3% customer growth is the best forecast comes in the response to Undertaking J2.4:

> *"OPUCN continues to believe that a 3% annual forecast growth rate is the "best" forecast for its expected circumstances, given: i) data from the City, the Region and local developers that indicates that hoped for growth in Oshawa during the rate plan term is greater than 3% (and closer to 4%); ii)*

an historical (including 2015 year to date) growth trend that is closer to 1.5%; and iii) the tremendous amount of infrastructure work and economic activity required in the next 4.5 years for the City, the Region and local developers to realize their growth aspirations." (page 5)

Energy Probe also notes that the growth in customers has been accelerating since at least 2012. As shown in the June 23, 2015 updated version of Appendix 2-L, the increase in the number of customers has grown from 0.6% in 2012, to 1.0% in 2013, to 1.4% in 2014 and to 1.5% on a year-to-date May basis for 2015. Clearly the trend is towards higher growth.

As noted earlier in this submission, Energy Probe submits that the Board should accept a 3% customer addition forecast and the corresponding load forecast for both 2016 and 2017 if the Board determines that a mid-term review is appropriate. The forecasts for 2018 and 2019 would be part of that mid-term review.

4.2 Are the proposed other operating revenues for 2015 – 2019 appropriate?

Energy Probe has no issues with the other operating revenue forecast for 2015 as updated in June, 2015. Energy Probe further notes that Oshawa has corrected the other operating revenue forecast for 2016 to 2019 in the response to Undertaking J3.3. This correction was a result of the discussion between Mr. Savage and Mr. Aiken (Tr. Vol. 2, pages 194-196).

Energy Probe submits that the Board should accept this forecast, which is partially based on customer growth of 1.5% in 2015 and 3.0% in each of the following years.

If the Board were to adjust the customer forecast in any of the years, then it is submitted that the other operating revenue should also be adjusted to reflect the changes that would be driven by the higher or lower customer forecast, based on the methodology used by Oshawa to adjust some of the components of the other operating revenue.

5.0 REVENUE REQUIREMENT

5.1 Have all elements of the Base Revenue Requirements for 2015 – 2019 been determined accurately and in accordance with Board policies and practices?

Energy Probe has made submissions with respect to the level and timing of capital expenditures and the resulting net property, plant and equipment component of rate base under Issues 2.1 through 2.4 above. Submissions with respect to the working capital allowance component of rate base have been included under Issue 2.5 above. Submissions with respect to OM&A have been included under Issue 3.1 above.

Energy Probe is providing submissions with respect to the remainder of the components of the revenue requirement under this issue. These components includes the capital structure and cost of capital, depreciation and PILs.

<u>a) Capital Structure and Cost of Capital</u>
Energy Probe has identified three issues related to the capital structure and cost of capital which require submissions.

The first issue relates to the proposed annual update of the cost of capital (both long term and short term debt and return on equity). Energy Probe submits that these adjustments are appropriate and notes that they are consistent with the Custom IR decisions for Horizon Utilities (EB-2014-0002), Enbridge Gas Distribution (EB-2012-0459) and Hydro One Networks (EB2013-0416/EB-2014-0247). Energy Probe notes that the Hydro One Networks decision did not approve the application as a Custom IR, but put in place an adjustment mechanism for the cost of capital over the three year duration of the plan.

Energy Probe further submits that the capital structure should also be adjusted if, at some time during the next 5 years, the Board makes changes to the deemed capital structure through a generic review of the cost of capital. As the Board moves to recovering a greater share of the revenue requirement through fixed charges, the risk to distributors is being reduced, most notably with respect to the weather risk. This reduction in risk may well result in a change in the deemed capital structure at the next cost of capital review.

Oshawa indicated that its proposal for annual updates to the cost of capital would also include changes to the Board's deemed capital structure (Tr. Vol. 1, page 66). Energy Probe submits that if the Board approves an annual update for the cost of capital parameters it should also approve an update for the capital structure which also impacts the overall cost of capital.

The second issue is the error in the calculation of the long term debt rate of 4.24% for 2015. This error was discussed during cross examination (Tr. Vol. 2, pages 197-198) and was focused on the new debt issue of $15 million that took place in June of 2015. In the response to Undertaking J2.12, Oshawa corrected the calculation for this debt instrument and the resulting long term debt rate for 2015 has been reduced to 4.11%. Energy Probe supports this correction and submits that the 4.11% is the correct figure for 2015.

The third and final issue related to the cost of capital is directly related to the forecasted cost of new long term debt to be issued over the plan horizon. As part of the annual updated proposed by Oshawa, the long term debt rate would reflect any actual new debt issues along with the actual rates associated with those issues and the affiliate debt would reflect the Board's deemed long term debt rate as set each November. Energy Probe submits that this is appropriate. However, in the circumstance where Oshawa is forecasting new long term debt for the current or test year where it has not entered into an agreement, Oshawa proposes using the then current Board deemed long term debt rate. Energy Probe submits that the Board should reject this part of the proposal.

The onus remains on the utility to provide a forecast not only for the amount of additional long term debt but also the appropriate rate to be applied to it. The distributor should have to justify the need for additional debt and it is expected they would do so. However, Oshawa is proposing that the rate would automatically default to the Board's deemed rate. Energy Probe submits that this is not appropriate.

As seen in this proceeding, Oshawa initially proposed to use the Board's current deemed long term debt rate of 4.77% for the debt it had not yet entered into, but forecast that it would in 2015. In the June 23 update (Exhibit K1.2) Oshawa revealed that it had entered into a long term loan agreement for $15 million for a term of 7 years at a rate of 2.71%, more than 200 basis points below the Board's deemed rate. Energy Probe submits that this is clear evidence that Oshawa has the ability to borrow at rates significantly below the deemed rate. Going forward, Oshawa should be required to provide evidence of the rate it expects to pay on new loans rather than be allowed to use the default deemed rate.

If the Board approves a mid-term review option, then Energy Probe submits that the cost of long term debt should be fixed at the current forecast for each of 2015, 2016 and 2017. As part of the mid-term review, the cost of actual embedded long term debt would be included as part of the review, along with the then current forecast of debt issuances and rates for 2018 and 2019.

b) Depreciation

Energy Probe accepts the depreciation rates and methodology used by Oshawa in calculation the depreciation expense. However, whether there is an annual update or a mid-term review with some updates related to capital expenditures, then Energy Probe submits that the depreciation expense should be updated to be consistent with the other updates made.

c) PILs
As with the depreciation expense, Energy Probe submits that the calculation of PILs is appropriate but submits that in the event of annual updates or a mid-term review update, any changes in capital expenditures, working capital allowance, etc. should be fully reflected in the PILs calculation.

6.0 DEFERRAL AND VARIANCE ACCOUNTS

6.1 Should the existing deferral and variance accounts proposed for continuation be continued?

Oshawa is proposing to continue all of its Group 1 and Group 2 accounts with the exception of the Special Purpose Charge Assessment Variance Account (1521), which it proposes to close. This account is no longer needed beyond the end of 2014.

Oshawa is also proposing to continue the existing Pension Cost Differential Deferral Account and the Tax Rate Changes Deferral Account (Exhibit 1, Tab C, page 36). The establishment of the pension cost account was ordered by the Board in EB-2011-0073 as part of the last cost of service application for Oshawa.

Energy Probe agrees with the Oshawa proposal, with the exception of the Tax Rate Changes Deferral Account. Energy Probe submits that this account should be closed as of the end of 2014. The reason for this is that Oshawa has filed a cost of service application for the 2015 through 2019 period and should be subject to any risk of tax related changes, as is any business. The continuation of this account transfers the risks (both positive and negative) from Oshawa to ratepayers. Energy Probe submits that this is not appropriate under a Custom IR framework.

6.2 Are the proposed new deferral and variance accounts appropriate?

Oshawa is requesting approval of a number of new deferral and variance accounts as detailed in Exhibit 1, Tab C (pages 37-42) and as summarized in paragraphs 144 and 145 in the Argument-in-Chief. Energy Probe provides the following submissions on each of the requested accounts.

a) 2015 Revenue Variance Account
Under Issue 8.1 Energy Probe has submitted that the effective date for new rates should be based on the timing of the Board decision in this proceeding. If the Board agrees with that submission, then no account is required as there would be no amount calculated

based on the difference between interim and final rates over the January 1, 2015 to effective date period. If the Board accepts a January 1, 2015 effective date, then the account would be required.

b) Unbudgeted Regional Planning Investment Cost Variance Account

Energy Probe supports the request for this variance account. As noted elsewhere in this argument, the timing and cost of the contribution payable to HONI for the Enfield TS is at best questionable at this time. Energy Probe further notes that the allocation of costs for this station has been estimated at 50%. However, the outcome of phase 2 of the current EB-2013-0421 proceeding which deals with the allocation of costs associated with transmission line facilities in the Windsor-Essex region and the costs associated with the Leamington TS is still unknown and may have an impact on the allocation of costs for the Enfield project.

Due to the significant uncertainty surrounding both the costs and timing of this project, Energy Probe submits that the Board should approved the requested account.

If the Board determines that it will include a mid-term review for 2018 and 2019 as part of the IR plan, then Energy Probe submits that the Board should review the need for this account based on the information available in that mid-term review.

c) Distribution Plant Relocation Cost Variance Account

As submitted elsewhere in this argument, distribution plant relocations are part of the day to day business of an electricity distributor. Energy Probe has submitted that Oshawa has tried to eliminate a significant amount of risk through its various proposals. This account is one of those mechanisms.

In addition, a significant portion of the gross costs associated with plant relocations are offset by contributions required from the municipalities and road authorities.

As shown in the latest version of Appendix 2-AA (page 22 in Exhibit K1.4), the total gross costs associated with the Highway 407, Durham Region and City of Oshawa relocations have a total gross cost of about $13.9 million and associated contributions of about $6.2 million over the 2015 to 2019 period. The resulting net capital additions of $7.7 million represents about 10% of the total capital expenditures over this period.

Over the 2015 to 2019 period, the net distribution plant relocation costs included in the forecast is about $1.5 per year on average. If the actual expenditures were to deviate from the forecast by 50%, the impact on the revenue requirement in any given year would be approximately $75,000. This level is below the materiality threshold for Oshawa of $100,000 (Exhibit 1, Tab F).

Energy Probe submits that the Board should not approve this variance account as any variance from forecast is part of the normal risk faced by a distributor. The use of a variance account transfers the risk from the distributor to ratepayers. Energy Probe submits that this is not appropriate as part of a Custom IR plan.

d) Net New Connection Cost Variance Account

Elsewhere in this submission, Energy Probe has submitted that Oshawa has tried to eliminate a significant amount of risk through its various proposals. This account is one of those mechanisms.

Energy Probe submits that the variance in net new connection costs from forecast is a normal business risk and Oshawa should not be immune to this risk.

The net new connection cost forecast should be established based on the customer forecast approved by the Board in this proceeding and then Oshawa should be expected to live with that forecast. Energy Probe notes that if the actual customer connections vary from forecast, so will the net new connection costs, and that the result will offset one another. For example, if net new connection costs are higher than forecast due to higher customer additions, those incremental additions will provide Oshawa with additional revenues to offset the revenue requirement associated with the higher capital expenditures. If the net new connection costs are higher than forecast due to something other than higher customer additions, then this is a normal variance that Oshawa is at risk for.

Energy Probe further notes that as shown in the table on page 6 of the response to Undertaking J2.4, the estimated impact on the revenue requirement over the 2015 through 2019 period of a reduction in customer additions from 3.0% per year to 1.5% per year is $400,000 or an average of $80,000 per year. This is less than Oshawa's materiality threshold of $100,000.

Energy Probe submits that the Board should not approve this variance account as any variance from forecast is part of the normal risk faced by a distributor. The use of a variance account transfers the risk from the distributor to ratepayers. Energy Probe submits that this is not appropriate as part of a Custom IR plan.

e) Rate Smoothing Deferral Account

Under Issue 7.10 Energy Probe has submitted that a rate-smoothing mechanism is not required and is not appropriate. If the Board agrees with that submission, then no account is required. If the Board accepts the need for rate smoothing then the account should be approved.

f) CCIEIM Variance Account

Under Issue 1.5, Energy Probe has submitted that the Board should not approve the requested CCIEIM because of the numerous issues surrounding its practical application and value to ratepayers. If the Board does not approve the CCIEIM, then no variance account is required. However, if the Board does approve the CCIEIM or some variation of the proposal, then Energy Probe submits that the account should be approved.

g) Depreciation Expense Deferral Account

This account was agreed to in the Settlement Agreement in Oshawa's last cost of service rebasing application, EB-2011-0073. In particular, the parties, including Energy Probe, agreed that following the completion of an independent study, that Oshawa could apply for an accounting order that would track the adjustment related to the changes in the expected lives through a deferral or variance account.

Energy Probe supports the request for this account.

h) New Deferral and Variance Accounts Proposed by Energy Probe

Elsewhere in this argument, Energy Probe has submitted that the Board should accept a number of adjustments to the Oshawa Custom IR proposal should be made. A number of these adjustments would require a deferral or variance account for them to be implemented.

As such, Energy Probe submits that the Board should direct the establishing of an account that would track amounts associated with the proposed earnings sharing mechanism, the proposed efficiency adjustment mechanism and the proposed capital investment variance accounts.

6.3 Are the balances and the proposed methods for disposing of the balances in the deferral and variance accounts appropriate?

Oshawa did not request the disposition of any Group 1 or Group 2 accounts (Exhibit 9, page 2). The rationale for this proposal was that a large portion of the balance was driven by unusual movements in commodity and global adjustment costs in the latter part of 2013 and the early part of 2014.

As shown in the response to Interrogatory 9-Energy Probe-64, the balance in the accounts at the end of 2014 was receivable to Oshawa of about $4.2 million, but by the end of March, 2015 this had turned into a payable to ratepayers of $1.5 million. Given this significant change Energy Probe agrees with Oshawa that recovering the 2014 year-end balance and creating a larger payable to ratepayers in the future would not be appropriate. Energy Probe, therefore, agrees with Oshawa that no disposition is merited at this time.

Further, the evidence indicates that Oshawa intends to seek disposition of the Group 1 account balances annual as necessary over the 2015 to 2019 period and would do so in compliance with the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report. Energy Probe supports this proposal as it will ensure that balances do not grow too large over the IR plan term.

Oshawa is, however, asking for disposition of the requested Depreciation Expense Deferral Account (Exhibit 1, Tab C, pages 41-42) and confirmed that in the Argument-in-Chief (paragraph 147). Energy Probe submits that if the Board approves the Depreciation Expense Deferral Account, then it should also approve the disposition of this account. This account will not fluctuate, is material, and if it is not disposed of in this proceeding, will accumulate interest, resulting in higher costs to ratepayers.

7.0 COST ALLOCATION AND RATE DESIGN

7.1 Are the rate classes and their definitions proposed by Oshawa PUC appropriate?

Oshawa is not proposing any changes, additions or deletions to the rate classes and is maintaining the current definitions. As a result Energy Probe makes no submissions with respect to this issue.

7.2 Is the cost allocation proposed by Oshawa PUC for 2015 – 2019 appropriate?

Energy Probe submits that the cost allocation as proposed by Oshawa for 2015 to 2019 is appropriate subject to the submissions below.

Under Oshawa's original plan, a number of updates would be made annually, most notably the customer and load forecast. This has a direct impact not only the revenue forecast, but also on the costs allocated to those rate classes where there is a different customer or load forecast from that originally used and incorporated into the cost allocation model. Oshawa does not plan to adjust the cost allocation as part of its annual update (Tr. Vol. 2, pages 31-32).

Energy Probe submits that while a change in the customer and/or load forecast may not have a material impact in any given year, changes in either of these over the five year period may result in material impacts on some rate classes. If these changes are not managed over the five year term, then there may be a significant change required at the time of rebasing in 2020. As a result, Energy Probe submits that if the Board accepts the annual adjustments as proposed by Oshawa, then it should also direct Oshawa to update the cost allocation to reflect these changes.

If the Board were to adopt the mid-term review option, there would be no need to update the cost allocation and rate design models for 2016 or 2017 as there would be no impact in these years. However, as part of the mid-term review, Energy Probe submits that the Board should direct Oshawa to update the cost allocation and rate design models based on the proposed changes for 2018 and 2019. This would ensure a gradual change in cost allocation rather than waiting for 2020 rebasing.

Energy Probe also submits that given the different forecast scenarios under consideration at this time in this proceeding, that the Board should direct Oshawa to update its cost allocation and rate design models to incorporate whatever forecast the Board ultimately approves for each of the years and that this information be provided as part of the draft rate order so parties could review and, if necessary, comment on it.

7.3 Are the revenue-to-cost ratios for all rate classes over the 2015-2019 period appropriate?

Energy Probe submits that the methodology used by Oshawa to move all rate classes to be within the Board approve revenue to cost ratio policy ranges is generally appropriate. This methodology is illustrated in Tables 7-1 through 7-15 in Exhibit 7, and as corrected in the response to Interrogatory 7-VECC-46.

This methodology is illustrated best in Table 7-3 for the 2015 revenue to cost ratios. The first step is to bring all classes that are above the Board approved range to the top of the range and to bring all classes that are below the Board approved range to the bottom of the range. In Table 7-3 Oshawa has done this for the GS < 50 class (from 130.5% to 120%), the GS intermediate class (from 144.6% to 120%), the sentinel lighting class (from 131.8% to 120%) and the large use class (119.8% to 115%).

To remain revenue neutral, Oshawa has increased the revenue to cost ratios for the street lighting class, USL class and residential class. Moreover, Oshawa has proposed to increase each of these classes to the same revenue to cost ratio. Energy Probe supports this approach. It ensures that no rate class is subsidized to a greater extent than any other class.

In Table 7-3 this results in raising the revenue to cost ratio for the street lighting class from 80.2% to 95.5%, the USL class from 88.9% to 95.5% and residential class from 93.8% to 95.5%.

In Interrogatory 7-Staff-35 Oshawa was asked why it was not proposing to move the rate classes more toward the middle of the Board approved ranges over the 2015 through 2019 period. Oshawa responded that it did not believe the cost allocation process had improved. Energy Probe agrees with Oshawa. There have been no significant improvements in the cost allocation model that would suggest a shrinking of the revenue to cost ratio ranges was appropriate. In addition, the same cost allocation model has been used for each of 2015 through 2019. By definition, the level of accuracy in the 2019 model is the same as in the 2015 model, so no narrowing of the ranges would be appropriate.

Finally, Energy Probe notes that based on the decisions by the Board in this proceeding, the cost allocation and rate design models will need to be updated for all five years. Energy Probe submits that the Board should direct Oshawa, as part of the draft rate order process to file update cost allocation and rate design models and to clearly reflect the proposed changes in the revenue to cost ratios from the status quo ratios calculated in those models so that all parties can see the application of the methodology described above in each of the years.

7.4 Are the proposed fixed and variable charges for all rate classes over the 2015-2019 period reasonable?

Oshawa proposes to raise the fixed charge split to 50% in 2015 (Exhibit 8, Table 8-4). Energy Probe submits this change is appropriate, given the Board's policy to move this ratio to 100% over the next number of years.

With respect to the other rate classes, Energy Probe notes that the proposed rates are all within the range of the floor to the ceiling derived by the model, except for the GS 50 to 999 (in 2016 through 2019), GS Intermediate and Large Use classes (Exhibit 8, Table 8-12).

As shown in Table 8-5 in Exhibit 8, Oshawa is proposing to increase the fixed component of the rate for the Large Use class, keeping it relatively flat for the GS 50 to 999 class and decreasing it for the GS Intermediate class. In all cases, however, the fixed charge is projected to increase (Table 8-12) despite the fact the fixed charges are already above the ceiling per the cost allocation model.

Energy Probe submits that this is inconsistent with Board Policy as set out on page 12 of the Report of the Board: Application of Cost Allocation for Electricity Distributors (EB-2007-0667) dated November 28, 2007. Under this policy, a distributor whose current fixed charge for a class is above the ceiling should not propose further increases to the fixed charge for that class.

Energy Probe further submits that it would be unwise to deviate from the current policy while the Board examines the rate design issue for commercial and industrial customers as has been initiated in EB-2015-0043.

7.5 Are the proposed charges for miscellaneous services over the 2015-2019 period reasonable?

Energy Probe submits that the Board should direct Oshawa to do a study to determine if the proposed charges for miscellaneous services is covering the costs of providing those services. This study would be filed as part of the rebasing application in 2020.

If the Board were to update the study done several years ago on a generic basis, then Oshawa would not be required to provide its own study, unless it felt that its circumstances were sufficiently different from the generic results as to justify its own study.

Energy Probe is concerned about the time that has elapsed since the last generic review that established the current charges and the impact that has on costs related to inflation. This would be amplified by the end of 2019. In such a situation, the current charges may no longer be sufficient to cover the costs for providing the services, result in distribution rates subsidizing the costs associated with providing these miscellaneous services.

7.7 Are the proposed line loss factors over the 2015-2019 period appropriate?

Energy Probe submits that the line loss factors should reflect the most recent historical data available, which can be found in the response to Interrogatory 8-Energy Probe-63. This calculation uses data from 2010 through 2014 instead of the original information used in Exhibit 8, which was based on 2009 through 2013 data.

7.8 Is the proposed Low Voltage service rate for 2015 – 2019 appropriate?

As Oshawa does not appear to have a low voltage rate, Energy Probe makes no submissions on this issue.

7.9 Are the rate and bill impacts over the 2015-2019 period acceptable?

Energy Probe notes that there are different levels of rate and bill impacts depending on the scenarios and the inclusion of rate riders and whether or not rate smoothing is included.

Energy Probe has viewed this issue based on average increases across all years, thereby eliminating the rate smoothing issue.

The response to Undertaking J1.2 Updated, which is based on Oshawa proposed annual adjustments, shows that the distribution rate impacts are in the -0.3% to 10.1% range, with most customers impacted with an average increase of about 7% per year. The same undertaking response shows the average total bill impact over the five years is 2.1% or less for all classes.

The response to Undertaking J2.11 Corrected shows the rate and total bill impacts assuming no annual adjustments and the lower customer and load forecast. In this case the distribution rate impacts are in the 1.0% to 11.1% range per year. The average total bill impact over the five years is 3.5% per year or less for all classes.

In addition to the change in the customer and load forecast, the response to J2.11 Corrected includes recovery of a rate rider for the foregone January 1, 2015 through August 31, 2015 over a four year period. This rate rider was not included in the response to J1.2 Updated. The inclusion of this rate rider accounts for about 50% of the average annual rate increase (Tr. Vol. 4, pages 11-13).

Energy Probe submits that the increases proposed in the distribution rates are excessive, despite the relatively modest impact on the total bills. However, assuming the Board adopts some of the submissions of intervenors that would reduce the overall revenue requirement, the rate impacts should be moderated to levels that are more acceptable.

<u>7.10 Is a rate-smoothing mechanism required? If so, is the proposed mechanism appropriate?</u>

Energy Probe submits, for a number of reasons, that rate smoothing is neither required nor desired.

First, it adds to the total cost paid by customers over the five year period. The additional cost to ratepayers is $157,000 as identified in the response to Interrogatory 1-VECC-2. Energy Probe submits that in the absence of any need for rate mitigation this is an unnecessary additional costs to burden ratepayers with. As indicated on page 13 of Exhibit 1, Tab C, no rate mitigation is required because the increases in the total bill are less than 10%. In fact, as shown on page 105 of Exhibit 8, are all less than 4% in 2015, which is the rate year the smoothing proposal was designed to mitigate.

Second, the recovery of the amounts deferred in 2015 through 2017 in 2018 and 2019 will increase rates in those years. Energy Probe submits it would be risky to increase rates in those years given that no one knows what the cost of power will be in those years. Combined with transmission rate changes and other potential regulatory rate changes, the increase in 2018 and 2019 could well be more than the total bill impact forecast for 2015. The smoothing proposal would only exacerbate the problem.

Third, the smoothing proposal generates an intergenerational inequity. Ratepayers in 2015 and 2016 are being subsidized by ratepayers in 2018 and 2019. With strong customer forecast by Oshawa, the difference between these two groups of customers will be larger than for most other distributors. New customers will provide a subsidy to existing customers.

This inequity is not limited to that between generations. It would also result in customers who implement conservation measures between now and 2018 being subsidized by those customers who do not implement conservation measures over this period, even though they may have already done so. This is because the volumes for the customers the adopt conservation measures will represent a lower proportion of the volumes in 2019 than they do in 2015.

The inequity also extends to customers impacted by economic conditions. Customers that expand their facilities and increase use would be subsidizing other customers that have maintained their average use or seen it decline due to economic and business conditions.

Finally, Energy Probe submits that the smoothing proposal hides the true cost of electricity distribution from customers. If the Board is concerned with educating customers so that they better understand the demands on the electricity infrastructure, hiding rate increases from them is not the way to do it.

For all the above reasons, Energy Probe submits that the proposed smoothing mechanism is neither required nor appropriate.

8.0 IMPLEMENTATION

8.1 What should the effective date be for the new rates?

Energy Probe submits that the effective date for the new rates should be the first of the month in which the Board delivers its Decision. This is consistent with past Board practice.

Oshawa filed its application in late January, which was already after the proposed effective date for rates. Given the Board's filing timelines, this application was nine months late.

Energy Probe notes that in its Argument-in-Chief, at paragraph 157, Oshawa states that it is not aware of any comprehensive discussion by the Board of the principles that it applies in determining the effective date for rates relative to the timing of the filing of a rate application and the timing of the resulting decision.

Energy Probe has attached Appendix B to this submission. Appendix B is the relevant pages dealing with the effective date for the payment amounts for prescribed facilities of Ontario Power Generation Inc. ("OPG") in the November 20, 2014 Decision with Reasons in EB-2013-0321 ("OPG Decision"). Energy Probe submits that the Board's findings in that case are equally applicable to Oshawa.

Energy Probe submits that the choice of the type of framework to be applied for was entirely in Oshawa's control. Furthermore the timing of the application was entirely within Oshawa's control. It could have expedited the process by hiring additional external and/or internal resources to complete the filing on time. It could have made decisions with respect to outsourcing the various third party reports earlier in order to incorporate the results into its application. Most importantly, Oshawa could have asked the Board for relief for 2015 rates given that it had triggered an offramp by under earning by more than 300 basis points in 2013 (Undertaking TC1.12), and acknowledging its intention to file a Custom IR plan proposal beginning January 1, 2016. It chose not to.

When reviewing the Board's Decision in EB-2013-0321, there are many findings of the Board that are as applicable to Oshawa as they were to OPG; Energy Probe highlights some of these blow.

Energy Probe submits that there is no legal requirement that the Board set the effective date of its final orders to the date that rates were declared interim (OPG Decision, page 132-133).

Oshawa argues that the revenue shortfall in the January 1, 2015 to effective date period totals about $1.8 million (Argument In Chief, paragraph158) and that to deny Oshawa recover that amount results in a situation that would be penal and unfair. The Board dealt with this in the first full paragraph on page 134 of the OPG Decision. Energy Probe submits that a key factor in this proceeding is that the Oshawa plan is a Custom IR plan. IR stands for Incentive Regulation. As the Board correctly pointed on the OPG Decision, under incentive regulation rates are deliberately de-coupled from a utility's actual costs.

In the OPG Decision, the Board declined to accept the effective date as that requested by OPG because *"it is contrary to the Board's long-standing practice of setting rates on a forecast (i.e. forward test year) basis"* (OPG Decision, page 134). The Board then went on to state that:

> *"The Board’s general practice with respect to the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding. This practice is predicated on a forecast test year which establishes rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the ratepayer to make informed decisions based on approved rates. The forecast test year is a pillar in rate setting and the Board’s practice must be respected."* (OPG Decision pages 134-135).

Energy Probe strongly supports this statement.

Energy Probe also supports the Board's statement it must control its regulatory process and that in cases where utilities have not filed their applications in time to have rates in place prior the effective date, the Board's practice has typically been to not allow the utility to retrospectively recover the amounts from the from period where the interim order was in effect (OPG Decision, page 135). Examples provided by the Board include

Sioux Lookout (EB-2012-0166), Hydro Hawkesbury (EB-2013-0139), Centre Wellington (EB-2012-0113) and Fort Frances (EB-2013-0130).

Under the RRFE, Energy Probe submits that the focus is on the customer, or ratepayer. Ratepayers that made consumption decisions from January 1, 2015 to the effective date, assuming it is later than January 1, 2015, believe they have already paid their electricity bills. These ratepayers would be surprised and shocked to learn that they will be responsible for additional costs to be recovered through higher rates to be included on future bills. The Board dealt with this at pages 135-136 of the OPG Decision. In particular, it highlighted the fact that some level of inter-generational inequity would take place to the extent customer profiles changed over the proposed recovery period. Energy Probe agrees with this assessment and has dealt with the issue is more detail under Issue 7.10 above.

In summary, Energy Probe submits that the timing and form of the application was solely in Oshawa's control and the Board's policies regarding effective dates are, or should be, well known. For the reasons provided above and by the Board in the OPG Decision, Energy Probe submits that an effective date of the first of the month in which the decision in this proceeding is reached is appropriate.

8.2 Other than the proposed annual adjustments to revenue requirement outlined in Exhibit 10 Tab D of the pre-filed evidence, are there any other adjustments to rates to be made annually (e.g. Retail Transmission Service rates)?

As noted elsewhere in this submission, Energy Probe does not support the annual adjustments as proposed by Oshawa. However, Energy Probe does see merit in the mid-term review option, accompanied by the mechanisms detailed in Issue 1.2.

Energy Probe supports the adjustment on the cost of capital on an annual basis regardless of the form of the IR plan. In addition, Energy Probe supports the working capital allowance adjustment to the cost of power as a result of changes in RPP and non-RPP prices. This update can be done at the same time as the cost of capital update and should be based on the most recent price report available.

Energy Probe also submits that changes to the retail transmission service rates should be done at the time of the annual updates for cost of power and cost of capital. This should help minimize the amounts that accumulate in the various variance accounts that exist for these rates.

Energy Probe notes that 2015 RTSR's were updated in the response to Interrogatory 8-VECC-49 to reflect the approved uniform transmission rates for 2015. However, these rates will need to be updated to reflect changes to the load forecast approved by the Board.

C - COSTS

Energy Probe requests that it be awarded 100% of its reasonably incurred costs. Energy Probe worked with other intervenors in this proceeding to ensure complete coverage of the issues with a minimum of duplication.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

July 24, 2015

Randy Aiken
Consultant to Energy Probe