EB-2014-0101

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998;*

AND IN THE MATTER OF an Application by Oshawa PUC Networks Inc. for an Order approving rates and other service charges for the distribution of electricity for the years 2015 through 2019.

REPLY ARGUMENT

INTRODUCTION

1. OPUCN was pleased, in reading the arguments filed by the parties, that, in the end, all of them at least started to reflect some “outside the box” thinking on options for *RRFE* compliant rate setting, including truly customizing a “Custom IR” rate plan.

2. OPUCN appreciates the several comments offered in argument recognizing its efforts towards creative thinking and *RRFE* compliance.

3. OPUCN also appreciates comments from several parties that reflect that OPUCN’s significant efforts in presenting a rate application that is both thoughtful and carefully developed has not gone unnoticed.

4. In the end, all parties have essentially acknowledged that a modified form of Custom IR plan for OPUCN would substantially address the Board’s expectations in the *RRFE* for incentive rate making in general, and for Custom IR Plans in particular. The parties have suggested various versions of a rate plan characterized by one mid-term review in lieu of the annual rate adjustments proposed by OPUCN.

5. While formulaically criticizing OPUCN for the number of in-period rate adjustments proposed, parties have gone on to support a number of OPUCN's proposed adjustments, and variously propose a number of additional adjustments or true-ups.

6. Parties have generally accepted both cost of capital and cost of power (for application to working capital calculation) annual updates.

7. Parties have also advocated capital investment ring fencing.

8. OPUCN's proposal already includes capital ring fencing (though symmetrical rather than one sided in favour of ratepayers) for: i) regional planning costs; ii) costs driven by 3rd party requirements for relocations; and iii) net new connection costs. In its Argument in Chief (paragraph 175, see also Exhibit J2.4, page 7), OPUCN also accepted additional ring fencing for system renewal capital expenditures for projects not undertaken during the rate plan period.

9. Further, in the event that OPUCN realizes capital investment efficiencies in execution of its MS-9 Distribution Station and those system renewal investments undertaken during the plan period as forecast, OPUCN is proposing, through its Capital Cost Investment Efficiency Incentive Mechanism (CCIEIM), to allocate to ratepayers half of the capital cost efficiencies so realized.

10. OPUCN's proposal thus effectively "ring fences" capital investments such that unspent investment funds are credited back, in whole or (in the case of the CCIEIM) in part, to ratepayers.

11. In the result, the main issue joined as between OPUCN and the parties regarding adjustments during the plan period relates to OPUCN's proposed adjustments to address the uncertainty over the 5 year plan period related to its customer growth forecast. OPUCN addresses this issue under the "Forecasts" topic, below.

12. OPUCN acknowledged in its Argument In Chief (paragraph 172), and having carefully and open-mindedly considered the arguments raised by parties

confirms, that OPUCN can accept that replacement of its proposed annual rate adjustment proposal with one, pre-scoped mid-term review might be a better approach in the current circumstances, and is one that it can effectively operate under. This approach would largely address the "regulatory burden" and "number of adjustments" concerns raised by the parties.

13. In respect of forecast cost levels, unfortunately, though not surprisingly, parties have all argued for cost reductions. This despite comprehensive evidence that OPUCN is already a highly efficient distributor, and has requested approval for costs (and associated rates) that would deliver an expected outcome of improved efficiency over the 2015-19 period.

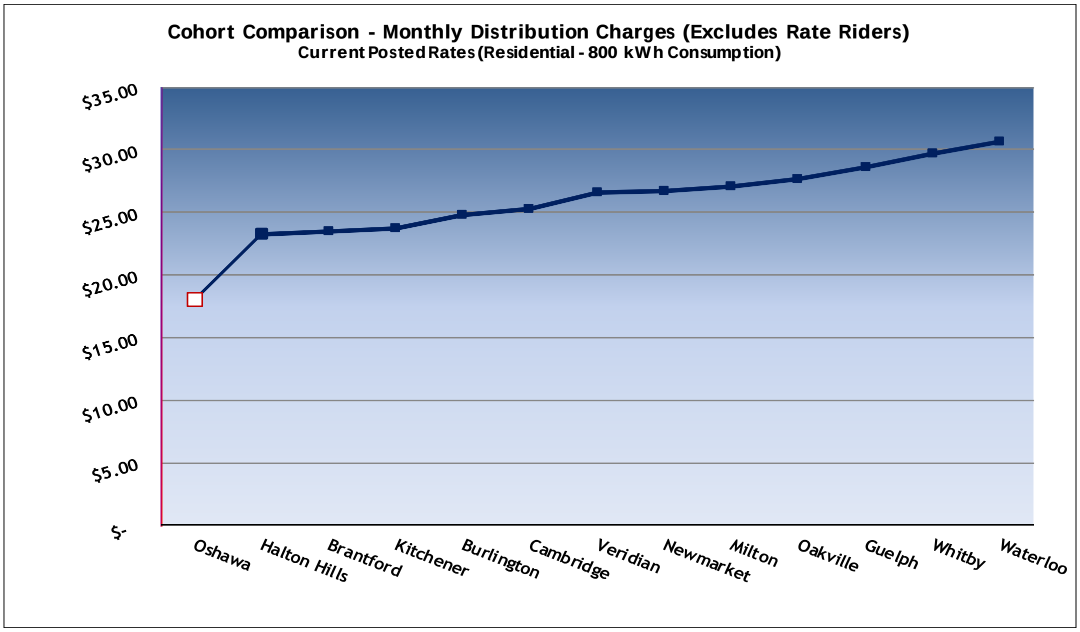
14. As summarized in its Argument in Chief (paragraph 70), the evidence[1] gleaned from the OEB's 2013 Yearbook of Distributors illustrates OPUCN's current efficiency:

Metric	OPUCN	Peers*	Ontario Average
Distribution revenue per customer	$363	$500	$691
Net Fixed Assets per Customer	$1,436	$1,977	$3,080
OM&A per Customer	$208	$246	$325
Customers per FTE	750	544	Not calculated.

***** OPUCN's former efficiency cohort.

15. OPUCN has had the lowest monthly distribution charges compared with its OEB defined peer group[2]:

[1] See Exhibit 1, Tab C, pages 23 through 33.
[2] Presentation to the Hearing Panel and parties on April 2, 2015.



16. As fully referenced in its Argument in Chief (paragraph 71), OPUCN has also presented analysis which demonstrates that it will remain highly efficient through, and at the end of, the proposed rate plan term:

a. OPUCN's forecast 2019 OM&A per customer remains <u>un</u>changed from its 2013 level. (If adjusted for 1.5% growth throughout the term, as advocated by Board Staff, this metric becomes $222, or an average annual increase of 1.1% which is below forecast inflationary indexes that include productivity factors.)

b. OPUCN's forecast 2019 net fixed assets per customer remains <u>lower</u> than average comparable LDCs for <u>2013</u>. ($2,200 adjusted for 1.5 % customer growth over the plan term, which continues to be below the industry average and comparable to Peers 2013 position.)

c. OPUCN's distribution revenue per customer is increasing over the plan period at just over half the rate of increase in OPUCN's overall revenue requirement over the period (2.5% compared to 4.7%). (At 1.5% growth, the increase in distribution revenue per customer would be 3.8%.)

d. OPUCN's forecast OM&A cost increase is being held at approximately 2% per year, below the Conference Board of Canada inflation forecasts for the City of Oshawa, and in the face of a customer growth forecast of 3% per year.

e. Despite both customer growth and increasing regulatory requirements, FTE's at the end of the rate plan period are to be maintained at today's level, which in the face of forecast customer growth represents the avoidance of 6 FTEs. (If growth is actually only 1.5%, the FTE's avoided will still be 3.)

17. Despite this evidence, intervenors have, as they habitually do, focussed their analysis on advocating further cost reductions. All of these arguments assume that significant cost reductions will somehow be manageable by OPUCN, without sacrificing reliability or access to electricity service.

18. These arguments essentially ignore the findings from the Pacific Economics Group LLC (PEG) modelling that OPUCN has "baked in" to its rate proposal total factor productivity that exceeds the Board's expectations by a factor of 4! OPUCN has proposed a revenue requirement over the rate plan term that delivers an implicit stretch factor of 0.87%, which is 0.66% greater than the Board's mandated 0.21%.[3]

19. Arguments that the *PEG* benchmarking is somehow deficient (because they compare historical periods to a future period, or because they merely present OPUCN benchmarking against itself) are either irrelevant or erroneous. OPUCN notes that no party sought to cross-examine PEG at the hearing on any of these assertions. OPUCN responds further to these arguments below. OPUCN strongly believes that PEG's econometric modelling is the best evidence available for 3rd party benchmarking of an Ontario electricity distributor's rate plan.

20. In respect of its Capital Investment Plan, OPUCN has conceded[4] that its Asset Investment Prioritization (AIP) tool is a "work in progress" which could, and will, be improved. Parties have argued that the Board should reduce OPUCN's capital budgets from those as filed, and thus essentially force further prioritization and deferral of some of the capital investments identified in OPUCN's comprehensive Distribution System Plan (DSP).

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[3] See Argument in Chief, paragraph 75.
[4] Transcript Volume 2, page 149.

21. The evidence is that all of the capital projects included by OPUCN in its comprehensive 5 year DSP are required either:

a. pursuant to Metsco's initial prioritization review (as part of its Asset Condition Assessment);

b. for OPUCN to meet its regulatory requirements (in respect of the Board's long-term-load-transfer expectations[5]);

c. to address the government's "smart grid" mandate (in respect of the smart grid pilot[6] as well as the "smarter grid" investments proposed by OPUCN following the guidance provided in the Utiliworks *Smart Grid Roadmap and Financial Analysis*[7]); and/or

d. to address customer expectations regarding quicker outage identification and resolution and better customer communications regarding such outages[8].

22. OPUCN continues to believe that all of these identified projects are required and/or appropriately undertaken during its proposed rate plan term, and that its capital expenditure forecast and associated revenue requirement should be approved as requested.

23. In the event that the Board is persuaded otherwise, OPUCN requests further guidance in respect of which of the foregoing mandates/requirements OPUCN's capital investments should be deferred.

24. Despite OPUCN having evidenced an OM&A cost level for 2015 that benchmarks very favourably against comparable Ontario electricity distributors, and despite OPUCN having proposed rates through 2019 which reflect OM&A cost escalation below inflation, intervenors have stuck to their habitual arguments for;

a. mechanical calculation of test year (in this instance 2015) OM&A based on bridge year (in this case, 2014) actuals; and

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[5] Argument in Chief, paragraph 113.
[6] *Ibid*
[7] Exhibit 2, Tab B, Schedule 4.
[8] Argument in Chief, paragraph 39.

b. formulaic indexing, inclusive of yet additional productivity expectations, for OM&A escalation over the rate plan term.

25. Starting with an appropriate OM&A cost level for 2015 and then applying the "indexing" proposed by some of the intervenors would result in OM&A over the plan period that exceeds OPUCN's proposed O&M by more than $2 million (over $600 adjusted for 1.5% customer growth). OPUCN does not think that such an approach would best serve the interests of its customers.

26. As was OPUCN's Argument in Chief, this Reply Argument is organized in accord with the main topics on the Board Approved Issuers List for this proceeding.

ISSUE 1: CUSTOM APPLICATION

Cost of Service vs. Custom IR: A False Dichotomy

27. Parties have generally assumed that there is a requisite distinction between the *RRFE*'s Custom IR model and a multi-year cost of service based rate application. This is a false dichotomy.

28. OPUCN has comprehensively referenced the Board's parameters for a Custom IR in its Argument in Chief (paragraphs 26 through 36), and there explains how its application has addressed each of these parameters. The first of those parameters is that in a Custom IR plan the Board anticipates that rates will be set based on a five year forecast of a distributor's revenue requirement and sales volumes.

29. Parties who have been critical of OPUCN's "bottom up" approach to forecasting of its costs should consider their chagrin, and the Board's, had OPUCN filed single line item rate requests based on a top down formula. The Board would never set rates without being satisfied regarding underlying cost details, and intervenors would never tolerate filings without exhaustive detail in that respect.

30. "Outcome based regulation" does not mean that one disregards inputs. It means that once acceptable outcomes are identified, the subject utility is held accountable for those outcomes. In Custom IR, the method for identifying acceptable outcomes is left open, but what is certain is that the method must include presentation of comprehensive cost of service information for each of the relevant test years. OPUCN has provided that information.

31. OPUCN has also provided robust, independent benchmarking evidence to confirm the efficiencies inherent in its cost of service forecasts.

32. Imposing a formulaic "stretch factor" automatically, regardless of the strength of the cost of service information provided by a Custom IR applicant, will inevitably lead to gaming of applications. Why should a distributor present it's absolutely

best attempt at cost containment as a base for its revenue request when it is a foregone conclusion that the Board will take that best effort, and impose yet another layer of expected efficiency.

33. OPUCN respectfully submits that a better approach, and the one envisioned by the *RRFE*'s emphasis on the "customized" nature of a Custom IR plan, is to be open to demonstration by an applicant that the revenue request presented reflects superior efficiencies sufficient to demonstrate inherent productivity. The onus remains on the applicant, no doubt.

34. OPUCN submits that this is precisely the reason for the prominent role of benchmarking in support of a Custom IR proposal.

35. Under a formulaic price cap approach, like 4th Generation Price Cap IRM, benchmarking (by PEG) and an associated formula term for productivity provides external assurance of an efficient rate outcome.

36. In OPUCN's case, there is eminently qualified and independent evidence (from PEG, and relying on the OEB's own framework for calibration and validation of productivity) that OPUCN has presented cost forecasts that reflect continued superior productivity. In fact, PEG has validated that OPUCN's rate proposal reflects <u>more</u> productivity than would be obtained under the standard 4th Generation Price Cap methodology.

37. Imposing an additional rate reduction on rates already benchmarked as reflecting superior productivity would send the wrong message to distributors. The message would be that no matter how robust and transparent your evidence, you will be dinged.

38. OPUCN has presented an honest application, and has tested that application using the Board's own preferred productivity benchmarking methodology. There is no padding built in to OUPCN's forecasts. The evidence is that OPUCN's OM&A is lean, and that all of its proposed capital projects are appropriately costed (these two are externally benchmarked) and required during the plan

term. OPUCN does not believe that it can make up externally imposed revenue shortfalls anywhere else.[9]

39. For the most part, the arguments filed do not consider the careful references by OPUCN in its Argument in Chief to each of the *RRFE* parameters for Custom IR. One noted exception is SEC.

40. SEC states[10] that the *RRFE “explicitly references the form of the plan to be a custom index”*. The reference provided by SEC for this statement is to the rate options comparison table found at page 13 of the *RRFE* report. SEC has not provided any explanation of what it suggests “custom index” means. (Neither does the *RRFE* report.)

41. OPUCN addressed this reference at paragraphs 29 – 32 of its Argument in Chief, and for the reasons carefully set out there submits that it does <u>not</u> mean that a Custom IR plan is simply, and only, a modified 4th Generation Price Cap index with advance capital modules (ACMs).

42. Rather than addressing OPUCN’s detailed argument regarding what the *RRFE* itself says, the parties refer to the Board’s recent Hydro One decision in characterizing OPUCN’s application as “non-compliant” with the *RRFE*’s Custom IR framework.

43. The Hydro One decision was issued after OPUCN filed its application. Until that decision, the only other guidance provided by an OEB Hearing Panel was Enbridge’s 2012 application for 2014-18 rates [EB-2012-0459]. In the Enbridge decision, the Board accepted an application based on 5 years cost of service forecasts, precisely like OPUCN’s.

44. It is respectfully submitted that having determined, for the reasons comprehensively related in its Argument in Chief (see paragraphs 17-25), that neither of the other two available rate setting options could be applied to its

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[9] Transcript Volume 1, page 36, lines 24 through 27.
[10] SEC Argument, paragraph 3.2.8.

circumstances, it was entirely reasonable for OPUCN to proceed with extensive work to fashion a rate application that addressed the rate plan format that, to that time, had only been considered by the Board in the Enbridge decision. OPUCN respectfully requests that, regardless of this Hearing Panel's interpretation of the Hydro One decision, this timing and the reasonableness of OPUCN's actions be taken into consideration in determining an appropriate ruling on this application.

45. In any event, OPUCN has considered the guidance provided by the Hearing Panel in the recent Hydro One decision, and submits that the instant application is fully consistent with that guidance.

46. Here is the full excerpt from the Hydro One decision segments of which have been quoted in various of the arguments in this case:[11]

> *Cost of service rate-setting has an important role in performance-based regulation regimes to periodically examine in detail the costs and activities underpinning rates. However, the OEB continues to believe that multi-year incentive rate-setting, with its emphasis on results, is the most effective way to incent behaviour similar to that seen in commercially-oriented, consumer market-driven companies. 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 revealing superior performance and encouraging best practice. The decoupling of rates from the utility's own costs simulates a competitive market environment and is more compatible with an outcomes-based approach to regulation.*

47. There is nothing about OPUCN's application that is necessarily inconsistent with this guidance:

a. OPUCN has proposed a multi-year rate plan. Setting rates for multiple years, and allowing efficiencies realized to benefit shareholders, is the basis for incenting behaviour through a multi-year rate plan as endorsed by the Hydro One Hearing Panel.

b. While OPUCN has requested rates to reflect its own forecast costs, it has only done so on the basis that its forecast costs compare favourably with the external cost benchmarks which OPUCN has obtained and presented.

[11] EB-2013-0416/EB-2014-0247: *Decision*, March 12, 2015, page 14.

A number of parties have criticised PEG's benchmarking as only comparing OPUCN against itself. This is factually incorrect. PEG's benchmarking model was created based on the observed costs of all Ontario electricity distributors. The benchmarking results that PEG has produced for OPUCN are derived by comparing OPUCN's forecast costs with the costs for OPUCN predicted by PEG's benchmarking of all Ontario distributor's costs relative a uniform set of cost drivers (customer numbers, customer growth, kilometers of line, demand and energy). PEG's model validates that OPUCN's forecast costs reflect efficiency significantly superior to that which would be expected as a result of normalizing for OPUCN's particular cost drivers the actual costs of other Ontario electricity distributors. This is the very sort of benchmarking external to the utility that the Hydro One panel identified as revealing superior performance and encouraging (indeed locking in) best practices.

c. The "outcomes" that the Board can rely on in OPUCN's case, as presented in this application, is that its requested rates reflect (and lock in, for the benefit of ratepayers) costs that are <u>lower</u> than predicted using the Board's own adopted econometric benchmarking model. OPUCN's proposed cost performance exceeds the Board's default IRM methodology stretch factor by 0.66%.[12] As opined by PEG itself[13] [emphasis added]:

> *OPUCN's custom IR proposal uses rigorous <u>external</u> cost and productivity benchmarking to show that the cost forecasts offer customers good value and the prospect of continuous improvement...*
>
> *....*
>
> *The Board can thus be satisfied that OPUCN's "utility performance" under the Custom IR rates proposed will continue to reflect strong cost efficiencies and <u>quantifiable value to OPUCN's customers</u>.*

d. Under OPUCN's proposal, its rates <u>will</u> be decoupled from its own costs, not by virtue of a generic formula designed for (and appropriate for) a relatively "steady state growth" distributor, but by virtue of the fact that OPUCN's rates will be set based on a forecast of costs validated to reflect continued superior efficiency, and then left as set for the 5 year rate plan term regardless of actual costs during the term. (OPUCN submits that the in-term adjustments that it proposes are appropriate, and that adopting the one mid-term review model proposed by Staff will further de-couple rates from OPUCN's ongoing costs).

[12] OPUCN Argument In Chief, paragraphs 74 through 76.
[13] Exhibit 10.0-Staff-44

48. OPUCN notes that one of the reasons articulated by the Hearing Panel in the Hydro One case for rejecting Hydro One's Custom IR proposal was weak benchmarking evidence (see pages 15-17 of the Hydro One decision).

49. OPUCN submits that its Custom IR proposal is fully consistent with the guidance for Custom IR applications articulated by both the Enbridge and the Hydro One Hearing Panels.

50. To the extent that the Hearing Panel in this proceeding concludes otherwise, it must then consider both the Enbridge decision, which accepted a "cost of service based" Custom IR proposal, and the Hydro One decision, which rejected Hydro One's proposed "cost of service based" proposal for a number of reasons (including the lack of external benchmarking), and determine which elements of each best reflect this Hearing Panel's view of the Board's intentions regarding Custom IR.

Balance of Risk & Proposed In-Term Adjustments

51. Parties have also asserted that OPUCN's proposal for annual rate adjustments removes much or all of its risk.

52. OPUCN acknowledges and agrees that "living within forecasts" is a central element of the Custom IR model. However, it is overly simplistic to assume that all types of forecasts are equal when it comes to ability to manage risk.

53. OPUCN's system renewal capital investment requirements and OM&A budgets are good examples of these types of costs. In both of these instances OPUCN is ready, willing and able to assume full responsibility to manage risks.

54. In OPUCN's particular circumstances, growth forecasts are not of the same ilk.

55. As reviewed in greater detail below, OPUCN is faced with the unique situation that its historically observed growth and its best forecast of growth do not line up. The divergence is due exclusively to plans of external parties, over which OPUCN can have no control.

56. There is no regulatory justification for, reasonable incentive value in, or basic “fairness” argument for, expecting OPUCN to live with revenue consequences of significant departure by third parties from their current plans for accelerating development within Oshawa.

57. While OPUCN is willing to live with in-year risks associated with these ambitious city and regional growth plans, requiring OPUCN (or ratepayers) to absorb potentially large swings in revenue over the course of a 5 year rate plan term resulting from external planning changes completely beyond OPUCN’s ability to predict, let alone control, serves no constructive regulatory purpose or policy.

58. It is one thing to be expected to manage risk. It is quite another to be expected to simply passively (for lack of ability to respond) absorb it. The former expectation is legitimately part of proactive regulatory policy. The latter is simply, in the result, penal.

59. Advocates of this approach either overestimate OPUCN's ability to simply cut or avoid expenditures, or view rate setting through the singular lense of the consumer's interest without due regard to the counterbalancing, and equally legitimate, interest of the utility shareholder. This balance between the interests of the ratepayer and the shareholder which is the fundamental objective of economic utility regulation is absent from many of the intervenor positions advanced in argument in this proceeding.

60. Beyond the growth forecast conundrum, arguments that OPUCN’s proposal for annual rate adjustments removes much or all of its risk ignore the evidence that:

a. OPUCN has proposed to remain at risk in respect of approximately 85% of its revenue requirement[14]; and

b. those in-term adjustments which are proposed are designed to address risks that are completely exogenous and for which OPUCN cannot plan so much as react.

[14] Exhibit TC1.2; Exhibit J2.1.

61. OPUCN's proposed variance treatment for net new connection costs is intended to protect ratepayers as much as the shareholder, given the ambitious growth forecast which OPUCN is faced with.[15]

62. OPUCN's proposed variance treatment for costs driven by 3rd party relocation requests, and regional planning requirements are similarly equally protective of ratepayers and the shareholder. None of the parties have argued against this symmetry of approach.

63. OPUCN's proposed load forecast adjustment has been discussed above.

64. OPUCN's proposed adjustment to reflect updated cost of capital parameters and cost of power (for working capital calculation purposes) have been generally accepted. Neither of these cost categories are subject to control by OPUCN. Both are largely dependent on interest rate forecasts difficult to make with any precision 5 years out. Fixing risk of these costs with OPUCN serves no regulatory or incentive purpose, other than increasing the utility's risk profile.

65. This is a complete list. There are no other proposed adjustments.

66. None of these adjustments relieve OPUCN from its obligations of prudent and efficient management of the utility business.

67. OPUCN would remain at risk for:

    a. In year revenue variances from forecast. (Under a one mid-term adjustment model, the revenue variances to OPUCN's account would cover a longer period.)

    b. 58% ($44 million) of its capital investment budget (comprised of system renewal, MS-9, system expansion and general plant).

    c. 100% of its OM&A budget ($64.5 million, which includes donations of $0.2 and $0.8 for property taxes which are reported separately but which are also at risk).

[15] Exhibit 10, Tab D, page 2, in particular second last paragraph.

68. SEC suggests[16], though does not really argue (and, indeed, provides no evidence in support of the point), that the risk mitigating adjustments proposed by OPUCN should result in a lower return on equity from that determined by the Board to be appropriate for an Ontario electricity distributor. This suggestion fails to consider the nature of the risks for which OPUCN proposes to adjust. These risks are material, wholly external to the scope of OPUCN's business and completely unpredictable. Indeed, it could be more fairly suggested that absent adjustment for these factors during the extended rate plan period, OPUCN's ROE should be <u>increased</u> to recognize a significantly higher level of business risk facing OPUCN than the Board's ROE assessment is premised on.

69. As noted above, OPUCN has considered the increased risk resulting from one mid-term review/adjustment process, and is prepared to accept that risk if the Board concludes such an approach better responds, in OPUCN's circumstances, to the spirit and intent of the *RRFE*.

Reversion to 4th Generation IRM with capital modules

70. The parties all argue that OPUCN should address its two largest capital expenditure requirements; MS-9 and regional planning investments (including its contributions to HONI) through capital modules. If this is done, it is argued, OPUCN can simply be slotted back into 4th generation IRM.

71. Even if such an approach were available, the evidence is that it would not be sufficient to provide OPUCN with a reasonable opportunity to recover its costs, including its cost of capital.

72. SEC produced, and other parties have cited in argument, an analysis which presents a partial list of Ontario distributors who, in aggregate, exhibit the same capex:depreciation factor as OPUCN, <u>without</u> MS-9 and regional planning investments, and who are on 4th Generation Price Cap. SEC posits that this

[16] SEC Argument, paragraph 1.2.3.

"analysis" demonstrates that OPUCN can be on 4th Generation Price Cap as well.[17]

73. OPUCN does not know how each of those 4th Generation Price Cap distributors included by SEC in its calculations is funding its capital requirements. SEC has not presented that information, and probably doesn't know either.

74. What OPUCN does know is that it cannot fund its capital investment requirements, even without the regional planning and municipal substation investment requirements, at a rate more than twice that of revenue on account of depreciation.

75. At page 7 of its Argument SEC presented a *Normalized Capital Additions/Depreciation Ratio Summary* for OPUCN. SEC used depreciation expenses which included amortization of deferred charges (the result of an IRFR adjustment) unrelated to capital expenditures. Correct depreciation amounts are found in the Board's model - OPUCN_Chapter 2_Appendicies_for 2015 to 2019_Run 4_xlsm_20150623, Tabs beginning with App.2-BA2.

76. The corrected data indicates that for the years 2015 through 2019, OPUCN's forecast average capital expenditure to depreciation ratio without MS-9 and regional planning expenditures is 2.08, not the 2.02 presented by SEC.

77. SEC argues that this capital expenditure to depreciation ratio is lower than that experience by OPUCN since its 2012 rebasing application. That is true, but ignores the fact that OPUCN under earned in each of 2013 and 2014 by approximately 300 basis points.

78. SEC goes on to contend that this shortfall in depreciation expense relative to capital investment requirement is "normal", and cites data from other distributors who have recently filed for rebasing in advance of 4th Generation IRM rate plans and who have reported similar capital expenditure to depreciation ratios.

[17] SEC paragraphs 2.3.2 through 2.3.5.

79. The 2013 filers, for 2014 rates, could technically file for Custom IR, but given that this option was only available in October, 2012, and these distributors filed applications in the first half of 2013, practically speaking there was limited if any opportunity for them to properly consider the Custom IR option.

80. In considering the 2014 and 2015 filers, OPUCN first notes that SEC's data for Festival Hydro should be adjusted (included in their planned capital expenditures is a TS costing $14 million which should similarly be removed for proper comparison in this case [Decision and Order, page 70]), resulting in a corrected capital expenditure to depreciation ratio of 1.09. The corrected simple average of these LDCs who chose not to file Custom IR applications is 1.914, which is lower than OPUCN's forecast average 2.08 ratio.

81. OPUCN further notes that SEC compares OEB Yearbook data, which reports gross capital expenditures, with OPUCN's net capital expenditure data. Using OPUCN's gross capital expenditure data reported by OPUCN in the OEB's 2013 Yearbook, OPUCN's gross capital expenditure to depreciation ratio for 2013 was 3.4[18].

82. Upon comparing OPUCN's gross capital expenditures to depreciation as reported in the OEB's 2013 Yearbook of 3.4 to SEC's *industry average* for capital additions to depreciation ratio of 2.4, OPUCN's ratio is significantly higher (not lower) than the industry average.

83. Further, SEC's analysis did not reference Horizon, with whose Custom IR settlement SEC and all of the other intervenors in this application agreed, and whose capital expenditure to depreciation ratio for the same 2015-19 period averages 1.9 (see the Horizon Settlement Agreement, Appendix C), which is significantly lower than OPUCN's forecast ratio.

84. Other distributors not considered by SEC who have also filed Custom IR applications are:

[18] $12,482,700/$3,652,144.

Distributor	Average Capital Expenditure to Depreciation Ratio
Powerstream	2.3
Ottawa*	2.0
Kingston	2.0

* After removing Facilities Project for $25.3 million which could be applied for under an ACM.

85. In addition to considering the corrected and more complete data set as set out above, it is appropriate to consider what this capital expenditure to depreciation ratio represents.

86. Depreciation expense represents the "using up" of an asset, such that when the asset reaches the end of its useful life and its value has been used up, its cost recovered.

87. The depreciation expense in base rates allows for replacement of existing assets as they are used up, and applying an inflation factor to base rates (including the depreciation expense) and assuming moderate overall cost efficiencies allows for expansion of the distribution system at a moderate pace, in a "steady state" growth situation.

88. In OPUCN's case, even without MS-9 and regional planning capital expenditure requirements, the growth in assets required to meet system access, system service and system reliability requirements exceeds depreciation expense by a factor of more than 2. This reflects requirements for both significant system renewal and investments to meet significant growth and associated (asset relocation) requirements. This decidedly non-steady-state growth in rate base cannot be funded from depreciation on existing assets. (This was presumably Horizon's conclusion as well, though it's capital requirements were reportedly primarily driven by system renewal requirements, without the significant growth facing OPUCN in addition.)

89. In the result, depreciation on OPUCN's existing assets is insufficient (by more than half) to fund capital expenditure requirements over the plan term from 2015-19.

90. Further, as detailed in OPUCN's Argument in Chief (paragraphs 21-22), and borne out by comprehensive statistical and external benchmarking, OPUCN is already more efficient than the Board's own productivity model indicates should be expected, relative to other Ontario LDCs. It would not be reasonable to expect that OPUCN could appreciably offset average earnings shortfalls in excess of 300 basis points ($8 million over the rate plan term[19]) through further cost efficiencies.

91. Even if the foregoing analysis assuming that MS-9 and regional planning investment requirements were addressed outside of OPUCN's rate plan was not determinative, the suggestion that OPUCN should rely on capital modules to address significantly large and variable multi-year investments disregards the Board's policy direction otherwise.

92. The Board's capital module policy draws a clear distinction between a cost of service application under the Price Cap IR option (with ACM proposals beyond the test year) on the one hand, and the Custom IR method on the other.[20]

93. The Board states in its refreshed (2014) capital module policy that an ACM is <u>not</u> intended for use by a distributor to address multiple discrete capital projects for each of its rate plan years. MS-9 and regional planning projects represent discrete projects presenting costs in all 5 of OPUCN's rate plan years.

94. The Board specifically instructs applicants to note that *"custom approaches to rate-setting should be addressed through selecting the Custom IR option, not by customizing an ACM or ICM proposal"*.

[19] Exhibit J2.8, OPUCN Argument in Chief, paragraph 20.
[20] EB-2014-0219 *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014, page 14.

95. The depreciation analysis presented in the Board's policy as cited in SEC's Argument[21] culminates in an example which concludes that, under current price cap parameters, a gap in excess of 1.7 times depreciation warrants incremental funding (see page 21 of that policy). As noted above, OPUCN's gap is in excess of 2 times depreciation on average during the proposed rate plan term, even without MS-9 and regional planning expenses.

96. Given the number of capital projects driven by the forecast growth and development in the Oshawa area (new connections and associated expansions and plant relocations, as well as MS-9 and regional planning), OPUCN determined it appropriate to follow the Board's policy instructions, and present a Custom IR application, rather than a price cap application with a number of ACMs structured to address a number of discrete capital projects occurring throughout the plan term.

97. Indeed, in presenting its application the way it has, OPUCN has been transparent regarding its capital investment requirements, and its expectations for rates over the plan period. OPUCN submits that this is preferable, and fairer for customers, to carving out, up front, multiple forecast capital projects for "add on" treatment outside of rates.

98. OPUCN notes that parties in this case to have complained about the "regulatory burden" of OPUCN's proposal to revisit certain elements of its rates every year, yet at the same time to advocate that OPUCN bring two (or more) capital module applications forward for separate determination. On the assumption that these parties would request much of the same supporting information in support of those applications as has been provided in support of this application, OPUCN does not see the prospect of decreased regulatory burden under such an approach, even if it were available.

[21] SEC Argument paragraph 3.3.4, footnote 19.

99. The parties also ignore the risk to OPUCN in deferring these capital investment requirement issues for determination in a separate, later proceeding, rather than in the full context presented in this proceeding.

100. Rather than planning to be back before the Board during the rate plan period with an “off ramp” application for review, or with one or more capital module applications (which would require rehashing much of the record in this proceeding), or accepting chronic and material under earnings (as it faced in 2013 and 2014), OPUCN reviewed its rate setting options, and concluded that the most transparent, and the only reasonable, of the 3 available mechanisms for it to set its rates for the period 2015 and beyond was through a Custom IR application.

101. There is no evidence to support SEC’s contention that because some other distributors can fund capital expense even with depreciation at half the required rate, OPUCN can as well.

102. In fact, the evidence before the Board in <u>this</u> case is clear and quite the opposite; OPUCN is already highly efficient compared to its peers as benchmarking has demonstrated, and it has not padded its budgets.

103. In contrast to SEC’s indirect, “back of the envelope” analysis, the <u>direct</u> and highly detailed evidence before this Hearing Panel reveals that it is neither realistic nor reasonable to expect OPUCN to find additional savings to fund a capital expenditure/depreciation revenue gap over the 2015-19 period.

Customer Engagement

104. OPUCN has been criticized by the parties for not seeking its customers’ endorsement for its proposed investments.

105. OPUCN has filed evidence in the form of customer surveys, which validate that customer’s value reliability and investments in outage occurrence and duration reduction. This evidence validates, from the perspective of customers, the

proposed investment in an outage management system and certain, paced, "smarter grid" technology to enhance outage management and restoration capabilities, and enable OPUCN to better communicate outage status to its customers.

106. A full discussion of OPUCN's customer engagement efforts is provided in Exhibit 1, Tab D, which in addition to the customer surveys described includes obtaining feedback through customer service interfaces and OPUCN's efforts to provide information to customers.

107. OPUCN has acknowledged that its customer engagement program merits more attention. One of the new hires planned by OPUCN is precisely to facilitate a more robust customer engagement program.[22]

108. OPUCN submits that:

   a. It has made diligent efforts to ensure that its DS Plan includes investments to enable provision of *"services [that] are provided in a manner that responds to identified customer preferences"*.[23]

   b. While acknowledging that its customer engagement program is a *"work in progress"*, it has proposed continuing efforts and investments in this area.

   c. It has brought forward a proposal for rates that continue, and commit to, a pattern of continued cost efficiency while maintaining and enhancing service reliability.

109. For the purposes of this application, it is respectfully submitted that OPUCN has demonstrated a genuine consideration of the stated preferences of its customers in developing and validating its proposed Capital Investment Program.

Benchmarking

110. As far as OPUCN is aware, it is the first, and to date only, distributor which has provided comprehensive external benchmarking of its proposed rate plan costs.

[22] Transcript Volume 2, page 160.
[23] SEC Final Argument, paragraph 3.5.2, citing the *RRFE* Report at page 2.

111. Heeding the Board's explicit directions, OPUCN retained Pacific Economics Group LLC (PEG) to benchmark OPUCN's proposed costs. OPUCN retained PEG to utilize the same econometric benchmarking model developed for the Board's own use in benchmarking and setting rates for Ontario electricity distributors. PEG undertook an econometric total factor productivity analysis to determine the efficiency embedded in OPUCN's forecast plan period costs. PEGs analysis validates that OPUCN's forecast costs are lower than the costs that would be predicted for OPUCN based on the same modelling on which the Board has relied on through multiple generations of incentive regulation of Ontario's electricity distributors.

112. As detailed in OPUCN's Argument in Chief (paragraphs 74-76) PEG's analysis determined that OPUCN's forecast OM&A and total factor productivity trends are well above the average historical trends for Ontario electricity distributors, and increase over the plan term. PEG's analysis indicates an implicit stretch factor of 0.87 in OPUCN's requested revenue requirement, which exceeds the default Price Cap methodology stretch factor by 0.66%.[24]

113. The intervenors have criticized PEGs benchmarking as:

a. Comparing "apples" (historical productivity trends) with "oranges" (forecast productivity for OPUCN).

b. Benchmarking OPUCN to itself, rather than to external comparators.

114. First, it is true, but irrelevant, that PEG's analysis uses historical data to evaluate OPUCN's forecast productivity. The historical data is used to build a model, premised on relationships between key cost drivers (customer numbers, customer growth, kilometers of line, demand and energy) and observed costs. The result is a relationship between these drivers and cost outputs which reflects expected cost levels for a given distributor's circumstances. This <u>relationship</u> is derived from historical observations. These <u>relationships</u> were used to predict OPUCN costs based on OPUCN's forecast of these key cost drivers.

[24] Exhibit 10.0-Staff-44.

115. In the result, PEG found that OPUCN’s costs, and thus the revenue requirement requested over the plan period, reflect efficiencies which are superior to those predicted by the real world relationships between cost drivers and observed, actual Ontario distributor costs.

116. OPUCN submits that these observed, real world relationships are a more sound basis for evaluation of OPUCN’s relative cost efficiency than would result from comparing OPUCN’s forecasts to forecasts from other electricity distributors, even if such forecasts were readily available and comparable (which they are not).

117. Second, in respect of the criticism that PEGs work compares OPUCN’s forecast costs to itself, at one level this is just wrong. PEGs work uses the same econometric model developed for the OEB in order to compare the relative cost efficiency of Ontario’s electricity distributors one to the others. The model incorporates cost performance observed for each included distributor to derive expected cost performance for a given level of inputs (the main drivers of electricity distribution costs). In other words, the model has been used to compare OPUCN’s forecast costs to the actual historical costs of other Ontario electricity distributors all “normalized” for a given level of OPUCN outputs (customer numbers, customer growth, kilometers of line, demand and energy). This is true, external benchmarking.

118. Parties may, however, be making a different point. The point may be that the efficiencies demonstrated by PEGs modelling of OPUCN’s forecast costs for OPUCN’s expected outputs only obtain if those expected outputs are in fact realized. Thus if load growth over the entire period is in fact 1.5% rather than the 3% forecast by OPUCN and there are significantly fewer customers at the end of the plan period, and fewer kilometers of line and units of demand and energy as a result, then the efficiencies realized by OPUCN at the end of the day would be lower for the same forecast level of costs incurred (and recovered in rates).

119. This is mathematically true. It does not invalidate the efficiencies in OPUCN's forecasts, given the legitimate and supported expectations regarding the activity levels and associated costs required for OPUCN to deliver reliable and accessible electricity distribution service to its customers over the rate plan term. It does imply, however, that OPUCN's actual efficiency, at the end of the day, may be lower than predicted, even with rates locked in at the superior efficiency level forecast. Of course, OPUCN's actual efficiency level could be higher than predicted as well, if customer numbers and/or kilometers of line at the end of the plan term exceed forecast.

120. It is always true in setting rates on a forward test year basis that costs must be set with respect to expectations of required activity levels. There is no other way to set costs prospectively.

121. Further, OPUCN has proposed that net new customer connection costs, plant relocation costs and (as confirmed below) system renewal costs be subject to variance and true up at the end of the plan period. If growth is lower than expected, then revenue collected on account of costs not incurred in extending service to, and connecting, new customers would be credited back to ratepayers.

122. The earnings sharing mechanism accepted by OPUCN as flowing from the mid-term review model and associated load forecast adjustment for its Custom IR also address this issue.

123. OEB Staff has also attempted to address this concern by proposing a symmetrical efficiency carryover mechanism that would be keyed off of OPUCN's realized efficiency levels, rather than ROE. Staff's proposed incentive reward/penalty mechanism would be applied by comparing OPUCN's actual cost/output efficiency results at the end of the plan period against the efficiency predicted in the PEG study filed in support of this application.

124. OPUCN submits that the proposal has not been fully articulated or tested at this point. Further, it is not without potential complexity.

125. OPUCN submits that there is insufficient evidence on the record in this proceeding to determine the appropriateness and mechanics of this mechanism now. However, OPUCN agrees that the proposal merits further consideration.

126. OPUCN submits that if the Board agrees, it could direct OPUCN to consult with Board Staff and interested parties, and report back to the Board prior to the end of the plan period on whether such a mechanism could, and should, be applied at the end of the plan period, in lieu of OPUCN's proposed Total Cost Efficiency Carryover Mechanism (TCECM).

127. OPUCN indicated in its Argument in Chief that, to address concerns that its proposed TCECM was not appropriately focussed on mitigating the disincentive for end of period efficiencies, this incentive could be "focussed on" (i.e. applied only to) the last 2 years of is proposed plan period. In consideration of the arguments advanced by Board Staff regarding an efficiency incentive based on actual productivity, OPUCN would be prepared to accept deferral to a later date of determination of an appropriate efficiency carryover mechanism for application in the later years of OPUCN's Custom IR rate plan. Such a determination could be incorporated in a later within-plan term rate adjustment application (either an annual adjustment application or a mid-term review application, depending on the Board's determination of this application).

128. OPUCN submits that consideration of the applicability of the "efficiency adjustment" mechanism proposed by Energy Probe should also be considered as part of the foregoing consultation and review.

Incentives

129. As submitted above, incentives are already inherent in any multi-year rate plan which fixes rates in advance. This is the essential nature of this form of incentive rate making.

130. That inherent incentive for efficiency is sharpened when, as in the case of OPUCN, the rates are set at a level that embed superior efficiencies, which OPUCN has evidenced its proposed rates do.

TCECM

131. To further incent continuous improvement. OPUCN has proposed an efficiency carryover mechanism (ECM). OPUCN's proposed TCECM is addressed at paragraphs 85-89 of its Argument in Chief.

132. Parties have expressed concern that OPUCN's TCECM is not sufficiently focussed on the later years of its proposed Custom IR plan period, and that ROE is not an appropriate basis upon which to measure sustainable efficiencies.

133. Board Staff has proposed, but as yet not fully articulated, a productivity measured efficiency carryover mechanism. While not without merit, there is little, if any, evidence on the record supporting the applicability of such a mechanism to OPUCN.

134. OPUCN continues to believe that its proposed TCECM, as more fully articulated through the hearing and summarized in its Argument in Chief (to include weather normalization, to include an onus on OPUCN to demonstrate sustainable post rate plan period efficiencies, and, if favoured by the Board, to apply only to the last two years of OPUCN's proposed 5 year rate plan period), is an appropriate ECM for the Board to adopt and apply in this case.

135. In the alternative, should the Board be persuaded by others that OPUCN's proposed ECM requires more work, it could direct deferral of determination of an appropriate ECM to a future rate adjustment review, pending further discussion between OPUCN, Board Staff and interested parties.

CCIEIM

136. SEC has endorsed the intentions behind OPUCN's proposed Capital Cost Investment Efficiency Incentive Mechanism (CCIEIM), though has expressed concern with some of the details.

137. One of the concerns expressed by parties in respect of the proposed CCIEIM is that the updated MS-9 costs have not been benchmarked at all. This is true.

138. As initially scoped, based on the then current status of the regional planning process, the MS-9 project consisted of a $7 million station and $2 million for overhead feeders to the station.

139. Given the evolution of the regional plan, OPUCN had to update its forecast for the overhead feeders for MS-9 from $2 million to $7.5 million. This incremental $5.5 million has not been subject to benchmarking.

140. To address this concern, OPUCN proposes to remove the overhead feeders portion of the MS-9 project from CCIEIM treatment.

141. The $7 million cost of the station itself has been benchmarked by NBM Engineering, and demonstrated to be forecast at a lower total cost than NBM predicts based on the scope of the project. OPUCN proposes to subject this part of the MS-9 project, together with its benchmarked system renewal program forecast, to incentive treatment under the proposed CCIEIM.

142. Some parties have asked why the Board should incent what the utility should be doing anyway. Why, then, do we need incentive regulation at all? The point raised ignores decades of work in many jurisdictions on incentive regulation, intended (to quote from the Board's recent Hydro One decision – page 14) to *"incent behaviour similar to that seen in a commercially-oriented, consumer market-driven companies"*.

ESM

143. OPUCN did not propose an earning sharing mechanism (ESM) in its initial application, for the reasons set out at paragraph 95 of its Argument in Chief.

144. OPUCN has indicated that it can operate with an ESM if the Board so directs.[25]

145. As outlined below, if the Board favours a one mid-term review model for OPUCN's Custom IR plan, OPUCN would propose adjustment of its load forecast in years 2015, 2016 and 2017 to align better with historical (including year to date observed) customer additions. This would address OPUCN's revenue risk resulting from the City of Oshawa's ambitious growth plans not materializing. In this event, to rebalance the allocation of risk, addition of an ESM would protect ratepayers should growth between now and the mid-term review accelerate as predicted by the City and local developers.

Reporting/Metrics

146. Parties have criticized OPUCN's proposed plan period metrics as insufficient. Parties have also been critical that there is no proposed consequence for OPUCN failing to meet those metrics which it has proposed.

147. OPUCN's initial application described its plan period reporting proposal (Exhibit 10, Tab E), as summarized in Argument in Chief (paragraph 97). OPUCN did not initially propose any evaluation metrics.

148. At the technical conference (see Transcript TC 1, pages 20 through 46) there was much discussion about metrics. Review of the transcript of that discussion indicates that parties were very open to proposals from OPUCN of whatever metrics it considered appropriate, and relevant to its business and DS Plan implementation. Specifically included among the suggestions were metrics taken from OPUCN's OEB Scorecard against which it already reports, and metrics related to main system outage causes.

[25] Argument in Chief, paragraph 96.

149. OPUCN's impression following these discussions is that parties did not have a strong view on which metrics would be appropriate, but rather were more interested in OPUCN's proposals for some appropriate metrics.

150. OPUCN proceeded to propose specific metrics for evaluation of its plan period performance, as set out in Exhibit J1.3, and described in its Argument in Chief (paragraphs 98-103):

a. Considering that approximately 50% of its Capital Investment Plan for the proposed Custom IR Plan period relates to system renewal investments, OPUCN proposed a metric to measure improvement in outages resulting from the two primary outage causes; foreign interference and porcelain equipment failure. As noted in Argument in Chief, equipment to address each of these primary outage causes is to be incorporated in OPUCN's system renewal program. Thus tracking outages resulting from these causes should demonstrate not only better performance in respect of these outage causes, but also progress of the system renewal investment program.

b. OPUCN has also acknowledged[26] that it expects to be evaluated on the basis of its progress against its detailed (project by project) Distribution System Plan, annual reporting of which has been proposed.

c. OPUCN has also committed to maintaining 2014 performance levels as reported on its OEB Scorecard and 2014 OEB service quality requirements.

151. Having heard from parties that the precise form of metric was not of great concern, rather a reasonable proposal from OPUCN would be welcome, and having proceeded to propose what it feels are reasonable metrics, including with reference to both its OEB Scorecard and its main outage causes, as specifically suggested by parties at the Technical Conference, OPUCN now feels a bit "sandbagged" in being roundly criticized for having proposed insufficient metrics.

152. OPUCN notes that Horizon's commitment of compliance with OEB reporting was deemed by intervenors, and accepted by the Board, to be sufficient to

[26] Argument in Chief, paragraph 101.

demonstrate whether planned outcomes were being achieved.[27] OPUCN's proposal goes well beyond that commitment.

153. Energy Probe has submitted that *"there does not appear to be any reporting on capital projects outside of the CCIEIM"*, and argued that OPUCN should be directed to report annually on actual results for the previous year and provide variance analysis from Board approved figures.

154. OPUCN refers Energy Probe, and others, to the commitment set out in its application[28] to do just that, in significant detail as articulated in OPUCN's prefiled evidence. Included in this commitment is OPUCN's commitment to report annually against its detailed Distribution System Plan program in each of the system access, system renewal, system service and general plant categories, including providing updated variance and forecast amounts, with explanations.

155. Review of OPUCN's Distribution System Plan reveals extremely detailed, project by project, identification and costing, by project category (see Exhibit 2, Tab B, Schedule 7, and Attachments A trough I thereto). It is against these schedules that OPUCN would report annually, resulting in a fully transparent record of progress against its approved plan.

156. OPUCN notes that concern has been expressed that OPUCN's proposed outage metric (foreign interference and porcelain equipment failure) engages only $1 million of its capital spending program. Mr. Labricciosa clarified in testimony[29] that this is the cost of the specific squirrel guard and porcelain replacing equipment to be installed by OPUCN. However, as noted above, these installations are part of OPUCN's larger system renewal program, and progress on these installations, and attendant outage reductions, will reflect progress on that larger system renewal program.

[27] EB-2014-0002 Settlement Agreement, page 28.
[28] Exhibit 10, Tab E, page 2.
[29] Transcript Volume 3, page 161, line 26 to page 162, line 27.

157. A number of Arguments have criticized OPUCN for not proposing any penalties for failure to meet its proposed metrics.

158. No party, however, had any suggestion for what such consequences might properly be.

159. No suggestions were put to OPUCN at any time, either through discoveries or at the oral proceeding.

160. OPUCN is not aware of any other instance in which Ontario distributors are subject to penalties for failure to realize target metrics.

161. Imposing some sort of penalty on OPUCN for failure to meet its proposed metrics would be new policy for the OEB. There is no evidence in this case upon which to base application of such a new policy to OPUCN at the present time.

162. Absent more specific proposals there is nothing more for OPUCN to respond to on this topic, save to urge the Board to reject them for lack of specificity and supporting evidence, if not out of basic fairness to OPUCN.

Alternative Rate Plan Approach: One Mid-Term Review/Adjustment

163. OPUCN accepts that replacement of its proposed annual rate adjustment proposal with one, pre-scoped mid-term review might be a better approach to Custom IR in the current circumstances, and is one that it can effectively operate under.

164. In this event, as detailed in Exhibit J2.4 and addressed in OPUCN’s Argument in Chief (paragraphs 173-175):

a. Forecast growth, which OPUCN has already adjusted for 2015 to 1.5% based on year to date information, should be similarly adjusted for 2016 and 2017. The intervenor arguments that OPUCN should be held to its “best” forecast of 3% load forecast completely disregards the risks therein inherent to OPUCN, in the atypical growth uncertainties which currently obtain in Oshawa.

b. An ESM could be implemented, which would protect ratepayers from revenues to OPUCN resulting from higher than forecast (1.5%) growth in these plan years.

165. Annual cost of capital updates would be relatively mechanical, and should continue to be applied annually, as generally accepted by the parties.

166. OPUCN proposed in its Argument in Chief (paragraph 173) that in the event of adoption of a mid-term adjustment model, it would propose to adopt a cost of power forecast (for the purposes of calculation of working capital) as indicated in the trend analysis provided in the pre-filed evidence[30], subject to mid-term review. Energy Probe has endorsed an annual cost of power adjustment based on the Board's published cost of power forecast. OPUCN agrees that this would result in a mechanical adjustment that could conveniently be implemented annually at the same time as the generally accepted cost of capital adjustment, and endorses this approach. This would preclude either OPUCN's shareholder or its customers from assuming risk associated with unpredictable Ontario power prices.

167. As indicated in Argument In Chief (paragraph 175), OPUCN accepts additional capital expenditure "ring fencing" through the addition of a capital expenditure variance account, to capture revenue requirement associated with system renewal projects not implemented during the plan term. This account would work in tandem with:

a. The proposed CCIEIM, which would capture variances in costs on system renewal projects that <u>are</u> implemented over the plan term, for incentive treatment as described in the evidence and Argument in Chief.

b. The variance accounts already proposed for costs related to third party driven relocation projects (see Exhibit 2, Tab B, Schedule 7, Attachments A-C), and regional planning costs.

[30] Exhibit 2, Tab A, pages 45 *et seq.*

168. OPUCN has also noted concerns reflected in the parties' arguments regarding OPUCN's position that it does not intend, in the annual update process proposed, to redo its cost allocation model every time that rates are updated.

169. In the event that the Board adopts one mid-term review, then OPUCN accepts that it would be appropriate for OPUCN to re-run its cost allocation in the event that it proposes to change rates for the period following the mid-term review.

ISSUE 2: DISTRIBUTION SYSTEM PLAN AND CAPITAL EXPENDITURES

Net New Connection Costs

170. Board Staff has argued for reduction of OPUCN's forecast net new connection costs in the amount of $400,000 in 2015, in relation to OPUCN adjusting its forecast customer connection growth from 3% to 1.5%. A number of interveners agreed with Board Staff's position including EP and GOCC.

171. As indicated in its Argument in Chief (paragraph 136), OPUCN agrees with this adjustment, in the event of a load forecast adjustment. The revenue requirement impact of such an adjustment in each year of the plan is provided in Exhibit J2. (page 6). OPUCN has already adjusted its 2015 cost forecast in this respect, in line with its adjusted 2015 load forecast as filed.

172. For the reasons provided in Argument in Chief (paragraphs 129-139 and 173-174), if the Board adopts a one mid-term review model for OPUCN's proposed Custom IR plan, OPUCN believes that the 2017 and 2018 load forecast should be adjusted to 1.5%, and agrees that it would also adjust net new connection cost forecasts for these years as it has for 2015.

173. In this event, as incremental connection costs could be funded from incremental revenues due to un-forecasted growth, and if the Board directs an ESM as OPUCN has suggested under this model, the initially proposed variance treatment around net new connection costs could be eliminated.

Hydro One Contributions

174. Staff and GOCC have also argued for a reduction in OPUCN's forecast for its share of costs contributions for HONI's proposal to build the Enfield TS.

175. The premise for this argument is that Hydro One has analyzed 3 options for Enfield, and has, on a preliminary basis, recommended an option which has a cost lower by $2 million than the cost included by OPUCN in its forecast capital

contribution. This less expensive option provides for 6 feeders (3 for OPUCN), whereas OPUCN's preferred option provides for 8 feeders (4 for OPUCN).

176. The three options and HONI's reasons for its preferred choice are discussed in HONI's regional planning report entitled, *"Final – Local Planning Report"* issued on May 15, 2015 and included in Exhibit TC2.9 Updated.

177. OPUCN's current view is that the 8 feeder (4 for OPUCN) option is, in the long-run, the more cost effective, however a full analysis has not yet been completed.

178. For the purposes of this application, OPUCN agrees that, with the inclusion in OPUCN's approved rate plan of an account to capture the variance between actual HONI contributions and the forecast of contributions included in rates, reduction of Board Staff's proposal to reduce forecast HONI contribution costs by $2 million would be appropriate.

General Increase in Fixed Assets

179. Parties have expressed concern at the proposed rate of increase in OPUCN's next fixed assets.

180. The evidence indicates that[31]:

a. OPUCN currently has among the lowest net fixed asset per customer ratio from among its peers. (Argument in Chief, paragraph 70).

b. OPUCN's forecast 2019 net fixed assets per customer ratio remains lower than average comparable LDCs for 2013.

181. Relative to 2013, OPUCN forecasts an increase by 2019 in its net fixed assets per customer by (depending on the final load forecast) between 39% and 53%, to between approximately $2,000 and $2,200.

[31] Exhibit 1.0-Staff-1, pages 5-6; Exhibit 10, Tab C, pages 2-5 and 8-10.

182. By comparison, OPUCN's peers average $2,020 in net fixed assets per customer, and the industry averages $3,080 in net fixed assets per customer, both in 2013.

183. OPUCN finds it ironic that, on the one hand, parties have criticized OPUCN for not benchmarking against other distributors (which criticism OPUCN refutes in this Reply Argument), and on the other hand disregard the value of such comparisons in this instance.

184. OPUCN's forecast increase in net fixed assets per customer over the plan will bring OPUCN into line with the current capital intensity of its peers, and the sector at large.

185. Important context for OPUCN's proposed increase in its net fixed assets is the evidence in OPUCN's 2011 cost of service application. In that case, not only did OPUCN identify the need for an increased level of capital expenditure going forward, OPUCN was strongly encouraged to increase its net fixed assets by the intervenors.[32]

186. In the transcript from presentation to the Board of the settlement agreement in OPUCN's 2012 cost of service application (EB-2011-0073), Mr. Shepherd speaking for SEC emphasized the following:

> *This particular utility, for – two times in the past had a budget that it significantly under spent. So the ratepayers are concerned that investment is needed and should be made.* [33]
>
> *....*
>
> *So the ratepayers are concerned that this is a utility that does need investment. You can see from their statistics that their infrastructure needs some spending. And the ratepayers want them to do that, but don't want to provide a budget to do that and then have what happened in the past, a reprioritization that results in the spending not getting done....*[34]

[32] See Exhibit 2, Tab A, page 9 herein.
[33] EB-2011-0073, Transcript Volume 1, December 6, 2011, page 9, lines 21 through 24.
[34] Ibid, page 12, lines 12 through 18.

187. Following Mr. Shepherd's statements, Mr. Martin, speaking for OPUCN, added the following:

> *If I can add to that, we do, as Mr. Shepherd has mentioned – we – statistically we are underinvested in our fixed assets.*
>
> *We have identified that. In the past five year we've averaged approximately $5 million of capital spend.*
>
> *We have, in our next five years, identified that we need to spend on average 10 million.*
>
> *So they recognize that we have a fairly aggressive capital spend plan, in addition to what we've been spending on our track record.*
>
> *So, you know, to acknowledge that and to identify the fact that we do need the money, we've kind of settled on this arrangement to ensure that Oshawa, in fact, does spend the money, but we're happy to do it and we have identified the additional capital requirements.*[35]

188. Coincidentally, review the subsequent pages of that transcript reveal a discussion of a future requirement for a substation, which was deferred from 2009 and 2010 *"because of things that occurred in Oshawa"*. That was the reason for the historical capital under spend prior to 2012, and the reason why intervenors were so keen on having OPUCN start to spend. Mr. Martin went on to identify existing substation and transformer upgrade work in lieu of a new substation in the coming years (2013 through 2015) which OPUCN would invest in. These are precisely the investments which OPUCN has since made, and which have caused a material increase in its fixed asset per customer ratio between 2013 and now, which Board Staff and others express concern about.

189. It is, frankly, a bit frustrating to OPUCN that, in 2012, it was being exhorted by parties to spend more on its infrastructure, it did so, and now it is being criticized for increases in its net fixed assets per customer ratio.

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[35] Ibid, page 12, line 27 through page 13, line 14.

190. This is particularly frustrating given that even with its significant current and forecast asset investments, OPUCN will still be as or more efficient from a capital investment perspective in 2019 as its peers were in 2013!

191. In summary on this point, consideration of increases in net fixed assets without considering the starting or ending point for those investments is somewhat misguided.

192. As detailed in its Argument in Chief (paragraphs 108-115), in the current application, OPUCN has provided a comprehensive Distribution System Plan (DS Plan), supported by external review and benchmarking, which presents full detail of, and justification for, its proposed capital expenditures. OEB Staff has acknowledged that OPUCN's DS Plan meets the OEB's expectations for such a plan as envisaged by the *RRFE*.[36]

193. Further, consideration of the nature of OPUCN's proposed capital expenditures is important context as well. OPUCN submits that its proposed expenditures are generally non-discretionary. In particular:

a. A significant amount of proposed capital expenditure is driven by the need, as the provider of an essential service, to respond to significant development and expansion activities being pursued by third parties in OPUCN's service territory. Planned expenditures in the System Access category are $13.9 million, required for projects to meet customer service obligations. These projects include customer service requests for expansions and connections, metering and other service obligations. OPUCN has already agreed to reduce forecast connection costs included in this category in accordance with reductions to its load forecast. As noted above, OPUCN does not believe it can reduce planned investments in this category any further while still meeting its obligations to provide electricity service to new customers.

b. Mr. Labricciosa's testimony indicates that the ability of OPUCN's distribution system to reliably serve demand is at or near capacity.[37] Planned investments in the System Service category are $32.1 million, of which $29.1 million is for the MS-9 distribution station and HONI's Enfield TS. As noted above, OPUCN agrees with Staff that reduction of $2 million

[36] OEB Staff Argument, page 23.
[37] Transcript Volume 3, page 158, line 17 – page 159, line 3.

in forecast contributions for Enfield TS are appropriate, provided that variance treatment is afforded.

c. Of the balance in the System Service category, $3.0 million is forecast for investments that are largely related to OPUCN's smart grid initiatives outlined in third-party report prepared by Utiliworks. These investments respond to the Ministry of Energy's desire for LDCs to utilize technology and automation intelligence in an effort to develop a smart grid. The *RRFE* contemplates, indeed mandates, that distributor investment plans address public policy goals.

d. The Asset Condition Assessment and Asset Management Plan developed by Metsco Energy Solutions identifies System Renewal requirements the costs of which total $25.0 million over the plan term to replace or refurbish aging equipment near or at end of life or at risk of failure.

e. General plant which includes investments in tools, vehicles, building and information systems technology equipment that are required to support the safe and reliable operation and maintenance of the distribution system, requires planned expenditures totalling $4.9 million over the plan term.

194. Without considering the specifics of OPUCN's planned capital expenditures, parties have argued that investments could be deferred.

195. Board Staff, VECC and SEC all argue that, considering OPUCN's history of strong reliability, system renewal investments could be deferred. Metsco's detailed Asset Condition Assessment and Asset Management Plan indicates otherwise. None of the parties sought to examine Metsco. Nor was there any examination of OPUCN's witnesses on any specific suggestions for system renewal investment deferral.

196. OPUCN does not believe that it can defer any significant portion of its system renewal investment plan without jeopardizing ongoing reliability, and submits that the evidence supports this believe and there is no evidence indicating otherwise.

197. Parties have asserted that OPUCN's capital investment plans lack sufficient priority and pacing. As noted earlier in this argument, OPUCN has acknowledged earlier that its AIP is a "work in progress", which could, and will, be improved.

198. However, as testified to by Mr Labricciosa[38], the reason that all of the projects listed in the DS Plan have been prioritized for execution during the plan period is because priority has been determined in proposing projects for input into the AIP tool in the first place. The project “funnel” identified by OPUCN generally consists of projects it knows are high priority.

199. Parties further argue that OPUCN has failed to properly pace its projects. None of these arguments refer to any specific projects, though these are all exhaustively set out in the DS Plan and its detailed schedules, with descriptions and dollar figures. Now, OPUCN does not fault intervenors for not pouring over this data, it is not an appropriate role for intervenors to seek to micro-manage the utility. It does, however, fault them for alleging insufficient pacing based on raw mathematical averages alone.

200. Energy Probe, for example, suggests that projects should fit within an annual average of $9.4 million without providing evidence of which projects could be shifted around.

201. As should be evident from the comprehensive nature of the DS Plan and its supporting schedules, the plan has been prepared with a significant amount of thought and effort. That effort takes into consideration a number of factors resulting in a list of projects and detailed schedules for their completion.

202. In developing its DSP, OPUCN has considered its pacing for projects. Mr. Labricciosa addressed this during his testimony as follows[39]:

> *So we pretty much do the condition assessment, risk profile, which sets prioritization and, you know, in there is what I would call the hopper of work that needs to be done.*
>
> *That takes care of the system sort of reliability side.*

[38] Transcript Volume 3, page 74, line 19, *et seq.*
[39] *Ibid*.

It has to be balanced out against two parts, one of which you describe as rates. So there is the notion that in the backdrop, if we do a certain amount of work there is a rate impact attached to it.

The other balancing act is the work resource, the work management that is required to actually undertake the work.

203. In other words, given the drivers for certain projects it is not able to smooth its construction activities as precisely as Energy Probe is suggesting.

204. For example, capital spending in 2015 is forecast at $12.8 million, which is $3.4 million over the simple average calculated by Energy Probe. Consideration of the facts underlying this forecast indicates that in 2015 $3.9 million of the forecast capital investment was constructed in 2014, but not placed into service in 2015 ($2.8 million in system access related to the 407 extension, and $1.1 million for MS14 switch gear in the system renewal category).

205. SEC proposes that OPUCN could accomplish pacing by reducing renewal spending late in the plan when system service expenditures spike, by deferring some system renewal projects to after 2019.

206. OPUCN does not believe it can simply adjust its resources and project scheduling as simply as SEC suggests. System Renewal plans are informed by the Asset Condition Assessment and Asset Management Plan, which reflects a comprehensive review of OPUCN's infrastructure. Significant deviations from this report could put reliability or performance at risk.

207. Concerns regarding forecast capital expenditures based on historical under spending and/or insufficient evidence of efficiencies are all addressed by the third party validation (i.e. "benchmarking") which OPUCN commissioned and filed in support of its DS Plan, as summarized in its Argument in Chief (see paragraph 114.d.).

208. In respect of historical under spending, OPUCN again notes the evidence from its 2012 Cost of Service, as summarized at paragraph 188 above regarding deferral from 2010 and 2011 of what is now its proposed MS-9 distribution

station. OPUCN also notes that not only did it not under spend more recently (in 2013 and 2014), but in fact it significantly under earned (that is, it spent more than it has available to it).

209. Staff has criticized OPUCN's DS Plan expenditure benchmarking on the basis that it is not benchmarked to the cost of other distributors. It is not at all clear to OPUCN how it would do that. What it has done is commission NBM Engineering and Metsco, both experienced utility advisors, to assess its forecast capital budgets. Presumably these engineers developed their own cost estimates based on their experience with other like investments. In both cases, OPUCN's forecast costs are at or below the externally benchmarked costs provided.

210. OPUCN strongly disagrees with Board staff that this benchmarking is in any way deficient.

211. OPUCN further notes that PEG's productivity analysis of OPUCN's capital costs indicates productivity equal to, or better than, Ontario wide electricity historical distributor capital productivity (see paragraph 272, below).

212. Again, none of the parties sought to examine the experts retained by OPUCN to conduct the external benchmarking work.

Working Capital

213. Energy Probe has taken the lead for parties in evaluation of OPUCN's working capital calculations.

214. OPUCN proposed a working capital allowance of 13% of its annual cash expenses. A number of adjustments arising from Mr. Aiken's analysis on behalf of Energy Probe and accepted by OPUCN were summarized in Exhibit J1.1, page 2, and resulted in an updated working capital allowance percentage of 10.02%.

215. Energy Probe's argument seeks further reduction in respect of the calculation of service lag and the calculation of the cost of power expense lead.

216. Service lag is the lag between the provision of service and the date on which the meter read for the service is taken. Following reading of the meter, there is then a billing lag between that date and the date that the customer invoice is issued. There is no dispute between Energy Probe and OPUCN regarding the billing lag.

217. In respect of the service lag, Energy Probe argues that for distributors which bill monthly, which OPUCN does, the service lag is always the mathematical mid-point of the monthly service period, which averages at 15.22 days. The lead/lag study filed by OPUCN in support of its working capital proposal (Exhibit 2, Tab A, Schedule 1) determined the service lag to be 17.44.

218. 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 working capital allowance percentage from 10.02% to approximately 9.37%.

219. Upon review of the lead/lag study and Energy Probe's Argument, OPUCN agrees with Mr. Aiken that the service lag should be 15.22 and the resulting working capital allowance percentage should be reduced to 9.37%.

220. In respect of the cost of power expense lead, there is no dispute that, under OPUCN's current IESO prudential arrangements, it has calculated the expense lead appropriately at 24.64 days. Unlike the adjustments noted above which relate to the lead/lag computations, Mr. Aiken's arguments to increase the cost of power lead and deduct the cost of OPUCN's letter of credit in support of the IESO's prudential require a change to OPUCN's operating procedures.

221. The argument advanced by the parties is that OPUCN should post a higher letter of credit with the IESO, which would result in fewer margin calls. This would in turn increase the length of the expense lead (there would be fewer IESO payments in between IESO invoices) and thus lower the working capital allowance. Energy Probe has calculated a resulting working capital allowance adjustment of 2.04% (an annual revenue requirement impact of approximately $200,000).

222. The arguments also acknowledge that the annual cost to OPUCN of increasing the letter of credit posted with the IESO would be approximately $50,000.

223. Under the OM&A heading of its argument Energy Probe further argues that the annual cost incurred for the letter of credit used by OPUCN to facilitate the prudential arrangement should not be counted in OM&A expense but rather the amount of the letter of credit should be considered notionally as short term debt and cost of the letter of credit should be considered notional interest expense which is already recovered in OPUCN's deemed cost of capital.

224. That is, Energy Probe argues that $200,000 in revenue be removed on account of this change to the working capital allowance, and the offsetting $50,000 cost which Energy Probe acknowledges as incremental does not in fact have to be recovered because it is somehow already included, even though it is not now being incurred, in OPUCN's cost of capital.

225. In other words, Energy Probe argues that this $50,000 incremental expense (plus a pre-existing OM&A expense for the cost of the letter of credit currently in place) simply disappears through the magic of Mr. Aiken's calculations – "poof".

226. That is not, however, how the real world works.

227. First, there is no evidence on the impact to OPUCN of tying up with the IESO the incremental $4-5 million worth of credit advocated by Energy Probe and other parties. Energy Probe has quoted Mr. Martin's testimony[1] in support of the proposition that the interest on such an incremental short term debt is already included in the cost of capital. What Mr. Martin in fact said was:

> *Well, that [$50,000] would be the direct cost of the letter of credit. But there is obviously a cost of tying up that money. We've never taken the consideration of what it costs for the $7.5 million, for example, but in any event there is a weighted average cost of capital for tying up funds, whether it is the 7.5 or the 12.5.*

[1] Transcript Volume 1, pages 123, line 26 – page 124, line 4.

228. This testimony speaks to the implied cost of carrying a deposit in favour of the IESO, in the form of a letter of credit, which is a financial instrument that under accounting rules is not recorded and therefore is an “off balance sheet” financial arrangement between OPUCN, its banker and the IESO. However, such a letter of credit would be tying up additional capital, which would then be unavailable for other uses. For a distributor like OPUCN with significant ongoing capital investment requirements – such as financing a new municipal substation – this has a significant cost.

229. The function of such a deposit is prepayment of the distributor’s cost of power. The IESO does not extend credit to anyone. Prudentials are posted using letters of credit, short term investments or in some cases cash deposits to cover the cost of power, or interim payments (margin calls) are required. In this respect, the letter of credit represents a cash deposit with the IESO. Such a deposit would be considered working capital and would likely eliminate most if not all the cost of power lead used in the calculation of the working capital allowance.

230. That is, if the letter of credit were increased to preclude margin calls, then all power costs would effectively be prepaid and there would be a cost of power lead of 0, significantly increasing calculated working capital requirements.

231. OPUCN is <u>not</u> seeking such treatment for its current prudential posting. On this parameter, OPUCN is sticking with the evidence which it has provided through the Ernst & Young lead/lag study in support of its working capital request.

232. The Board allows distributors to provide evidence to support their working capital allowances because the distributors are required to manage their financial affairs based on their specific needs and financial circumstances.

233. OPUCN currently has the financial capability to manage its account with the IESO under the prudential arrangement it has in place and does not believe it should be forced into a different financial arrangement that it can’t support and does not require at this time.

ISSUE 3: OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

234. Parties have argued for reduction of OPUCN's proposed OM&A budgets. These arguments ignore the evidence that;

   a. OPUCN's proposed OM&A budgets have been externally benchmarked as highly efficient, delivering productivity improvement determined by PEG to be *"well above the average historical trends for Ontario power distributors which we calculated in our recent work for the Board"*[40]; and

   b. 2014 actual OM&A is not an accurate reflection of sustainable operating costs for OPUCN.

235. Despite the foregoing, and despite OPUCN having evidenced an OM&A cost level for 2015 that benchmarks very favourably against comparable Ontario electricity distributors, and despite OPUCN having proposed rates through 2019 which reflect OM&A cost escalation below inflation, intervenors have stuck to their habitual arguments for;

   a. mechanical calculation of test year (in this instance 2015) OM&A based on bridge year (in this case, 2014) actuals; and

   b. formulaic indexing, inclusive of yet additional productivity expectations, for OM&A escalation over the rate plan term.

236. Board Staff's analysis of OPUCN's OM&A cost trend proceeds from 2014 as the "base" year, and concludes that *"OM&A increase for 2015 and 2016 are excessive and not justified by the evidence"*[41]. However, Board Staff does not review any of the evidence on the record regarding 2014 costs.

237. That evidence is that:

   a. Labour represents over 70% of OPUCN's OM&A.[42]

   b. In 2014 OPUCN experienced employee turnover, with delayed filling of those positions. This resulted in lower actual 2014 labour costs than entailed in a full FTE complement.

[40] Exhibit 10, Tab A, page 5.
[41] Board Staff Argument, page 17.
[42] Transcript Volume 3, page 11.

c. In 2014, OPUCN also had 3 employees go on long term disability. While a cost reduction in 2014, these employees will be back, at full cost, during the rate plan period.

238. Using 2014 actual OM&A as a basis for calculating an inflation adjusted predicted 2015 cost is thus not a relevant or useful approach.

239. OPUCN's Mr. Martin noted similar trends in OM&A cost escalation upon rebasing in other recent Ontario Custom IR distribution rate applications:[43]

a. Compared to its last cost of service Board approved test year, Horizon's OM&A increased by 17% to its recently settled and Board approved test year, and 24% to its now approved 2019 rates.

b. Powerstream has applied for 20% increase in its OM&A from its last cost of service to its first test year, 2016, and a 30% increase from its previous cost of service test year to its last test year, 2020.

These figures are both significantly higher than those for OPUCN as lamented by OEB Staff: 6% from its last Board approved cost of service OM&A to it first test year, 2015 and 16% from its last Board approved amount to its requested 2019 OM&A, and this even with growth that Horizon is not addressing.

240. OPUCN has since reviewed other recent cost of service applications, and notes that Algoma had an increase of 29% (16% after adjusting for IFRS) from its previous cost of service application, and Festival Hydro had an increase of 19% from its previous cost of service application.

241. These facts indicate that the need to increase OM&A upon rebasing following a period of rate set under Rate Cap IRM is not unique to OPUCN, and may well be a function of the mechanics of Rate Cap IRM rather than OPUCN's relative efficiency levels.

242. Upon determining the correct starting OM&A, OPUCN has provided its evidence on cost drivers for incremental expenses forecast in 2015 including:

[43] Transcript 3, page 11 *et seq.*

a. The addition of 3 new employees (the equivalent 1.3 FTEs based on hiring schedule in 2015); and

b. An increase in regulatory costs resulting from the cost of this Application.

c. The commencement of succession planning costs (approximately $100,00, including benefits.[44]

243. In respect of 2016 costs, the evidence is that:

a. As noted above, OPUCN has budgeted for 3 incremental employees in 2015 (and for a full year commencing in 2016) to support ongoing and anticipated capital investment activity; a meter technician, a manager of asset management, and a power maintenance electrician. These are all costs driven by OPUCN's Capital Investment Plan, as supported by its comprehensive Distribution System Plan and the associated *Asset Condition Assessment and Asset Management Plan* prepared by Metsco Engineering.

b. OPUCN has also budgeted for a communications subcontractor as of September 2015 (and for a full year in 2016), to support customer communications requirements arising from both forecast customer growth and *RRFE* customer engagement requirements.

c. OPUCN has planned to continue its succession planning activities in 2016, at a cost of approximately $200,000, including benefits. (Succession planning concludes in 2017, at a forecast cost of approximately $30,000, including benefits in that year.)[45]

244. Referring to table 5.2 in Staff's argument, the appropriate average annual OM&A growth rate to consider is that from 20<u>15</u>-19. During this period, OPUCN's revenue request locks in a 2.1% OM&A growth rate, as compared to the average Conference Board of Canada forecast inflation rate for the same period of 2.65%, as cited by Staff (Staff Argument, page 17).

245. Staff recognizes that OPUCN compares favourably in the metric of OM&A cost per customer with its former cohort distributors, and acknowledges that OPUCN's target <u>end of period</u> OM&A cost per customer remains as it was in 2013 at $208, the second lowest in its cohort of 12 distributors and well below the industry

[44] Exhibit K1.2, Appendix 2-JB as reproduced by Energy Probe at page 24 of Exhibit K1.4.
[45] *Ibid*.

average of $295.[46] That is, OPUCN proposes to end its rate plan period with the same 80 FTEs which it starts with in 2015.[47]

246. Staff goes on to note that this metric is sensitive to growth in customer numbers, which is of course true. Using 1.5% customer growth assumption for all years from 2015 on, as did OEB Staff, and using the correct starting point (2015), OPUCN's OM&A per customer forecast for 2019 increases by 2.3%, which is still below the inflation rate for the comparable period of 2.65% (and nowhere near the 10% quoted by staff using the incomplete FTE complement evidenced in 2014).

247. The evidence is that at its forecast 3% customer growth rate, applying the current customers/FTE metric OPUCN plans to avoid 6 FTEs.[48] Even if customer growth were to remain at 1.5% over the plan period, OPUCN would still avoid 3 FTEs, even if it did not adjust its staffing plan in response.

248. Turning to VECC's Argument on OM&A, VECC prepared a table[49] which "indexes" OPUCN's OM&A from its 2012 level (Board approved and actual) through 2015, and concluded that OPUCN's 2015 OM&A request should be reduced by $915,000 from its requested level.

249. VECC mistakenly used OPUCN's 2016 forecast in place of OPUCN's proposed 2015 OM&A. VECC used $12,532,655, which is approximately $480,000 higher than the 2015 OM&A which OPUCN has actually forecast ($12,053,845).

250. With this correction, VECC's derived "implied OM&A reduction" goes down from $915,000 to approximately $435,000.

251. Further adjusting this figure for the incremental (in 2015) regulatory expense associated with OPUCN's application (estimated at $165,054), brings the "implied OM&A reduction" down to about $270,000.

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[46] Staff Argument, page 18.
[47] Exhibit 4, page 46.
[48] Exhibit 1, Tab C, page 33, second last paragraph.
[49] VECC Argument, page 16.

252. Using VECC's starting point, and a corrected forecast OM&A 2015 ending point, the average annual increase in OM&A between 2012 (actual) and 2015 (forecast) is 0.77%, which is significantly less than the annual average increase for the same period using the index devised by VECC. This would include; i) inflation; ii) a "customer growth index" which all parties seem to recognize is a required element of an appropriate calculation; iii) productivity; and iv) a stretch factor.

253. Attached as Appendix A to this Reply Argument is a table modelled on VECC's analysis, as corrected above, but using PEG's methodology for an OM&A cost escalator for OPUCN[50]. PEG's analysis uses a "scale index" (as used in PEG's recent work for the Board). The result of applying PEG's methodology is that OPUCN's forecast 2015 OM&A is $157,000 over that predicted by the analysis.

254. Attached as Appendix B to this Reply Argument are two additional tables, extending the application of VECC's corrected table and PEG's scale index through the proposed rate plan period, for both OPUCN's updated growth forecast and for OEB Staff's proposed 1.5% growth forecast, starting with OPUCN's forecast 2015 OM&A of $12.054 million.

255. The result of pursuing VECC's method of analysis, with corrected inputs and adopting PEG's more scientific methodology is that under OPUCN's forecast growth rate, cumulative <u>efficiencies</u> by the end of the plan period are $2,132,000. Under Board Staff's 1.5% annual growth forecast, OPUCN's cumulative OM&A efficiencies are still $633,000.

256. PEG's own analysis resulted in cumulative efficiencies of $668,953 through the plan period (see Exhibit J2.10, page 5, column I). This analysis applies more current inflation forecasts rather than inflation rates 2 years in arrears as does the OEB's IRM methodology, and also excludes certain OM&A costs (bad debt expense, energy conservation and donations).

[50] Exhibit J2.10.

257. Energy Probe also provided a calculation of OM&A indexed escalation, with a customer growth factor, in Appendix A-2 of its Argument. OPUCN notes a number of errors in this calculation:

a. An incorrect stretch factor for 2013 (Energy Probe used 4%, s/b 3%).

b. An incorrect cost escalator for 2015 (Energy Probe used 0%, s/b 0.67%).

c. Donations were removed in the 2012 starting amount, and should not have been (these totalled approximately $24,000).

d. Regulatory costs associated with this application should be added (approximately $165,000).

258. Correcting for these errors, OPUCN has derived, based on Energy Probe's methodology, a 2015 forecast OM&A of $11,780,000.

259. While this is lower than OPUCN's forecast $12,054,000 2015 OM&A, it is also an incomplete methodology, as it escalates only for customer growth, and does not account for the other relevant inputs identified by PEG; delivery volume, demand and line miles.[51]

260. Applying PEG's more completely derived escalation factor of 2.93% to Energy Probe's analysis results in a 2015 OM&A forecast of $12,100,000, which is <u>higher</u> than OPUCN's forecast 2015 OM&A.

261. What all of this shows is that, under any version of a corrected analysis (PEG's or the OEB's methodology, using a 3% growth forecast or a 1.5% growth forecast), OPUCN's plan period OM&A request already results in material cumulative efficiencies in favour of its customers, relative to a straight indexing approach.

262. In other words, indexing OPUCN's OM&A costs from 2014 through 2019 as suggested in the arguments filed, would actually result in <u>higher</u> rates than OPUCN has requested.

[51] See Exhibit J2.10, page 4, second last paragraph.

263. SEC has suggested that staff turnover should be factored in to lower OPUCN's forecast OM&A. OPUCN disagrees. There is no observable trend at OPUCN for staff turnover. OPUCN did not experience any significant turnover in staff in 2010, 2011, 2012 or 2013. While there was turnover in 2008 and 2009, there is no evidence on the record as to the cause for this turnover, or whether it is likely to repeat, and there is thus no basis to reduce forecast OM&A on this basis.

264. SEC also argues that OPUCN's OM&A forecast should be reduced by the simple average of its previous under spend from Board approved cost of service OM&A in each of 2006, 2009 and 2012.

265. In Exhibit 4, page 21, OPUCN evidenced a $400,000 decrease in post-retirement benefits in 2013 and beyond, resulting from an updated actuarial report.

266. OPUCN's average OM&A "under spend" for 2012, 2013 and 2014 in relation to 2012 Board-approved OM&A of $11,330,870 was $274,098 (or 2.4%). But for the actuarially driven reduction in post-retirement benefits of $400,000 in each of 2013 and 2014, OPUCN would have spent approximately $150,000 <u>more</u> than Board approved OM&A in each of these years.

267. Further, OPUCN under earned in each of 2013 and 2014, and had it spent its entire approved OM&A budget, it simply would have under earned by <u>more</u>.

268. Proper consideration of these facts supports, rather than undermines, OPUCN's request for increased OM&A for 2015.

269. In respect of 2006 and 2008, there is no evidence on the record in this proceeding to explain variances from approved to actual OM&A for these years. In any event, to the extent relevant, these issues would have been considered and incorporated into OPUCN's 2012 Board approved cost of service settlement, which included 2012 OM&A.

270. Energy Probe's argument asserts the proposition, echoed in the arguments of others, that just because OPUCN has relatively low rates, low OM&A costs per

customer, and low net fixed assets per customer, it is not necessarily efficient. As reviewed above, Energy Probe goes on to suggest an OM&A escalation "index" that, properly applied, would result in rates <u>higher</u> than those proposed by OPUCN.

271. Various other analyses reviewed above, properly applied, would lead to this same result.

272. PEG benchmarked OPUCN's forecast costs to cost trends modelled on data from all other Ontario electricity distributors, and this analysis found that OPUCN is, and will remain, highly efficient, particularly in respect of OM&A. Table 6 from PEG's benchmarking report (Exhibit 10, Tab A), reproduced below, illustrates this:

Table 6

Comparison of Productivity Trends

	OPUCN	**Ontario Distributor Averages**	
	2015-2019	**2003-2011**	**2003-2012**
OM&A	2.17%	0.51%	-0.40%
Capital	0.12%	0.01%	-0.26%
Total Factor	0.87%	0.19%	-0.33%

273. This table further illustrates that GOCC's assertion that OPUCN's *"historically low cost is more likely attributable to its low net fixed assets per customer rather than extraordinary efficiency"* is completely wrong. PEG's analysis shows that OPUCN's OM&A productivity trends for the proposed rate plan period remain significantly above those of other Ontario distributors, most markedly so in respect of OPUCN's proposed OM&A.

274. OPUCN does not accept EP's argument to remove the cost of the letter of credit. OPUCN's has provided a more detailed response to this in the working capital allowance section of this Reply Argument.

ISSUE 4: FORECASTS

Load Forecast

275. All of the intervenors have argued that OPUCN should be held to its 3% load growth forecast, as filed.

276. Board Staff, on the other hand, advocates a 1.5% load growth forecast, as better aligned with historical load growth.

277. OPUCN reiterates that its view of an appropriate load forecast is interdependent with the availability of a rate adjustment mechanism to address material changes in load forecast.

278. OPUCN has been clear throughout this proceeding, that while a 3% average annual load growth forecast is its "best" forecast for 2016 through 2019 (2015 having now been adjusted from the as filed forecast of 3% to 1.5% in light of year to date information), given the uncertainties inherent in this forecast and the material impact of manifestation of those uncertainties on its revenues, OPUCN cannot afford to take the risk on a long-term growth forecast of 3%, even if that figure is based on the best information available to OPUCN at the present time. The rationale for this position is set out at paragraphs 127 to 125 of OPUCN's Argument in Chief.

279. OPUCN confirms in this Reply Argument that, in the event that the Board choose to adopt a one mid-term review model for OPUCN's Custom IR rate plan, thus fixing on OPUCN the risk of load growth for 2016 and 2017, a 1.5% load growth forecast would be appropriate. The addition of an ESM and the downward adjustment of net new connection costs all as addressed elsewhere in this Reply Argument would also be appropriate in this event.

280. For the period following such a mid-term review – 2018 and 2019 – OPUCN continues to believe that its 3% load forecast is the "best" forecast based on

information currently available to it, for the reasons evidenced and reviewed in its Argument in Chief.

281. Given its demography and local economy, OPUCN has direct, and perhaps somewhat unique, historical experience with the impacts of load growth forecasts which fail to materialize. As noted at Exhibit 3, page 31 of its Application, following each of its 2008 and 2012 rate cases, OPUCN's actual load fell materially short of its load forecasts, and negatively affected its financial performance.

282. Oshawa appears to be poised for a growth rebound over the next few years, but as repeatedly stated by OPUCN, this expectation is not without significant and material risk, which risk has nothing to do with prudent operation of a distribution utility.

ISSUE 5: REVENUE REQUIREMENT

Cost of Long-Term Unfunded Debt

283. Energy Probe has argued that in respect of forecasting the cost of unfunded long-term debt, OPUCN should not use the Board's deemed long-term debt rate, but rather should be required to provide evidence of the rate which it expects to pay on new loans.

284. Energy Probe asserts this position on the basis that in OPUCN's June 23 update (Exhibit K1.2), OPUCN indicated that it has entered into a long term loan agreement for $15 million for a term of 7 years at a rate of 2.71%, which is approximately 200 basis points below the Board's deemed rate.

285. Energy Probe submits that this is clear evidence that Oshawa has the ability to borrow at rates significantly below the deemed rate.

286. The long term loan agreement for $15 million at a rate of 2.71% is <u>not</u> evidence that OPUCN has the ability to borrow at rates significantly below the deemed rate.

287. The 2.71% rate secured by OPUCN was struck on June 17, 2015, while the 4.77% deemed long term rate currently prescribed by the Board was set in November 2014 – a gap of approximately 7 months. The difference in the two rates is driven by changes in market conditions, not the ability of OPUCN to borrow on more favourable terms.

288. For example, one of the inputs in the OEB deemed long-term rate calculation, the 'Canada 30-Year Bond Yield', has dropped approximately 20% since the 2015 deemed rate was set. Persistence of this trend through the end of 2015 would drive the OEB deemed rate for 2016 lower, all other inputs being equal.

289. OPUCN also has a 7 year loan agreement with TD Bank for $7 million at a rate of 3.57%, struck on December 21, 2012. The closest comparable deemed long term rate was set by the Board in November 2012, a gap of approximately 2

months. In this case the difference between the deemed long-term rate of 4.03% and the actual rate is less than 50 basis points.

290. Energy Probe also argues that is the Board approves a one mid-term model for OPUCN's Custom IR plan, then 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.

291. OPUCN notes that all parties (including Energy Probe) support annual adjustment (under a Custom Rate plan) of OPUCN's cost of capital, based on the Board's then current cost of capital parameters. OPUCN continues to believe that this is an appropriate approach, and does not believe there is merit in attempting to forecast the long term debt rate for use in place of the deemed rate.

292. OPUCN is not expecting to seek additional funding until 2017. High level calculations indicate any resulting change in Revenue Requirement (for example, using 2015 actual rate of 2.71% as the forecast) would be below the materiality threshold for this application.

293. Allowance for an annual adjustment for updated cost of capital parameters will ensure that any differences between actual and deemed rates are minimised.

ISSUE 6: DEFERRAL AND VARIANCE ACCOUNTS

294. OPUCN is not seeking to clear, but is proposing to continue, the Group 1 and Group 2 accounts listed in tables 9-2 and 9-3 of Exhibit 9, with the exception of the Special Purpose Charge Variance Account (1521).

295. Parties are generally in agreement with this approach, with the exception of Board Staff who favour disposition. Staff contends that the *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* (*EDDVAR Report*) indicates that unless otherwise justified by the distributor all account balances should be disposed of at rebasing.

296. OPUCN submits that, particularly for the Group 1 amounts, disposition is not appropriate. The totals available for disposition at the end of 2013 and 2014 were receivables (owing to OPUCN) of $2.2m and $4.2m respectively. However the average balances of these accounts were payables (owing to customers) of $1.1m and $0.2m respectively. In addition, the $4.2m receivable at Dec 2014 had swung to a payable of $1.1m at March 2015.

297. OPUCN intends to seek disposition of the Group 1 account balances annually as necessary over the 2015 to 2019 period and would do so in compliance with the *EDDVAR Report*. This will ensure that balances do not grow too large over the plan term.

298. OPUCN is seeking approval to maintain, but is not seeking to clear, the Tax Rate Changes Deferral Account and the Pension Cost Differential Deferral Account.

299. Parties are generally in agreement with this approach, with the exception of Energy Probe. Energy Probe argues that the Tax Rate Changes Deferral Account should be closed on the basis that OPUCN should be subject to any risk of tax related changes, as is any business.

300. OPUCN submits that there is no way for OPUCN to mitigate or plan for this risk, as rate design does not allow for alternative assumptions on tax rates to be used.

As such, no change in the Board's policy in this respect is justified, and the deferral account for any impacts resulting from tax changes is appropriate.

301. OPUCN is requesting approval of several new deferral/variance accounts, all as detailed at Exhibit 1, Tab C.

302. The need for these accounts depends on the Board's determination of OPUCN's Custom IR proposal, the merits of which are addressed in OPUCN's Argument in Chief and, as appropriate, elsewhere in this Reply Argument.

ISSUE 7: COST ALLOCATION AND RATE DESIGN

303. Parties are generally in agreement with the proposed methodology for determining cost allocation and rate design.

304. Some parties have argued that, if annual adjustments are approved for customer connections and load, then the cost allocation and related rate design models should also be updated annually. OPUCN`s reasoning for not proposing this initially was to minimise the complexity of the annual adjustment process, but OPUCN accepts the value of updating these when rates are adjusted. OPUCN has noted elsewhere in this Reply Argument that a one mid-term review model would entail one cost allocation run during OPUCN's Custom IR Plan term.

305. Most parties argue against the rate smoothing proposal submitted by OPUCN, with arguments ranging from it being unnecessary to not being worth the interest expense that would accrue because of it.

306. OPUCN agrees that rate smoothing is not technically necessary given the Board directs that distributors must file a mitigation plan only if total bill increases for any customer class exceed 10%, and OPUCN has no such classes. However, bill impacts in 2015 as calculated in (updated) Appendix 2-W for the "Sub-Total B – Distribution" line do exceed 10% for certain rate classes, followed by more modest increase in years 2016 to 2019.

307. OPUCN is proposing rate riders that will spread these increases evenly over the 2015 to 2019 rate period. OPUCN believes that this approach serves the need for reasonably stable and affordable rates for customers.

308. OPUCN continues to endorse a rate smoothing approach as it has proposed, for the reasons set out in its Argument in Chief (paragraphs 48-50).

ISSUE 8: IMPLEMENTATION

Implementation Date

309. All parties have argued that the effective date for rates arising from the Board's decision in this application should be the first of the month following the month in which the decision is issued.

310. OPUCN has considered the various previous Board decisions cited by the parties in support of this argument, and concedes that the Board has articulated a general practice to the effect that where late or incomplete filing by the applicant is the reason that the decision is issued following the date on which the applicant has requested rates be effective, the Board will not order rates to be effective on a date earlier than the date of the decision save in compelling circumstances.

311. OPUCN also concedes that there are no reasons external to OPUCN's control which resulted in the timing for filing of its Custom IR application.

312. OPUCN does, however, submit that there are good reasons in the circumstances of this application for the Board to set rates effective on a date prior to the date of its final order. These reasons are:

    a. OPUCN's evidence is that it has made diligent efforts to comply, in all respects, with the principles and policies of the *RRFE* and the Board Filing Guidelines in respect of Custom IR rate applications, and the resulting application has been both well thought out and comprehensively presented. Unlike some of the applications cited by the parties in support of arguments for an effective date following the date of the decision, OPUCN's application was not incomplete at the time of filing. Quite the opposite.

    b. In particular, OPUCN's Distribution System Plan is extremely comprehensive, and has been subject to full external validation by a number of 3rd party work and reports filed in support of this application.

    c. OPUCN's application is one of the first, if not the first, comprehensive supported Custom IR application, including both a comprehensive and externally validated distribution system plan, and comprehensive external benchmarking. Despite differences of opinion regarding the implications of the benchmarking obtained, there can be no dispute that OPUCN has filed a significant amount of comprehensive benchmarking evidence in support of its application.

d. OPUCN took time to evaluate its application in light of recent decisions regarding Custom IR applications, including both the Horizon settlement/decision and the recently released Hydro One decision, to ensure that its application continued to meet the Board's expectations for Custom IR plans.

e. There is uncontested evidence that if new rates are not made effective prior to the date of the decision, OPUCN would suffer a very material earnings shortfall in 2015. Based on OPUCN's evidenced 2015 costs, if rates were not effective until September 1, 2015, it would suffer a revenue shortfall of $1.8 million, and be in an "off ramp" situation with a projected earnings shortfall of 345 basis points.[52]

313. Most of the arguments[53] suggest that financial harm to the applicant resulting from late implementation of rates has been determined in the Board's recent decision in the Ontario Power Generation (OPG) payments case [EB-2013-0321] not to be a cogent reason for setting rates to recover incremental revenues from periods prior to the date of the rate order. This is not a proper read of the OPG decision.

314. In the OPG decision, the Board found that, contrary to OPG's argument, it was not legally compelled to set rates effective the date that rates have previously been declared interim.[54] OPUCN does not dispute this proposition.

315. In the foregoing context, the Board stated that "just and reasonable rates" can fall within a range, and that there is no defined line past which rates immediately become unreasonable. While valid, this reasoning does not support a rate order that results in an expected revenue shortfall from a fair return standard of 345 basis points.

316. OPUCN submits that Board Staff has implicitly recognized that such a reasonableness standard must be applied by the Board in acknowledging in its

[52] Exhibit J3.4.
[53] CCC Argument, page 19, bottom; Energy Probe Argument, page 57, 3rd full paragraph; SEC Argument, paragraph 7.1.8; VECC Argument paragraph 12.8.
[54] EB-2013-0321, *Decision with Reasons*, November 20, 2014, page 133, first full paragraph.

comments on effective date that the Board should consider the financial effect on OPUCN of the date selected.[55]

317. In the OPG payments case the Board expressed concern that *"OPG's proposal [for effective date] would result in the entire two-year increase for the previously regulated assets being recovered over a significantly shorter time period, resulting in a [sic] higher monthly bill impact increases exceeding the $5.36 and $5.94 identified in the two published Notices of Application*".[56]

318. Cognizant of the concern for impact on ratepayers of recovery of additional revenue on account of rates having been interim, OPUCN has proposed to smooth recovery of additional revenues for the interim period over the balance of its Custom IR rate plan term, in tandem with its proposal to smooth rate increases for 2015 and 2016. Exhibit J3.4, page 4 (bottom table) shows that the overall impact on rates of this proposal is a compound annual increment of 0.3% over the period (2014-19).

319. OPUCN submits that this proposal addresses concerns for ratepayer impact, while minimizing potential intergenerational inequity. It also responds to the concern that effective rates seen by customers not be markedly higher than proposed rates as reflected in the Notice of Application.

320. In a number of the OEB decisions cited by parties (including the decision in the OPG Payments case), the applicant was responsible not only for late filing of its application, but for subsequent delays in the processing of the application:

a. In the OPG Payments case (EB-2013-0321, see page 136, bottom), OPG filed a major update to its application the day after filing the application, which necessitated issuing a new notice. New information then continued to be filed, which delayed the oral hearing by several weeks. The Board also found (see page 138) that OPG has various options for proceeding with its application. None of this is comparable to OPUCN's situation.

[55] Board Staff Argument, page 46.
[56] EB-2013-0321, *Decision with Reasons*, November 20, 2014, page 135, 2nd full paragraph.

b. In the Sioux Lookout Hydro Inc. case (EB-2012-0165, see page 3, 2nd full paragraph), the Board found that the preparation of a conventional cost of service application should be part of the ongoing business process of the utility. VECC has quoted this finding in its Argument (paragraph 12.4). While fully admitting to its regulatory responsibilities, OPUCN respectfully notes that filing one of the first, if not the first, comprehensive and fully benchmarked Custom IR applications is not quite comparable to the filing of a "conventional cost of service application".

c. In the Hydro Hawkesbury Inc. case (EB-2013-0139, see page 3) the Board noted that the initial application was incomplete, and a completed application was not effected until 2 months later. OPUCN's evidence is that it took the time, up front, to ensure a complete and comprehensive application. Its success in this respect has been acknowledged by the parties.

d. In the Centre Wellington Hydro Case (EB-2012-0113, see page 2, bottom), the company revised its evidence which added a second round of interrogatories and delayed the filing of submissions.

321. OPUCN fully appreciates its regulatory obligations to file complete and timely applications, and properly manage its regulatory responsibilities. Indeed, to the extent that it has valid reason for filing late, it was precisely in the interests of properly addressing those regulatory obligations that OPUCN's filing was late.

322. Thus while the timing of its current application admittedly fell short of these standards, it is respectfully submitted that the degree of thought, comprehensiveness, and response to the Board's filing and evidentiary expectations mitigates, in the current circumstances, this isolated shortfall.

SEC's Proposition for Repayment to Customers - 2012/13 Efficiency Cohort Placement

323. In the course of working with PEG on benchmarking in support of the application, OPUCN discovered that in the years 2002 through 2005 it has erroneously recorded, and filed with the OEB, its kilometers of line. In these years OPUCN

recorded, and reported, more kilometers of line that it has since discovered it had in that time frame.[57]

324. The historical result of this error was that OPUCN's predicted costs were higher than they would otherwise have been, and thus its observed efficiency (having lower costs than predicted) was also higher than it would otherwise have been, leading to OPUCN having been placed in higher efficiency cohort, and having a lower stretch factor, in each of 2012 and 2013 than it otherwise would have had.

325. This error has been corrected for the purposes of PEGs benchmarking work filed in support of OPUCN's current application. The only potential impact that this error, since corrected, would have on this application is that it understates the incremental efficiencies relative to previous periods to be committed to by OPUCN through its current plan period rate proposal.[58]

326. SEC, however, argues that the Board should, in its decision on this application, order OPUCN to refund money to customers on account of rates being higher than they should have been in 2012 and 2013.

327. SEC provides no information on the impact or materiality of this proposition. There is none on the record.

328. Though it can't point to evidence on the record, as it was not asked about this and there is no evidence on the point, in light of SEC's unsupported proposition OPUCN advises that it has calculated that the impact for the two years in question, if it in fact was in the wrong efficiency cohort as a result, would have been, in aggregate, approximately $70,000.

329. OPUCN also notes that it has since refilled, with better GIS data, its kilometers of line by correcting its RR filings back to 2008 (as the Board permitted it to do), and the errors have been found, with this better data, to have been not as large as

[57] Exhibit 10.0-Staff-58
[58] Technical Conference Transcript 1, page 60, lines 8 through 18.

earlier reported to PEG. The originally filed data, the interim data supplied to PEG, and the more recently updated data as filed with the OEB, is set out below:

Year Ending	RRR OEB as filed	Km of Line used by PEG	As Revised Final KM of line
2005	924	823	858
2006	934	833	868
2007	953	852	887
2008	948	852	887
2009	950	852	887
2010	955	854	889
2011	987	886	921
2012	996	895	928
2013	1007	906	941
2014	950	950	950

330. Based on the earlier data OPUCN disclosed, as cited by SEC in its Argument, that PEG had confirmed that the cohort placement for OPUCN would have changed, using corrected data, in 2012 and 2013. That is no longer clear, as the data discrepancy has been found to be less than previously thought.

331. SEC relies on the recently issued Essex Powerlines *Partial Decision and Procedural Order No. 3* (dated March 25, 2015, EB-2014-0301/0072) in support of its proposal that OPUCN be directed to return this $70,000 to ratepayers.

332. The finding relied on by SEC expressly states that the Board could impose financial or other consequences on a utility, including repayment to customers, *"in situations where errors are the result of a utility's negligence"*.

333. In the Essex Powerlines case, the Board expressed concern regarding the *"numerous examples"* of Essex Powerlines not adhering to the Board's Regulatory Accounting Handbook and Uniform System of Accounts. In light of these numerous examples, the Board stated that it *"is very concerned about the regulatory accounting controls in place"*.[59]

[59] See bottom of page 12 and top of page 13 in the referenced *Partial Decision and Procedural Order No. 3*.

334. Board Staff characterized the circumstances in that case as *"systematic carelessness towards ensuring proper regulatory accounting"*.[60]

335. The Hearing Panel went on, however, to conclude, *"based on the evidentiary record"*, that *"Essex Powerlines demonstrated carelessness towards ensuring proper regulatory accounting procedures and controls"*.

336. The remedy adopted by the Board was to order an audit, to direct that the cost of the audit be absorbed the shareholder, and to disallow an increase in base rates on the basis that, with the errors made, Essex Powerlines has neither demonstrated the desired *RRFE* outcomes nor demonstrated value to customers.

337. While SEC quotes the Essex Powerlines decision in support of its proposition, it neglects to emphasize the critical "negligence" threshold identified by the Board in that case. SEC effectively ignores this threshold, in that it does not even argue, let alone cite any facts, to support a finding that OPUCN has been negligent. Perhaps that is because there are no such facts. Indeed, the matter was not even explored during the proceeding.

338. For this reason alone, the Board should disregard SEC's argument on this point.

339. In any event:

a. the amounts in issue are not material;

b. the errors in issue were more than 10 years old, and predated all of the current senior management of the utility; and

c. even with these alleged "over collections" (though it is not even clear, give updated data, this was the case), OPUCN in fact under earned significantly in both 2012 and 2013, and with lower rates, it simply would have under earned more.

340. OPUCN has been forth right in its disclosure of this historical error and has corrected it. It does not impact this application. It did not materially impact

[60] See top of page 11 in the referenced *Partial Decision and Procedural Order No. 3*.

ratepayers. It is neither negligent nor systematic. SEC's proposition should be summarily rejected.

CONCLUSION

341. As noted above, the Hydro One decision was issued after OPUCN filed its application. Until that decision, the only other guidance provided by an OEB Hearing Panel was Enbridge's 2012 application for 2014-18 rates [EB-2012-0459]. In the Enbridge decision, the Board accepted an application based on 5 years cost of service forecasts, precisely like OPUCN's.

342. In the Enbridge decision the Board also accepted revenue cap plan which requires in plan period load forecast and associated billing determinant updates, precisely like OPUCN has proposed.

343. Again, this model was the only model considered by an OEB Hearing Panel at the time that OPUCN developed and filed its Custom IR application.

344. OPUCN respectfully submits that the Board should consider this context in evaluating the arguments filed by all parties. As was also noted (with appreciation) at the outset of this argument, many of the parties have acknowledged OPUCN's efforts to bring forward a reasoned, supported, and *RRFE* compliant Custom IR proposal.

345. At page 58, first full paragraph of its Argument, in arguing that despite the 345 basis point earnings shortfall that would result from a September 1st effective date for OPUCN's 2015 rates , Energy Probe makes the following statement:

> *Under the RRFE, Energy Probe submits that the focus is on the customer, or the ratepayer.*

Irrespective of the financial consequences to the utility.

346. OPUCN is pleased that at least Board Staff acknowledged that the financial consequences to OPUCN of a later rate implementation date should be

considered by the Board in determining this issue. Those consequences are a forecast $1.8 million (345 basis point) earnings shortfall in 2015.[61]

347. The singular lens reflected in Energy Probe's statement seems to be shared by all of the other intervenors in their approach to this application. Every issue is seen exclusively from the perspective of the ratepayer, and this view is nowhere tempered by consideration of the position of the shareholder.

348. While acknowledging that the *RRFE*, and the Board's recent policy emphasis in general, has had a strong focus on customers, it is not reasonable to argue, or assume, that this is the singular focus which should determine the Board's decisions.

349. Costs and revenues must be fair and reasonable, not simply lower.

350. Efficiencies directed must be reasonably capable of being realized. Even in properly competitive markets, production costs (including a reasonable cost of capital) are a floor for prices.

351. At some point, superior efficiency must be recognized and a determination made that, based on supporting evidence, a utility is superior in its efficiency and only so much blood is available from this stone.

352. OPUCN submits that it has provided comprehensive benchmarking – its own statistical benchmarking and third party econometric and capital cost forecast benchmarking - which provides strong evidence of current and continuing superior efficiencies, and ongoing productivity improvements.

353. OPUCN has also responded directly to the Board's invitation for innovative incentive mechanisms designed to *"incent behaviour similar to that seen in commercially-oriented, consumer market-driven companies"*, to quote once again from the recent Hydro One decision (page 14).

[61] Exhibit J3.4.

354. To quote PEG;

> *The Board can thus be satisfied that OPUCN's "utility performance" under the Custom IR rates proposed will continue to reflect strong cost efficiencies and quantifiable value to OPUCN's customers.*

355. OPUCN submits that these evidenced conclusions allow for the "outcomes based" approach to regulation contemplated by the *RRFE*.

ALL OF WHICH IS RESPECTFULLY SUBMITTED by:

"Original Signed By"

GOWLING LAFLEUR HENDERSON LLP, per:
Ian A. Mondrow
Counsel to Oshawa PUC Networks Inc.

Appendix A

	Indexes	OM&A Subject to (PEG) Index	OM&A Excluded from (PEG) Index	Total
2012 OM&A		10,665	402	11,067
2013 scale index	1.00%	107	4	111
2013 IPI	2.20%	235	9	243
2013 productivity	-0.72%	(77)	(3)	(80)
2013 stretch	-0.40%	(43)	(2)	(44)
2013 OM&A		10,887	410	11,297
2014 scale index	1.56%	170	6	176
2014 IPI	1.70%	185	7	192
2014 productivity	-0.31%	(34)	(1)	(35)
2014 stretch	-0.30%	(33)	(1)	(34)
2014 OM&A		11,175	421	11,597
2015 scale index	1.60%	179	7	186
2015 IPI	1.60%	179	7	186
2015 productivity	-0.31%	(35)	(1)	(36)
2015 stretch	-0.30%	(34)	(1)	(35)
2015 OM&A		11,465	432	11,897
Proposed				12,054
Over/(Under)				157

Appendix B

OM&A Indexed with 3% Growth in Customer Connections

	Indexes	OM&A Subject to (PEG) Index	OM&A Excluded from (PEG) Index	Total
2015 OM&A proposed		11,622	432	12,054
2016 scale index	2.77%	322	12	334
2016 IPI	1.73%	201	7	209
2016 productivity	-0.31%	(36)	(1)	(37)
2016 stretch	-0.30%	(35)	(1)	(36)
2016 OM&A		12,074	449	12,523
Proposed				12,533
Over/(Under)				10
2017 scale index	2.98%	360	13	373
2017 IPI	1.93%	233	9	242
2017 productivity	-0.31%	(37)	(1)	(39)
2017 stretch	-0.30%	(36)	(1)	(38)
2017 OM&A		12,593	468	13,061
Proposed				12,824
Over/(Under)				(237)
2018 scale index	2.92%	368	14	381
2018 IPI	2.45%	309	11	320
2018 productivity	-0.31%	(39)	(1)	(40)
2018 stretch	-0.30%	(38)	(1)	(39)
2018 OM&A		13,193	491	13,683
Proposed				13,033
Over/(Under)				(650)
2019 scale index	2.98%	393	15	408
2019 IPI	2.55%	336	13	349
2019 productivity	-0.31%	(41)	(2)	(42)
2019 stretch	-0.30%	(40)	(1)	(41)
2019 OM&A		13,842	515	14,356
Proposed				13,102
Over/(Under)				(1,254)
Cumulative Efficiencies				(2,132)

OM&A Indexed with 1.5% Growth in Customer Connections

	Indexes	OM&A Subject to (PEG) Index	OM&A Excluded from (PEG) Index	Total
2015 OM&A proposed		11,622	432	12,054
2016 scale index	1.62%	188	7	195
2016 IPI	1.73%	201	7	209
2016 productivity	-0.31%	(36)	(1)	(37)
2016 stretch	-0.30%	(35)	(1)	(36)
2016 OM&A		11,940	444	12,384
Proposed				12,533
Over/(Under)				149
2017 scale index	1.83%	219	8	227
2017 IPI	1.93%	230	9	239
2017 productivity	-0.31%	(37)	(1)	(38)
2017 stretch	-0.30%	(36)	(1)	(37)
2017 OM&A		12,316	458	12,774
Proposed				12,824
Over/(Under)				50
2018 scale index	1.76%	217	8	225
2018 IPI	2.45%	302	11	313
2018 productivity	-0.31%	(38)	(1)	(40)
2018 stretch	-0.30%	(37)	(1)	(38)
2018 OM&A		12,760	474	13,234
Proposed				13,033
Over/(Under)				(201)
2019 scale index	1.82%	232	9	241
2019 IPI	2.55%	325	12	337
2019 productivity	-0.31%	(40)	(1)	(41)
2019 stretch	-0.30%	(38)	(1)	(40)
2019 OM&A		13,240	492	13,732
Proposed				13,102
Over/(Under)				(630)
Cumulative Efficiencies				(633)