EB-2013-0116

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

AND IN THE MATTER OF an Application by Cambridge and North Dumfries Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014.

REPLY SUBMISSIONS OF CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

May 26, 2014

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REPLY SUBMISSIONS OF CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

DELIVERED: MAY 26, 2014

A. INTRODUCTION

1. Cambridge and North Dumfries Hydro Inc. ("**CND**" or the "**Applicant**") filed a cost of service application (the "**Application**") with the Ontario Energy Board (the "**Board**") under section 78 of the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that CND charges for electricity distribution, to be effective May 1, 2014. The Board assigned the Application file number EB-2013-0116.

2. On April 30, 2014, CND presented its argument-in-chief orally to the Board panel (referred to herein as the "**AIC**"). CND is pleased to present this written reply to the Board staff ("**Staff**") submissions received May 8, 2014, the final argument of the Vulnerable Energy Consumers Coalition ("**VECC**") received on May 12, 2014, the final argument of the Energy Probe Research Foundation ("**EP**") received on May 12, 2014, and the final argument of the School Energy Coalition ("**SEC**") received on May 13, 2014 (Staff, VECC, EP and SEC shall be referred to collectively as the "**Parties**").

3. These reply submissions are organized to address the general context under the RRFE, followed by a specific reply in respect of each of the five areas of dispute:

   A. Introduction
   B. Context: The RRFE
   C. OM&A
   D. Cost of Capital – The Long Term Debt Rate
   E. Other Income – Interest Income
   F. GS > 50 Rate
   G. Removal Costs
   H. Conclusion

B. CONTEXT: THE RRFE

4. In its AIC,[1] the Applicant indicated that it is among the first LDCs to apply under the Board's *Renewed Regulatory Framework for Electricity Distributors* as described in the Report of the Board dated October 18, 2012 (the "**RRFE**") and is the first LDC to proceed to an oral hearing under the RRFE (albeit with a limited number of areas remaining in dispute).

5. It is worth noting at the outset that the Parties were unable to reach a complete settlement on any of issues 1-6 of the Board's approved issues list – the issues that deal with foundation, performance measures, customer focus, operational effectiveness, public policy responsiveness and financial performance.

6. In this context, the Parties have suggested various different and creative approaches to how the Board should interpret and apply its RRFE framework. The Applicant believes that clarity in respect of overall approach under the RRFE would be helpful in the circumstances. In this regard, the Applicant provides its general policy submissions in respect of each of the key RRFE issues below – starting with operational effectiveness and customer focus.

B.1 Operational Effectiveness (Issues 4.1, 4.2, 4.3 and 6.2)

7. Ensuring that the Applicant is incented to achieve continuous improvement in productivity and cost performance on a long-term and sustainable basis is a core RRFE outcome. Issue 6.2 of the Board's approved issues list captures this concept by requiring a demonstration that the savings resulting from operational effectiveness initiatives are sustainable.

8. The key word is sustainable. Sustainable efficiencies are those that can be continued without jeopardizing the ongoing safety, reliability, or quality of utility activities and services. In addition, sustainable efficiencies are generally expected to endure beyond the rebasing year such that ratepayers will benefit from all of those efficiencies, if not immediately, then certainly by the next rebasing year and in perpetuity.

[1] Transcript dated April 30, 2014 at pg. 3 at line 23 to pg. 6 at line 10.

9. However, there is a critical distinction that needs to be made between sustainable efficiencies, on the one hand, and short-term cost cutting, on the other.

10. Unlike sustainable efficiencies, short term cost cuts cannot necessarily be continued beyond the short term without jeopardizing the safety, reliability and quality of utility activities and services. Unlike sustainable efficiencies, short term cost cuts will not necessarily endure after rebasing.

11. Each of the Parties have argued that some level of arbitrary reduction in OM&A should be imposed in the test year, although none of the Parties have identified how those short-term cost cuts will lead to long-term or sustainable efficiencies. That is because they won't.

12. The Applicant detailed the evidence on the record about its numerous long-term and sustainably focused operational effectiveness and efficiency initiatives in its AIC.[2] It is not our intent to repeat that now.

Historic Performance Over the 3GIRM Term

13. It is worth noting at the outset that none of the Parties mention that between 2010 and 2013 the Applicant was the subject of the Board's 3rd Generation Incentive Regulation Mechanism methodology, which imposed an I minus X approach to rate setting (i.e. annual adjustments according to a Board-approved formula that includes components for inflation (I) and the Board's expectations of efficiency and productivity gains (X)). This approach included a direct financial incentive (a stretch factor and a productivity factor) for the Applicant to achieve sustainable long-term efficiencies. The Applicant did not have a choice of whether or not to achieve these efficiencies – it was built into the rate setting model. These efficiencies were achieved through operational effectiveness initiatives that were undertaken in the past (and were thus not the subject of questions in the discovery process), and are embedded directly in the Applicant's forecasted costs of providing service in the test year for this Application. The efficiencies have allowed the Applicant to do more with less, and ratepayers are already benefiting from this.

[2] Transcript Volume 2 dated April 30, 2014 at pg. 10 at line 22 to pg. 15 at line 6.

14. The real challenge is that the key industry wide cost drivers – including new government obligations, such as the introduction of smart meters and time-of-use pricing, new regulatory requirements arising out of the Green Energy and Green Economy Act, the LEAP program, the call-before-you dig program, regulatory and IFRS-driven accounting changes, rising wage and benefit costs, and the hiring of certain positions related to succession planning - have all required more from CND than these efficiencies have been capable of addressing on their own.

15. In this context, Staff's suggestion that the Enersource (EB-2012-0033) and Burlington Hydro (EB-2009-0259) decisions can be used to justify an arbitrary or formulaic short-term reduction in OM&A costs are very concerning. EP cites these same two decisions as well a variety of other hand-picked Decisions designed to advance EP's position that the Board should focus on short-term cost cutting for OM&A.

16. The Applicant submits that none of these decisions are analogous to the present circumstances for two key reasons. First, none of these decisions were made in respect of the same time period in question (2010-2014) and therefore the underlying industry wide cost drivers are fundamentally and factually different that those identified in this Application. In addition, none of these decisions were made under the Board's RRFE which is an outcome oriented form of regulation focused on sustainable long-term operational efficiencies not short-term cost cutting.

17. CND is not the only LDC faced with challenges posed similar industry-wide cost drivers over the 2010-2014 period - they are impacting all LDCs in varying degrees. CND has prepared a summary in Table 1 below to demonstrate that CND's annual OM&A cost increases between 2010 and 2014 are consistent during the entire 3GIRM term (and not loaded into the test year), and are comparable with the Board approved 2010-2014 total OM&A cost increases for at least two other LDCs. To assist the Board, CND has included detailed footnotes in the Table to identify the source of the OM&A data for each LDC.

18. The first comparison is taken from the Board's Decision and Order dated March 20, 2014 in respect of an application by Kitchener-Wilmot Hydro Inc. ("**KW**") in EB-2013-0147 for a change in distribution rates to be effective January 1, 2014. KW went to hearing on

a number of issues, including OM&A, and Table 1 below provides a summary of the evidence on historic OM&A costs together with the Board approved OM&A costs for the 2014 test year. While the KW decision is not an RRFE decision – it is in respect of the same historic period as CND's application, and therefore both KW and CND are responding to similar industry-wide cost drivers. While the KW Decision is the subject of a motion to review by SEC (EB-2014-0155), the motion is limited in scope to the Board's determination on a different area of dispute in that proceeding (working capital allowance). The Board's decision on OM&A is not affected by the SEC motion.

19. The second comparison is taken from the Board's Decision and Order dated May 1, 2014 in respect of an application by Oakville Hydro Electricity Distribution Inc. ("**Oakville**") in EB-2013-0159 for a change in distribution rates to be effective May 1, 2014. The Oakville Decision was made in the context of the RRFE, where the Board found that "the Settlement Proposal, when examined in its entirety, is consistent with the RRFE's four performance-based outcomes: customer focus, operational effectiveness, public policy responsiveness, and financial performance. The Board's finding in this regard is based on its interpretation of the RRFE in the context of this transitional year of its implementation." It is worth acknowledging that, as noted in this quote, the Decision is based on the Board's acceptance of a settlement by the Parties in respect of OM&A, and that because of the complex and interconnected nature of settlements in general, the terms of a settled issue may not necessarily be accepted by the Board in other proceedings. However, the Oakville Decision is still helpful because – much like the KW Decision –it is in respect of the same historic period as CND's applicant and therefore similar industry-wide cost drivers also apply.

Table 1: OM&A Cost Comparison Among Select 2014 Rate Applications

		2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast
CND	OM&A[3]	$9,580,557	$10,762,423	$12,017,643	$13,807,478	$14,877,658
	Annual Change (%)		12.34%	11.66%	14.89%	7.75%
	Total Change (2014 to 2010)					55.29%
KW	OM&A[4]	$12,270,957	$13,607,221	$16,827,196	$17,431,075	$18,379,260
	Year-to-Year Change (%)		10.89%	23.66%	3.59%	5.44%
	Total Change (2014 to 2010)					49.78%
Oakville	OM&A[5]	$11,017,743	$13,133,111	$14,006,880	$18,118,740	$17,600,000
	Year-to-Year Change (%)		19.20%	6.65%	29.36%	-2.86%
	Total Change (2014 to 2010)					59.74%

20. Referring to Table 1, there is no evidence on the record to support SEC's suggestion that the Applicant is using the test year to "load up productivity spending."[6] The Parties agreed on capital in the Settlement Proposal, and the evidence is that CND's OM&A spending has been increasing consistently – year-over-year – since 2010. In fact, the proposed OM&A increase in the test year over 2013 actuals (7.75%) is less than the average increase over the prior three years (12.96%). Put simply, CND has and will continue to diligently pace its responses to all cost drivers throughout the IRM term.

Future Performance Over the 4GIRM Term

21. The Board has adopted a similar I minus X approach to rate setting under its 4th Generation Incentive Regulation Mechanism under the RRFE. As was noted in AIC, with an average historic costs that is seven percent (7%) less than PEG's model's prediction, CND was ranked 28th by PEG in their econometric benchmarking of 73 LDCs and was assigned to Group 3 by the Board which will result in a stretch factor that will apply for the balance of the IRM term.

[3] See the CND response to Undertaking J1.5.
[4] From KW's response to Undertaking No J1.7 in EB-2013-0147 and page 16 of the Board's Decision and Order dated March 20, 2014.
[5] From Oakville's Application in EB-2013-0159 (Appendix 2-JB Recoverable OM&A Cost Driver Table Ex 4, Tab 2, Schedule 3 Page 3) and the Board approved Settlement Proposal at page 26 of the Decision and Order dated May 1, 2014.
[6] SEC Final Argument at para. 2.3.6.

22. In this context, SEC argues that "the purpose of IRM is to incent utilities to invest in productivity, knowing that they will benefit from that investment during the IRM period. On rebasing, the benefits are shifted to the ratepayers, subject to any efficiency carryover mechanism employed by the regulator. In our view, IRM is not effective if the investments are made by the ratepayers as part of the rebasing budget, while the IRM period benefits accrue to the shareholder. This is not the concept, and it is not fair."[7]

23. The problem with this line of reasoning is that it ignores the fact that ratepayers do benefit, each year, directly and immediately, under the Board's 4GIRM model through the application of a stretch factor which flows the benefits of any operational effectiveness initiatives undertaken by the Applicant directly to the ratepayers.

24. SEC, Staff and EP each acknowledge that CND has identified numerous operational effectiveness initiatives in its Application, however they express concern because the benefits of those savings are not included in revenue requirement in the test year. There are two reasons for this, first it would be premature to include the benefits because the benefits will not accrue in the test-year (this is entirely appropriate in a forward test-year cost of service Application). Second, the benefits in future years are very hard to estimate.

25. This second point bears emphasis. Under cost of service regulation, a utility is required to forecast what it will cost to serve in the future, which itself is not a trivial task and is the subject of much discourse on the evidentiary record. But to forecast potential benefits of productivity initiatives, a utility would have to forecast what it *might* cost to serve in the future *assuming a particular productivity initiative was not undertaken*. This becomes even more difficult to do if various productivity initiatives are interrelated or dependent. And one can only imagine the type of interrogatories that will arise once this degree of speculation is introduced into the evidentiary record.

26. What the Parties fail to acknowledge is that under the I minus X model, the Applicant bears the risk throughout the 4GIRM term if it is unable to deliver on the sustainable operational efficiencies at least equal to the Board's assigned stretch factor. Ratepayers

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[7] SEC Final Argument at para. 2.3.3 and 2.3.4.

benefit during the IRM period, regardless of whether the underlying operational efficiencies materialize or not. Only if the Applicant is able to achieve sustainable operational efficiencies in excess of the stretch factor (i.e. management outperforms expectations) will the benefits accrue to the shareholder. And these benefits will be short-lived, only for the remainder of the applicable IRM term. After the next rebasing, ratepayers gain the full benefit of all operational efficiencies accrued during the prior IRM term and the Applicant will need to start again in its efforts to achieve sustainable operational efficiencies during the next IRM period.

27. In this regard, the Applicant is very concerned that some of the Parties would like to have their cake (to justify an arbitrary reduction of OM&A in the test year) and eat it too (benefit again from stretch factor productivity initiatives, the costs of which have already been clawed back during the cost of service application).

28. Simply put, the obligation to undertake sustainable operational effectiveness initiatives is part of the Board's expectations of LDC management under the RRFE. The costs associated with undertaking these operational effectiveness initiatives during the test year are prudent and legitimately included as a cost of service during rebasing (and those costs in respect of operational effectiveness initiatives that are incurred outside of the test year are not included).

29. During the remainder of the IRM term, the risk associated with any failure to ensure the operational effectiveness initiatives achieve the required benefits are imposed on the LDC. Only if an LDC's management can exceed expectations will any benefits accrue to shareholders. In this way, the Board's 4GIRM incents efficient management that is focused on continuous improvement through the implementation of sustainable operational efficiencies that will at a minimum preserve, and ideally improve, shareholder returns over the short-term but will ultimately flow to the benefit of ratepayers over the long term.

B.2 Customer Focus (Issues 1.2 and 3.1)

30. Under issue 1.2 of the approved issues list, the Applicant must demonstrate that its customer engagement activities are commensurate with the approvals requested in the Application. Under issue 3.1, the Applicant must demonstrate that its proposed capital and operating expenses are appropriately reflective of customer feedback and preferences. In its AIC,[8] CND detailed its customer engagement activities which were specifically intended to meet these evidentiary requirements. CND will not repeat the evidence again now.

31. In respect of these issues EP argues that "Full engagement includes knowing the cost consequences so that informed choices can be made and informed views can be made known. Most importantly, customers were not engaged about their number one issue-better prices/lower rates."[9]

32. CND strongly disagrees with EP's suggestion that CND's customer engagement activities were deficient in this regard. CND unambiguously acknowledges the importance of this issue at Exhibit 1, Tab 5, Schedule 2, Page 5, starting at line 6:

> "The number one priority identified by customers in every independent customer survey undertaken, is the need to provide better or lower prices. CND can respond to that customer need, in part through improved education about the various cost components on a bill, by communicating relevant Conservation and Demand Management programs that meet the needs of residential and commercial customers to ensure maximum uptake, resulting in saving energy and reduced hydro bills, and by continuing to ensure the overarching corporate Strategic Plan and budgeting process aligns with outcomes-based performance."

33. The residential customer survey, the results of which are found at Exhibit 1, Appendix 1-1A indicates that in 2012 while 45% of residential customers identified better prices/lower rates as among the most important things the utility can do to improve service (pg. 19 of 20), CND was given a grade of "A" which is above the provincial average grade of "B+" in terms of price and value of service (pg. 3 of 20) and 74% of respondents indicated CND provides good value for money, an increase over 72% in 2011 and higher than both the provincial average of 65% and the national average of 70%

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[8] Transcript dated April 30, 2014 at pg. 8 at line 25 to pg. 10 at line 20.
[9] EP Argument at pg. 4.

(pg. 12 of 20). Similar, though not identical, results can be found in the July 2013 commercial, industrial and institutional customer survey at Exhibit 1, Appendix 1-1B where one "key driver of overall customer satisfaction is Provides good value for your money" (pg. 20 and 21 of 43) and 73% of respondents indicate that CND provides good value for money (pg. 17 of 43).

34. To suggest that CND's customer engagement activities are deficient in this regard is misleading. Those questions formed the basis of CND's customer engagement activities, and forms a key input into CND's strategic planning and budgeting process.

35. In this context, and as noted in its AIC, CND has undertaken a number of expenditures in relation to improving its organizational capacity to identify and to respond to customer preferences. Noting this, Staff itemized the significant costs including capital additions and cost of staff additions at pg. 2 of their submissions. While Staff acknowledge that CND has shown it is focusing on engaging its customers and improving service to them, Staff "questions the pacing of expenses".

36. In this regard, CND notes that the Parties (excluding Staff, although Staff did ultimately support the proposed settlement) reached a complete settlement in respect of the capital expenditures proposed in the Application, including in respect of the bill connect, outage management system, interactive voice response, and distribution management system. This settlement was accepted by the Board, which means that Staff's real concern must be with the two items identified as cost of staff additions – specifically the addition of a communications manager and system control operator. CND will address these concerns under the OM&A submissions below.

37. However, CND believes that Staff's comment in respect of the Communications Manager position is particularly concerning. In response to 1.2-Staff-3(b), CND stated that:

> "In February 2013, CND hired a new Communications Manager. The new Communications Manager was hired in recognition of the requirement to deliver enhanced customer engagement as contemplated in the RRFE Report and is 100% dedicated to facilitate and provide timely, reliable, and responsive communication to customers using existing and new channels of communication launched to satisfy customer stated preferences. These communication channels include the new website, and new social media channels. This position is also required to collaborate with all departments to improve the communication experience for

> customers with respect to all customer focused projects. (Exhibit 1, Tab 5, Schedule 1, Table 1-15 Customer Engagement Focus)."

38. The new Communications Manager is a sensible response to the importance that customer focus and enhanced customer engagement have as key outcomes under the RRFE. If an Applicant lacks the necessary skills, expertise or organizational capacity to address this new RRFE emphasis on customer focus – bringing on an additional resource with the necessary skills focused on this role makes good sense.

39. For the Applicant, the evidence is that the Communications Manager is integral in collecting customer feedback and collaborating with all of the departments within the Applicant to ensure an organizational focus on customer preferences is maintained. It demonstrates an organizational commitment to achieving the RRFE outcome of customer focus (which the use of a one-time consultant would not). It allows the organization to develop a more sophisticated understanding of customer needs and preferences – leading to continuous improvements as the Applicant becomes better informed and more responsive over time.

40. In this context it would be unfair to, on the one-hand, obligate the Applicant to demonstrate that it has met the requirements of issues 1.2 and 3.1 in the Board's approved issues list and, on the other hand, to deny the Applicant the resource that it has specifically identified as being integral to meeting those obligations.

B.3 Planning (Issue 1.1)

41. The Parties were unable to reach agreement that the planning undertaken by the Applicant and outlined in the Application supports the appropriate management of the Applicant's assets.

42. In describing why this issue was unsettled, Mr. Sheppard explained that "I am not sure I am speaking for all of the intervenors, but they will jump in and correct me if I am wrong, I'm sure. There's a difference between saying the planning process is good -- and I think we generally agreed that this utility has followed a good process for their planning. But that doesn't mean that the result is right. That means that they had all the appropriate

process steps. They approached it in the right way, things like that, but you can still get the wrong answer using the right process."[10]

43. To be honest, the Applicant is struggling with this interpretation. Either its planning is appropriate, or it is not. This is separate and distinct from the particular results of that planning process (whether it is the forecasted capital budget, OM&A budget or financing plan). If the Applicant's planning process is not appropriate – then the Parties should identify specific deficiencies in the processes that are detailed on the evidence.

44. EP has attempted to do this in it its submissions in respect of issue 1.1. Specifically, EP argues that "the Distribution System Plan filed in Appendix 2-8A does not include a forecast of OM&A expenses over the 2014-2018 period. Nor does it include a financing plan for the assets to be managed."

45. This is both factually incorrect and misleading. It is incorrect because CND did include a forecast of System O&M costs over the 2014-2018 period as required in the Chapter 5 filing requirements.[11] It is misleading because there is no obligation to include a financing plan in the Chapter 5 filing requirements. CND clearly detailed the evidence on its financing plan elsewhere in its Application, which evidence is summarized in AIC.

46. EP goes on to argue that "the planning undertaken by CNDHI and outlined in the evidence does not support the appropriate management of the applicant's assets. Energy Probe provides further submissions under Issue 7.5 dealing with the appropriate treatment of the long term debt costs if the planning had been done appropriately and in the best interest of both the shareholder and ratepayer."[12] CND will respond to these specific concerns in respect of the long term debt cost area of dispute below.

B.4 Performance Measures (Issue 2.1)

47. Even though the Board had not yet finalized its proposed form of balanced scorecard to assess LDC performance in respect of the RRFE outcomes, CND took steps to draw on the work the Board and Staff had done prior to the filing of the Application to prepare its

[10] Transcript Volume 1 dated April 29, 2014 at pg. 13 at line 14-24.
[11] Exhibit 2, Appendix 2-8A page 6 of 157 at Table 3.
[12] EP Argument at pg. 3.

own form of balanced scorecard in Exhibit 1, Tab 4, Schedule 1 at Table 1-1, as subsequently revised in response to 2.1-Staff-5 and 2.1-SEC-14.

48. CND did this on a best-efforts basis proactively, even though it was not in the Board's filing requirements and many other 2014 filers chose not to do so, because CND believed it would provide additional information and facilitate the Board's determination in the RRFE outcome focused environment. CND will continue to monitor the progress of the Board's development of its model scorecard, and CND will incorporate new developments into its scorecard as they arise.

(1) Board Approved Plans

49. EP argues that (1) the fact that the Applicant's failure to move all customers to monthly billing as was proposed in its 2010 COS application, and (2) the fact that the Applicant was unable to realize on presumed savings arising from the loss of the water and sewer billing services contract both amount to a failure to deliver on a "Board-approved plan".

50. CND acknowledges that it did not move all customers to monthly billing. The evidence in 4.2-EP-12(b) is that:

> "At the time of the 2010 Rate Application, CND was in the midst of developing a new Customer Information System, utilizing SAP software, in partnership with two other electric distribution companies. The design and build of the shared Customer Information System included custom programming for monthly billing and monthly collection processes, only. For that reason, CND included the move to monthly billing in its 2010 Rate Application. The shared Customer Information System solution utilizing SAP software did not proceed. As a result, when the project was abandoned in December 2009, CND did not proceed with monthly billing of all customers."

51. This explanation was also touched on by Ms. Hughes during cross-examination.[13] It is perhaps also worth noting that $42,500 is not a material amount (CND's materiality level is $125,000).

52. Similarly, notwithstanding CND's efforts to mitigate the effect of the loss of the water and sewer billing services contract,[14] the full value of OM&A cost savings assumed in the 2010 decision did not materialize (although a portion of savings did result from

[13] Transcript Volume 1 dated April 29, 2014 at pg. 91.
[14] 4.2-EP-12.

accelerated meter readings) because resources were instead utilized to respond to other incremental obligations and cost drivers.[15]

53. What is concerning to the Applicant is the very liberal interpretation EP is giving to the term "Board-approved plan."

54. If this is what the Board intended in creating its issues list - such an interpretation will mean that after just and reasonable rates are established by the Board, management will no longer be free to manage the utility and respond to changing circumstances as required (as the experience with the SAP CIS noted above illustrates), because intervenors will use any such changes to justify arbitrary reductions in OM&A in future years. Put simply – if the world does not unfold exactly according to forecast, it appears the utility will be penalized in the future.

55. In the Applicant's submissions, this is not the intended meaning of the term "Board-approved plan."

56. The Applicant would refer the Board panel to Section 70(2.1) of the *Ontario Energy Board Act, 1998* which creates, as a deemed condition of every LDC's licence, an obligation for each LDC to comply with all Board approved plans as they relate to the expansion or reinforcement of the licensee's distribution system to accommodate the connection of renewable energy generation facilities, and the development and implementation of the smart grid in relation to the licensee's distribution system.

57. Under the RRFE, the Board has adopted an integrated approach to distribution network planning where all categories of network investments will be planned together, including investments for the renewal and expansion of networks and, where applicable, investments for the connection of renewable generation facilities, investments for smart grid development and implementation, and investments identified in the course of regional infrastructure planning exercises.

58. Because of this, the Applicant understood "Board-approved plans" to mean for the test year any previously approved Distribution System Plans prepared in accordance with the Chapter 5 consolidated filing requirements. The first such plan was filed by the

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[15] 2.1-EP-4.

Applicant in Appendix 2-8A, no previous plan exists. This interpretation is supported by reference to Section 5.4.2 of the Chapter 5 filing requirements, where the Board expressly requires distributors to compare actual vs. plan amounts over the historic period. Table 2 of those filing requirements includes a specific footnote that says "Historical "previous plan" data is not required unless a plan has previously been filed."

59. LDCs need to know in advance that they are going to be held to a particular plan if they are to manage their utility accordingly. The Chapter 5 consolidated filing requirements make it abundantly clear this is the Board's intention on a going forward basis for approved Distribution System Plans. Thus, it is incumbent upon the Applicant to manage consistently with its Board-approved plan during the 4GIRM term or be prepared to justify any deviations in that plan.

60. By contrast, the Applicant had no prior notice that the Board was moving away from its standard practice of allowing management to take prudent steps to manage its utility once rates were set in 2010. EP is asking the Board to apply a new standard to assessing the Applicant's conduct long after the fact. This is neither fair, nor appropriate.

(2) Service Quality

61. EP acknowledges that the Applicant has met or exceeded all of the service quality indicators from 2010 through 2013. No other party raised any concerns about service quality, which in all cases have meet or exceeded industry targets.

(3) Reliability Performance

62. EP notes that CND's reliability performance has deteriorated in terms of both SAIDI and SAIFI between 2008 and 2012. In this context, EP argues that CND "put off spending on reliability until the rebasing application" and that "this type of gaming of the incentive regulation mechanism does not support the application."[16]

63. EP has provided no evidence to support this allegation. This is because the allegation is not supported by the evidence. As is illustrated in Table 1 above, CND's reliability spending (which in this case must mean OM&A spending, since capital is settled) increased consistently between 2010 and 2014 year-over-year during the entire 3GIRM

[16] EP Final Argument at pg. 6.

term. The costs are not loaded into the test year, and in-fact the test-year increase in OM&A is the smallest increase of any other year during the 3GIRM term.

64. EP also argues that CND did not provide any benchmarking of its reliability results with other comparable distributors. It is unclear what this type of comparison – which EP could have easily done itself with reference to the yearbook for electricity distributors if it had a specific concern – would add to the analysis. The Board has determined that an LDC's reliability performance should remain within at least its historical 3-year performance range. The evidence is that CND is above the Board standard for both SAIDI and SAIFI in 2012 but the trend is negative.[17]

(4) <u>Efficiency Benchmarking</u>

65. EP argues that "CNDHI has moved in the wrong direction over the IRM period. This does not support the application which includes a further significant increase in OM&A costs while not providing the results one would expect from an efficient distributor."

66. Efficiency benchmarking is not static and some movement between efficiency cohorts is to be expected. Minor modifications in the efficiency modelling can lead to migration from one cohort to another. Regardless of the cause, what is important is that when CND moved from cohort 1 to cohort 2 between 2010 and 2011, the stretch factor applicable to CND increased. This created an increased financial incentive on CND to continue to improve efficiency performance. The Board's IRM construct worked exactly as it should have. A change in cohort that occurred in 2010 is not grounds to justify an arbitrary reduction in OM&A cost in the test year. While still included in the middle cohort, it is worth noting that CND is performing among the best – not the worst - in this cohort with an average cost of 7 percent below PEG's model prediction.

B.5 Public Policy Responsiveness (Issue 5.1)

67. The Applicant addressed this partially settled issue in its AIC.[18] In this context, EP disputes the costs associated with meeting these obligations. In EP's view these costs are not reasonable. EP elaborates on this view in respect of issues 4.2 and 7.4, so we will respond to EP's view in this regard in respect of the OM&A area of dispute below.

[17] Exhibit 2, Tab 3, Schedule 1, Page 9.
[18] Transcript Volume 2 dated April 30, 2014 at pg. 15 at line 8 to pg. 16 at line 8.

B.6 Financial Performance (Issue 6.1)

68. EP argues that "the lack of planning for long term debt puts CNDHI's financial viability at risk over the longer term."[19]

69. The Applicant strongly disagrees with this suggestion. As is described in greater detail in respect of the long-term debt area of dispute below, it is not the case that CND has no plan or suffers from a "lack of planning for long term debt". Rather, EP is simply not happy with CND's plan to defer the acquisition of new long-term debt beyond the test year.

70. But that decision does not, in any way, put CND's financial viability at risk. To be perfectly clear: at no time would the Applicant propose a financing strategy that would put the financial viability of the utility at risk. The evidence on the record about the ongoing financial viability of the utility was canvassed in AIC, and confirms that CND's long-term financial viability remains secure.[20]

71. In this context, EP suggests that CND's "actual capital structure is significantly different from its deemed structure, particularly with respect to long term debt. The deemed component of long term debt is 56%, while its actual level is 29%. (Tr. Vol. 1, page 46) This translates into a shortfall in actual long term debt of about $35 million."[21]

72. So as to avoid the duplication which appears in EP's submissions - CND will address this particular submission once in greater detail below in respect of the cost of long-term debt area of dispute below. It is sufficient to say at this stage that the EP numbers are very misleading and they do not reflect the actual debt-to-equity split for CND.

73. EP goes on to speculate that "long term rates are at a historic low" and that CND is "failing to meet its obligations to its customers" by failing to borrow money in the test year. CND addresses this interest rate speculation in respect of the cost of long-term debt area of dispute below. Put simply, EP does not produce any compelling evidence or analysis to support its assertion that interest rates are at an all-time low.

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[19] EP Argument at pg. 17.
[20] Transcript Volume 2 dated April 30, 2014 at pg. 16 at line 9 to pg. 17 at line 9.
[21] EP Argument at pg. 17.

74. In any event, under no circumstances will the difference between borrowing in the test year at market rates or borrowing in the future at market rates (regardless of which way interest rates happen to shift) affect the ongoing financial viability of the Applicant.

C. OM&A

75. CND has been candid and upfront about its OM&A proposal in the Application.

76. Mr. Ian Miles, the President and CEO of CND, stated clearly and unambiguously in examination-in-chief:

> "Exhibit 4 of our prefiled evidence contains a good overview of our OM&A costs dating back to the last Board-approved level in 2010.
>
> As this evidence shows, there has been significant increase in OM&A during that time period.
>
> CND is requesting 2014 OM&A, as adjusted, of $15,033,000, which represents about an 8 percent increase over our 2013 actuals."[22]

77. Mr. Miles went on to identify a number of industry-wide cost drivers[23] which have driven this increase between 2010-2014, which he readily admits are not unique to CND and which are demanding more from the Applicant.

78. In Table 1 above, we have shown that the CND response to these industry wide cost drivers is not inconsistent with what the Board has approved in terms of OM&A cost increases in the Board's recent Decisions for Kitchener-Wilmot and Oakville Hydro.

79. Mr. Miles also identified a number of additional cost drivers that are unique to CND that were discovered after the organization undertook a comprehensive risk assessment and business planning process in the fall of 2012. The key priorities which arose for CND as a result of this process included addressing inadequate resourcing in the IT department, addressing inadequate control room resourcing, and succession planning.

80. In light of this evidence:

   a. SEC recommends a reduction in the OM&A component of revenue requirement of $1.5 million.[24] SEC indicates that there was "no magic to the amount" but it

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[22] Transcript Volume 1 dated April 29, 2014 at pg. 26 line 18-25.
[23] Exhibit 4, Tab 2, Schedule 1.
[24] SEC Final Argument at para. 2.2.12.

appears to have been determined based on a formulaic approach allowing for a 15% increase in 2010 OM&A amounts.

b. EP recommends a reduction in OM&A of $1.1 million in the test year, which is also premised on a formulaic approach to OM&A based on a 4.5% increase over normalized historic costs.[25]

c. Staff recommends a reduction of OM&A of $680,000 in the test year, which is premised on a formulaic approach to OM&A based on a 5% increase over normalized historic costs.[26]

d. VECC recommends that CND's OM&A expense be reduced to 2013 actuals for the 2014 test year.[27]

81. The Applicant's direct reply to these suggestions is set out herein.

C.1 The Parties underestimate the magnitude of the impact of the underlying cost drivers on LDCs – as illustrated by two very recent Board decisions.

82. Each of the Parties' submissions imply a concern that the Applicant's OM&A costs are increasing too fast and consequently the request is for the Board to impose constraint in the manner of a reduction in the test year OM&A budget.

83. However, none of the Parties acknowledge the full magnitude of the impact of the cost drivers faced by many LDCs over the 2010-2014 period, including the Applicant, in respect of annual wage increases largely driven through the collective bargaining process (not solely in management's control), substantial increases in pension and benefit costs (outside of management's control), the need to address an aging workforce through succession planning (a widely understood challenge that others would argue management is imprudent if they failed to address), and increased regulatory costs including the need for additional organizational capacity to respond to numerous incremental regulatory obligations (compliance with these obligations is not discretionary).

84. In this context, the Parties cite a number of past Decisions which they argue are supportive of their formulaic approach to OM&A expenses. However, as described

[25] EP Argument at pg. 12.
[26] Staff Submissions at pg. 5.
[27] VECC Final Argument at pg. 6.

earlier in these reply submissions, none of these Decisions are analogous to this Application because (1) none were made in respect of the same time period in question (2010-2014) and therefore the underlying cost drivers are factually different that those identified in the Application; and (2) none were made under the Board's RRFE which is an outcome oriented form of regulation focused on sustainable long-term operational efficiencies not short-term cost cutting.

85. In Table 1 above the Applicant has identified two more recent Board decisions in respect of the same time period in question (2010-2014) and has summarized the evidence of the OM&A cost increases in those cases over the same period and compared those increases to those proposed by the Applicant.

86. The results are telling. Far from being an outlier in terms of OM&A cost increases over the 2010-2014 period - the Applicant's OM&A cost increases are quite consistent with the Board approved OM&A cost increases for other LDCs over the same period of time. Specifically, CND's OM&A cost increase between 2010-2014 (a total increase of 55.29%) is entirely consistent with the OM&A increases the Board has recently approved for both KW (a total increase of 49.78%) and Oakville (a total increase of 59.74%).

C.2 Management has already undertaken comprehensive budgeting, cost management and benchmarking efforts which is detailed on the evidence.

87. The Applicant's comprehensive risk management and strategic planning process included a measured approach to budgeting and cost management, the intent of which was to limit rate impacts.

88. Specifically, in response to 1.1-SEC-1, the Applicant filed its original 2013-2014 budget approved by its Board of Directors in January 2013 as well as its revised 2014 budget, which was prepared for the purposes of this Application, and was approved by its Board of Directors in September 2013. Following a discussion of cost drivers and key risks – a discussion of rate impacts features prominently in both the January 2013 and September 2013 budget presentations. Rate impacts are a key feature of both covering memorandums as well.

89. This should not be surprising. Minimizing rate impacts, to the extent reasonably possible, is a core concern for both CND's management and its Board of Directors.

90. There are numerous examples in the evidence of management's cost management efforts which will flow to the benefit of ratepayers. In the terminology of the RRFE – management's focus is on pursuing operational effectiveness initiatives that will deliver long-term sustainable savings for ratepayers. Many operational effectiveness initiatives were undertaken prior to the test year, and are already incorporated in current cost forecasts (since those initiatives are not separable from the cost of providing service). The operational effectiveness initiatives that are being undertaken in the test year are set out in considerable detail in AIC - and we will not repeat them again now.[28]

91. Some of these operational effectiveness initiatives will result in benefits for ratepayers in the test year. These include a $117,600 reduction to OM&A in the test year, resulting from a 16% reduction in health and dental benefits costs arising following a joint review of these costs undertaken by the 10 member LDCs of the GridSmartCity initiative.[29]

92. Unfortunately, not all operational effectiveness initiatives will lead to such prompt, direct and measureable OM&A reductions. Other operational effectiveness initiatives being undertaken in the test year will lead to ratepayer benefits in the future during the term of the 4GIRM plan. As previously discussed, the Board has built an expectation of these efficiency initiatives being undertaken directly into its 4GIRM rate-setting methodology. During the 4GIRM term, the Applicant bears all of the risk if it fails to achieve the necessary productivity improvements. Ratepayers gain the benefit of the stretch factor and productivity factor – providing a strong incentive on the Applicant to achieve these efficiencies. And at the end of the IRM term, ratepayers gain the full benefit of all productivity improvements which will be incorporated directly into cost forecasts.

C.3 The Important Role of Benchmarking

93. As discussed in AIC,[30] benchmarking also played a very important role in the Applicant's budgeting process. The September 2013 budget presentation includes a benchmarking comparison of the Applicant's rates against those of three neighbouring LDCs – Kitchener, Waterloo North and Guelph.

[28] Transcript Volume 2 dated April 30, 2014 at pg. 10 at line 21 to pg. 15 at line 6.
[29] 7.4-VECC-32.
[30] Transcript Volume 2 pg. 17 at line 10 to pg. 18 at line 26.

94. A key prerogative of management and the Board of Directors is to ensure that any proposed budget results in CND maintaining comparable rates with neighbouring, similarly situated, LDCs.

95. Benchmarking also features prominently in the Application. In an update in response to a request by SEC, CND provides a rate comparison to its neighbouring LDCs for the Residential, GS <50 and GS >50 classes. This comparison is reproduced in Table 2 below for ease of reference.

96. What is readily apparent is that after the Application, CND rates for all three rate classes remain comparable to each of its neighbouring LDCs.

Table 2: Benchmarking Comparison to Neighbouring LDCs (from 2.1-SEC-15)

Revised Table 1-2 Distribution Rate Comparative with Neighbouring LDCs

Residential at 800 kWh

2013 Distribution Rates	CND 2014 Proposed	CND Current	Kitchener	Waterloo	Guelph
Service Charge	$ 13.32	$ 10.09	$ 9.76	$ 14.79	$ 14.10
Distribution Variable	$ 12.96	$ 13.04	$ 13.84	$ 14.96	$ 13.76
Total Fixed and Variable	**$ 26.28**	**$ 23.13**	**$ 23.60**	**$ 29.75**	**$ 27.86**

GS<50kW at 2,000 kWh

2013 Distribution Rates	CND 2014 Proposed	CND Current	Kitchener	Waterloo	Guelph
Service Charge	$ 18.48	$ 11.92	$ 25.71	$ 31.11	$ 15.16
Distribution Variable	$ 25.80	$ 25.40	$ 24.80	$ 27.80	$ 25.40
Total Fixed and Variable	**$ 44.28**	**$ 37.32**	**$ 50.51**	**$ 58.91**	**$ 40.56**

GS 50-999 kW at 250 kW

2013 Distribution Rates	CND 2014 Proposed	CND Current	Kitchener	Waterloo	Guelph
Service Charge	$ 126.44	$ 109.35	$ 237.72	$ 116.22	$ 164.36
Distribution Variable	$ 1,060.73	$ 920.85	$ 1,014.83	$ 1,153.53	$ 626.73
Total Fixed and Variable	**$ 1,187.17**	**$ 1,030.20**	**$ 1,252.55**	**$ 1,269.75**	**$ 791.09**

97. This conclusion is consistent with the conclusions presented by SEC in its Final Argument in respect of the Residential and GS <50 classes.[31]

98. However, SEC's conclusion that CND's rates are significantly higher than average in respect of the GS > 50 class is misleading. This is because SEC has included in its comparison of rates a number of LDCs that are not comparable to CND in terms of size and service area (Horizon, Halton Hills and Milton) and utilities that do not have comparable rate classes (Burlington has one rate class for all large customers - GS>50 -

[31] SEC Final Argument at para. 1.2.4.

while CND divides these customers up into three rate classes - GS>50, GS 1000-4999 and Large User). As a result, SEC is not using like-for-like comparisons. If these four problematic comparisons are removed from SEC's table, then much like Table 2 above, it is clear that CNDs GS > 50 rates are also comparable to those of neighbouring LDCs.

C.4 The consequences of the OM&A reductions proposed by the Parties will be short-term cost cutting, not long-term savings resulting from operational effectiveness initiatives.

99. The OM&A cuts that are being proposed by the Parties will not drive long-term or sustainable efficiencies. Rather they will result in short-term cost cutting that will reduce the ability of management to implement the specific operational programs identified throughout the Application. In short - management will be required to do less with less.

100. While the Applicant's OM&A costs in 2013 (actuals) were $13,807,478,[32] this amount does not accurately represent a starting point for 2014 because only a portion of the salaries for the FTEs added during 2013 are reflected. One would need to increase this amount by approximately $700,000 to reflect the full-year costs of these employees in 2014. And this does not account for the annual increases arising from a variety of other non-discretionary cost drivers.

101. In particular, various Parties have raised concerns about the growth in the number of FTEs between 2010 and 2014. Staff mistakenly indicates that "[s]ince 2010, year-end positions for FTE's have grown from 59 in 2010 to 109 in 2013 and CND is planning to have 117 by year-end 2014."[33] This is not factually correct. If one refers to 4.2-EP-16, one will see that the number of FTEs have grown from **89** in 2010, to 109 in 2013, and 117 by year-end 2014. Staff's submissions have the effect of greatly exaggerating the growth in FTEs since 2010. In this context, the Parties appear to ignore the evidence on the record about the key drivers behind each of these FTEs, including the need for incremental capacity to address customer growth, the introduction of smart meters/TOU, mandatory CDM targets and other new regulatory requirements, enhanced system

[32] Undertaking J1.5.
[33] Board Staff Submissions at pg. 4.

maintenance, improved governance, and the need to bring on new hires now to be trained for succession planning purposes in advance of expected retirements.[34]

102. Because of the magnitude of the reductions in OM&A proposed by the Parties, the Applicant would have to undertake serious cost-cutting efforts which may, depending on the depth of the cuts, include:

   a. the suspension of all remaining new hires for 2014 (including two new apprentices required for succession planning purposes) as well as the suspension of the hiring of certain 2013 positions that have not yet been filled (one control room operator and a credit and collections supervisor);

   b. the cancellation of the 24/7 control room operations (one of the key areas of risk the Applicant identified in examination-in-chief, that it is required to bring the Applicant into compliance with IESO load-shedding requirements,[35] and was being implemented partly because 9 out of 10 large institutional customers indicated it is important to be able to contact CND 24 hours a day, seven days a week (Exhibit 1, Appendix 1-1B, pg. 36 of 43));

   c. the deferral of many, if not all initiatives in 2014, including in respect of disaster recovery planning, training and development of employees, and building maintenance (which is a risk in light of the ageing building); and

   d. the layoff of existing staff (who are already trained and operational, and which may result in severance payments as well).

103. The Applicant submits that, in the context of the RRFE focus on long-term and sustainable operational effectiveness, and the Applicant's proven efficiency performance in the PEG benchmarking, this short-term cost cutting is not in the public interest. It would result in a decreased quality of service, and would leave many of the key areas of risks identified during the comprehensive risk assessment process unaddressed.

[34] 6.2-VECC-30.
[35] Transcript Volume 1 dated April 29, 2014 at pg. 29 at line 2 to pg. 30 at line 14.

D. D. COST OF CAPITAL – LONG TERM DEBT COMPONENT

104. Staff raised no concerns with the Applicant's proposal in respect of long term debt costs as it is consistent with Board policy in this area.[36]

105. In this context SEC and EP, supported by VECC, recommend a fundamental departure from Board's policy as it relates to the determination of the cost of long term debt.

106. Specifically, SEC argues that "the just and reasonable result is to assume the deemed debt, but assume for calculation purposes that the incremental deemed debt is borrowed at prevailing interest rates, not higher past interest rates. This would reduce revenue requirement by about $400,000."[37]

107. EP provides a more specific recommendation, which appears to be consistent with what SEC is arguing for. Specifically, EP argues that "the Board should impute the addition of $30 million in long term debt for the 2014 test year" and "the appropriate rate to be used would be 3.75%" and "[i]f this additional $30 million at a rate of 3.75% is included in the calculation of the long term debt rate, this rate declines from 4.96% to about 4.44%. When this differences is applied to the deemed long term debt of $73,252,142 (RRWF in the Settlement Agreement), this results in a reduction in long term debt costs to be paid for by ratepayers of approximately $390,000."[38]

D.1 The Parties recommending a departure from Board policy must produce evidence sufficient to satisfy the burden of proof that such a departure is warranted in the circumstances (see citations below). EP and SEC both fail in this regard.

108. CND disagrees with the EP and SEC recommendation. It is inconsistent with Board policy on the calculation of cost of capital. The premise underlying both the EP and SEC submissions is that the application of the Board's policy on cost of capital will not result in "just and reasonable rates" in this case. The only evidence they marshal in support of this position is to say that if the Board abandoned its policy as they suggest, it would result in lower rates.

109. This is not the first time that these intervenors have sought to challenge the Board's policy on cost of capital. We would refer the panel to two decisions on similar cost of

[36] Board Staff Submissions at pg. 1.
[37] SEC Final Argument at para. 3.2.5.
[38] EP Final Argument at pgs. 20 and 21.

capital concerns raised by the intervenors: (i) the Board’s Decision and Order in EB-2009-0139 dated April 9, 2010; and (ii) the Board’s Decision and Order in EB-2009-0259 dated March 1, 2010. The principle established by the Board in these cases is that the party proposing a departure from the Board's policy on cost of capital must support it with evidence (at pg. 12 of EB-2009-0139 and pg. 18 of EB-2009-0259).

110. Both EP and SEC both fail on this account. SEC offers no rational to support its recommended adjustment other than to assert that it is required to result in “just and reasonable rates”.

111. EP argues that the Applicant’s approach to financing results in “an inappropriate outcome of CNDHI’s failure to properly plan the financial management of its assets and ignores the benefits of locking in long term rates at historically low levels at a time when these rates are expected to increase in the future. It ignores the customer focus and customer engagement results that overwhelmingly tell the distributor, and the Ontario Energy Board, that the number one concern of ratepayers is better prices/lower rates.”[39]

112. Put simply – the allegation appears to be that the Applicant is not managing its financing needs in a prudent manner and that the Board should substitute its judgement for that of management.

113. The allegation is premised on conjecture and speculation and is not supported by the facts. The evidence speaks for itself. The parties reached agreement on the Applicant’s capital plan (Appendix C in the Settlement Proposal) and knowing its needs management made a determination on its approach to finance those needs. This approach is explained in detail in the AIC and is clear, cogent and represents good business practice in the circumstances.[40] We will not repeat the evidence and approach again here.

114. Rather we will assume – without agreeing – that the Applicant did what EP and SEC is asking and procured approximately $30,000,000 in new long-term debt at a rate of 3.75% in the test year. The evidence is clear, CND does not actually need this amount of long term debt to meet its financing needs in the test year.[41] However, there would be an

[39] EP Final Argument at pg. 21.
[40] Transcript Volume 2 dated April 30, 2014 at pg. 19 at line 15 to pg. 22 at line 11.
[41] 7.5-EP-30(b).

immediate adverse financial consequence for the utility. Specifically, CND would have to pay $1,125,000 in total annual interest charges (3.75% x $30,000,000) each year on a going forward basis. As a result, management would have to pay a sizeable incremental interest expense when the funds gained by the new long-term debt are not actually needed in the test year. This would have a direct and negative impact on the quality of service that CND is able to provide to its customers. CND management determined that such a negative impact was not in the best interests of ratepayers or the utility – and was not consistent with prudent financial management.

115. Prudent management also needs to consider what happens if EP's speculation that today's rates are at "historically low levels" turns out to be wrong and lower rates are available in the future. If that is the case, then management would end up locked into a long-term debt instrument that isn't needed in the immediate term and that requires higher interest payments over the life of the instrument than would have applied had management simply deferred its financing efforts until the debt was actually needed. This is why unproven speculation about current versus future interest rates should not dictate financing decisions.

116. In this context it is worth noting that SEC concedes the point that "[w]hile we agree with Energy Probe that management is taking a risk on interest rates, it is not sufficiently obvious to us that this is wrong for us to recommend it be treated as imprudent."[42]

D.2 There is no requirement in Board policy for the actual capital structure to be the same as the deemed capital structure. CND's actual debt-to-equity split is 51%-49%, which is simply not sufficiently deviant to merit imputing new long-term debt.

117. EP argues that "the actual long term debt represents only 29% of rate base in the 2014 test year, significantly below the deemed long term debt component of 56%. This represents a $35 million shortfall in deemed debt as compared to actual debt."[43]

118. This is misleading. It does not compare the actual liabilities to the actual equity of the utility to compute an actual debt-to-equity split (which if EP did this, they would note that CND has an actual capital structure that reflects a 51%-49% debt to equity split based on the most recent (2012) OEB year-book information).

[42] SEC Final Argument at para. 3.2.3.
[43] EP Argument at pg. 19.

119. Rather, EP compares the actual long term debt amount to the deemed debt component of rate base the latter of which is calculated for regulatory ratemaking purposes. This is akin to comparing apples (an actual balance sheet amount) with oranges (a deemed amount calculated for regulatory and rate making purposes).

120. By way of illustration, for ratemaking purposes the entire capital structure of the utility is assumed to consist of equity and debt, and within the debt component there is assumed to be long-term and short-term debt. By contrast, the actual liability portion of the balance sheet includes much more than long term and short term debt components assumed for ratemaking purposes. Specifically, actual liabilities include accounts payable & accrued charges, other current liabilities, inter-company payables, loans and notes payable, and current portion of long term debt, long-term debt, inter-company long-term debt & advances, regulatory liabilities (net), other deferred amounts & customer deposits, employee future benefits, and deferred taxes.

121. Because of the differences between the deemed and actual capital structures, and EP acknowledges this, "there is no requirement for the actual capital structure to be the same as the deemed capital structure."[44] This is an accurate statement of Board policy.

122. The consequence of this policy is reflected in the wide variance in actual debt-to-equity splits among LDCs in Ontario. We have produced a comparison of LDC actual vs. deemed capital structure in Appendix "A". The Applicant is far from an outlier among other LDCs, specifically the Applicant is among 52 of 75 LDCs that are all within plus or minus 10% of the Board's deemed debt-to-equity ratio. Given this, there is no evidence to justify the Board imputing any new long-term debt as recommended by SEC and EP. The Applicant is in no way an outlier in this regard.

123. In this context, EP's suggestion that under the RRFE the Board should correct for any deviation from the deemed capital structure for the purposes of the determination of the appropriate revenue requirement – represents a fundamental departure from Board's established policy on cost of capital. As noted in Appendix "A" such an approach would have profound impacts not just on the Applicant, but almost every other LDC. Any such

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[44] Ibid.

fundamental change to the Board's policy on cost of capital should not be made in the context of this case – but as part of a broader public consultation where all interested parties would have proper notice to participate.

124. Finally, and strictly in the alternative if the Board does opt to permit a departure from its policy on the determination of cost of capital, CND submits that the interest rate applicable to any such deemed or imputed long-term debt should be the Board's long-term debt rate of 4.88%. There is no basis in fact (no actual debt instrument) to support the use of a rate of 3.75% as proposed by EP.

E. OTHER REVENUES – INTEREST INCOME

125. Staff raised no concerns with the Applicant's proposal in respect of interest income as it is consistent with Board policy in this area.[45]

126. SEC implies that they would like to see interest income increased on the basis that "the incremental cash that would result from the deemed debt model was actually being invested" but SEC acknowledges that "that would appear to us to be a step to far."[46] It is several steps too far in the Applicant's view.

127. In this context, EP takes the view that: (1) the average bank balance in 2014 should be recalculated to $5.9 million, and (2) the average interest rate should be reduced to 1.30% earned in 2013.

128. EP justifies the increase in the average bank balance in 2014 on the basis that the Applicant did not borrow any additional long-term debt in 2012-2013, that the decline in the closing balance between 2012 and 2013 was $5.8 million, and that therefore the closing balance in 2014 should increase to reflect this historic experience.

129. CND disagrees. The evidence is clear that "CND has not forecasted any incremental third party long-term debt in 2014 Test Year as CND expects that it will be able to fund its capital expenditures in 2014 with its cash flow from operations, existing cash and cash equivalents, and short-term bank indebtedness. As at December 31, 2013, CND had

[45] Board Staff Submissions at pg. 1.
[46] SEC Final Argument at pg. 3.3.2.

approximately $8.8MM in cash and cash equivalents and also has available to it an $8MM operating line of credit."[47]

130. Under the approved Settlement Proposal, CND will need to fund $15 million in capital in the test year plus an approximately $1.9 million dividend (for a total of $16.9 million). From a cash-flow perspective, these expenditures will be funded using $5.5 million funds from operations, $8.8 million in cash and cash equivalents, and the balance will be funded through short-term bank indebtedness. This funding approach was initially laid out in the Applicant's cash flow plan which was filed in response to 1.1-SEC-1 (at page 203 of the interrogatory responses) and was explored further by SEC during cross-examination.[48] In conclusion, even after accounting for the reduction in capital spending arising as a result of the Settlement Proposal - the entire amount of $8.8 million in cash and cash equivalents will be utilized during the test year. There simply will not be any cash left in this account at year-end.

131. Given this, it is entirely reasonable that the Applicant is forecasting a $0 closing balance in this account in the test year. If the Applicant were to maintain a closing balance of $3.3 million, as suggested by EP, that $3.3 million would need to be funded through short term bank indebtedness. CND would then pay interest on this indebtedness to the bank at a much higher rate than the interest CND would earn by maintaining the account at a balance of $3.3 million. This is not a prudent financing strategy and is not in the public interest.

132. To justify the increase in the applicable interest rate to 1.30%, EP argues that there is no evidence to support a reduction in the average interest rate in the test year relative to the 1.30% earned in 2013.

133. This is misleading. EP has chosen to ignore the evidence that is on the record – which EP itself elicited during cross-examination. Specifically:

> "MR. AIKEN: How did you come up with the forecast of 1.13 percent for 2014?

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[47] 7.5-EP-30(b).

[48] Transcript Volume 1 dated April 29, 2014 at pg. 118 at line 12 to pg. 119 at line 5.

> MS. HUGHES: So the forecast is based on the estimated cash flow throughout the period. The reason why the interest rate would change is our banking arrangement has a fluctuating interest based on the level of cash.
>
> So on cash in excess of -- I believe it is 5 million, there is a higher rate of interest, and so as cash now comes down, the interest that we would be earning on that cash flow would be less.
>
> MR. AIKEN: Can you provide what the rates are, what the current rates are in your bank account in these different tiers?
>
> MS. HUGHES: I could. I have that...
>
> MR. BROOKER: Yes. I have the information. The balance from zero to 5 million is 1.15 percent.
>
> MS. HUGHES: It's prime minus.
>
> MR. BROOKER: Yes, it's Royal Bank prime minus 1.85 percent.
>
> At the end of February, which is the latest one that I have in front of me, that works out to a balance of 1.15 percent.
>
> And the amount for amounts over -- 5 million and over is the Royal Bank prime 1.75 -- sorry, Royal Bank prime minus 1.75 is 1.25 percent.
>
> MR. AIKEN: Thank you."[49]

134. The evidence is clear. The interest rate on the banking arrangement has a fluctuating interest rate. It varies based on the Royal Bank prime rate – which as noted in the excerpt above – has gone down since 2013. And it varies based on the level of cash in the account. In the circumstances, CND's forecasted rate of 1.13% is appropriate.

F. RATE DESIGN (FIXED/VARIABLE SPLIT) FOR THE GS > 50KW CLASS

135. In the AIC, the Applicant explained its principled approach to setting the fixed/variable split for the GS > 50 kW rate class on the same basis as settlement was reached for all other rate classes in respect of issue 8.3.[50] That principle is that the proposed fixed and variable splits for all rate classes in the 2014 test year, including the GS>50kW class, should be computed on the basis of holding the ratio constant based on 2013 levels. This approach was calculated in response to 8.3-EP-42 and formed the basis of settlement on all other rate classes in Appendix F of the Settlement Proposal.

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[49] Transcript Volume 1 dated April 29, 2013 at pg. 49 at line 10 to pg. 50 at line 7.
[50] Transcript Volume 2 dated April 30, 2014 at pg. 24 at line 20 to pg. 28 at line 16.

136. Staff, EP and SEC now take the view that the GS>50kW rate class should be treated differently than all other rate classes – specifically that the fixed charge for this class should be maintained at $109.35 rather than being increased to $126.44.

137. The principle underpinning this approach is described by EP that "the fixed component of the distribution rate should be capped at the higher of the previous approved charge and the ceiling calculated from the current cost allocation model. There is no reason that the fixed charge for any rate class should exceed the ceiling for that class if it was below the ceiling to begin with and there is no reason why the fixed charge should increase further if it already above the ceiling."[51]

138. While it sounds reasonable on the surface - the Parties appear to be picking which rate classes this new principle should apply to and ignoring other rate classes in identical circumstances. In the Applicant's view, rate design principles should be applied consistently across all rate classes. Otherwise the Board risks allowing some rate classes to gain the benefit of a lower fixed cost because they are directly represented by a Party in the hearing process, while other rate classes are ignored. This approach to rate design is not, in the Applicant's view, in the public interest.

139. We have reproduced Appendix F from the approved Settlement Proposal to illustrate the rationale for the Applicant's concern.[52] Notably, the table shows a column both for the original Application (Fixed Charge for 2014 as Proposed) and as adjusted to reflect the settlement (Proposed Fixed Charges at Settlement).[53]

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[51] EP Final Argument at pg. 22.

[52] For the sake of clarity, the rates in this table as well as the cost allocations have not, to-date, been updated to reflect the settlement – rather the Applicant will complete such updates once the Board makes its final determination on the remaining areas of dispute.

[53] It is worth noting that the actual numbers in this table will likely change for the final rate order, depending on the Board's final determination on the other areas in dispute in this proceeding.

Table 3: Appendix F from the Approved Settlement Proposal.

Appendix F Settled and Partially Settled Fixed and Variable Splits

FIXED CHARGE ANALYSIS													
Customer Class	2013 Rates from OEB Approved Tariff	Current Fixed Split	Current Variable Split	Total	2014 Fixed Rate Based on Current F/V Revenue Proportions	Proposed Fixed Split	Proposed Variable Split	Total	Fixed Charge for 2014 as Proposed	Ceiling Fixed Charges from Cost Allocation Study	Floor Fixed Charges from Cost Allocation Study	Proposed Fixed Charges at Settlement	
Residential	$10.09	47%	53%	100%	$11.58	55%	45%	100%	$13.32	$16.55	$4.35	$11.58	
GS <50 kW	$11.92	26%	74%	100%	$13.78	35%	65%	100%	$18.48	$25.03	$9.49	$13.78	
GS 50-999 kW	$109.35	19%	81%	100%	$126.44	19%	81%	100%	$126.44	$96.99	$48.84	$126.44	Not Settled
GS1000-4999 kW	$908.75	18%	82%	100%	$1,050.20	18%	82%	100%	$1,050.20	$317.41	$47.52	$1,050.20	
Large Use	$7,785.09	20%	80%	100%	$8,998.17	20%	80%	100%	$8,998.17	$883.34	$556.68	$8,998.17	
Street Lighting	$2.04	49%	51%	100%	$2.75	49%	51%	100%	$2.75	$8.55	$0.13	$2.75	
USL	$7.07	61%	39%	100%	$6.39	61%	39%	100%	$6.39	$5.43	$0.11	$6.39	
Embedded Distributors	n/a	0%	100%	100%	n/a	0%	100%	100%	n/a	n/a	n/a	n/a	

140. As Staff correctly note in their submissions – by maintaining the fixed and variable split for the GS>50kW rate class, the Applicant's proposal will result in the fixed charge for the GS>50kW rate class increasing from $109.35 to $126.44 – which is above the ceiling of $96.99 found in the updated cost allocation study. This is illustrated in Table 3 above.

141. However, as shown in Table 3, this situation is <u>identical</u> for the GS1000-4999kW rate class and the Large Use rate class.

142. Specifically, by maintaining the fixed and variable split for the GS1000-4999kW rate class, the Settlement Proposal resulted in the fixed charge for this rate class increasing from $908.75 to $1,050.20 – which is above the ceiling of $317.41 found in the updated cost allocation study.

143. And by maintaining the fixed and variable split for the Large Use rate class, the Settlement Proposal resulted in the fixed charge for this rate class increasing from $7,785.09 to $8,998.17 – which is above the ceiling of $883.34 found in the updated cost allocation study.

144. Staff argue that "it is the Board's policy not to permit movement further away from the ceiling." However, Staff did not raise this policy issue to the attention of the Board in their submissions on the Settlement Proposal in respect of the proposed settlement for the Large Use and GS1000-4999kW rate classes.

145. The reason is that the Board policy and past practice in this regard is simply not as cut-and-dry as is suggested by Staff in their submissions. In-fact, since November 28, 2007 report was issued, the Board has frequently approved rate design proposals which do allow the fixed charge to increase further above the ceiling in circumstances where the Applicant is proposing to maintain the same fixed and variable split for that rate class.

146. To illustrate this point, after conducting a brief review of prior Board decisions, the Applicant has identified six cases where an approach <u>exactly analogous</u> to what is being proposed by the Applicant was accepted by the Board for one or more rate classes:

   a. Centre Wellington Hydro Ltd. - 2013 Cost of Service Rate (EB-2012-0113)

   b. Atikokan Hydro Inc. - 2012 Cost of Service Rate (EB-2011-0293)

   c. Espanola Regional Hydro Distribution Corporation - 2012 Cost of Service Rate (EB-2011-0319)

   d. Horizon Utilities Corporation - 2011 Cost of Service application (EB-2010-0131)

   e. Hydro One Brampton Networks Inc. - 2011 Cost of Service application (EB-2010-0132)

   f. Kenora Hydro Electric Corporation Ltd.- 2011 Cost of Service application (EB-2010-0135)

147. This list is not intended to be exhaustive, simply illustrative of the practical approach taken by the Board and the Parties in prior decisions.

148. This practical reality is why all of the Parties (excluding Staff) were able to reach settlement on the Applicant's proposed approach to maintain the fixed and variable split the same for the Large Use and GS1000-4999kW rate classes. This practical reality also explains why Staff likely endorsed the proposed settlement without raising any policy concerns to the attention to the Board.

149. In this circumstance, the Applicant does not believe it is appropriate to apply a fundamentally different approach to rate design to the GS>50kW rate class when a different, consistent and principled based approach has been settled upon and approved

by the Board for all other rate classes including two other classes in analogous circumstances.

150. Finally, and as mentioned in AIC, the Applicant's approach to rate design is consistent with the Board's new policy approach on rate design as set out in the Board's March 31, 2014 draft report in EB-2012-0140 that:

> "The Board believes that a fixed rate design for the recovery of electricity distribution costs is the most effective rate design for ensuring that rates reflect the cost drivers for the distribution system and best respond to the current environment."

G. REMOVAL COSTS

G.1 Should the removal costs incurred in 2012 and 2013 be included in Account 1576?

151. Board Staff takes the view that "removal costs incurred by CND in 2012 and 2013 should not be included in account 1576 because the change in their treatment was not one that is properly characterized as a change in capitalization policy."[54]

152. Staff provide five main reasons to support this view.

153. First, Staff makes reference to the Report of the Board titled '*Transition to International Financial Reporting Standards*' EB-2008-0408 dated July 28, 2009 (the "**2009 Board Report**"). Specifically, Staff argues that: "Issue 3.3 regarding capitalization in the 2009 Board Report specifically addressed the fact that IFRS permits less capitalization of indirect overhead and administration costs than is permitted under CGAAP. Issue 3.4 of the 2009 Board Report listed other PP&E related items that may be affected by the transition to IFRS, including gain and losses on disposition of assets, asset retirement obligations etc."[55]

154. CND carefully considered the 2009 Board Report prior to filing its Application and, for the reasons that follow, respectfully disagrees with Staff's very narrow interpretation of allowable changes in capitalization policies.

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[54] Board Staff Submissions at pg. 7.
[55] Board Staff Submissions at pg. 7.

155. Issue 3.3 of the 2009 Board Report (at page 15) states (emphasis added): "Should the Board require PP&E to conform to IFRS capitalization requirements (**e.g. capitalize less indirect overhead and administration cost than permitted under current Canadian GAAP**)?" The words highlighted in bold and underlined are prefaced by the letters "e.g.", and thus are intended as an illustrative example of one type of change of capitalization policy. But this is not an exclusive or exhaustive list (which the letters "i.e." may have implied, had they been used), and does not have the effect of excluding other changes in capitalization policies to conform to IFRS capitalization requirements – such as in CND's case - changes relating to the capitalization of removal costs.

156. The 2009 Board Report was focused on major points of departure between existing regulatory accounting and rate making as compared to IFRS. This is the main heading at pg. 10 of the 2009 Board Report – which goes on to state that (emphasis added) "the Board is satisfied that this consultation has enabled it to identify and address the areas of significant potential difference arising from the transition to IFRS." This is why the Board identified overhead and administration costs as an illustrative example of the types of changes in capitalization requirements that were being contemplated.

157. CND readily acknowledged in its pre-filed evidence on removal costs that this change to capitalization policy relating to the accounting of removal costs may not be material for all LDCs,[56] and thus may not have been singled out in the 2009 Board Report in the same way that the capitalization of indirect overhead and administration costs were. However, the evidence in this proceeding is that the Applicant's change in the capitalization of removal costs - $333,253 and $639,000 in 2012 and 2013 respectively – is material to CND (CND's materiality threshold is $125,000).[57]

158. Second, Staff references a Board letter entitled "Accounting for Overhead Costs Associated with Capital Work" and dated February 24, 2010. Staff rely on this letter to argue that "[i]n that letter, the Board stated that the scope of the capitalization was limited to the capitalization of overhead costs."[58]

[56] Exhibit K1.2 at pg. 6 at lines 1-5.
[57] Exhibit 1, Tab 7, Schedule 1, Page 1.
[58] Board Staff Submissions at Page 7.

159. This letter was issued a full two year before the July 17, 2012 Board letter which prompted CND to change its capitalization policy. In the February 24, 2010 letter, the Board provided licensed LDCs and rate-regulated natural gas utilities with additional clarification on accounting issues related to overhead costs associated with capital work. However, the fact that the Board provided clarification about one particular example of a change in capitalization policy does not, in-itself, have the effect of excluding other possible changes in capitalization policies. If one reads this letter from cover to cover, one is unable to identify where Staff is looking to suggest that the Board uses this letter to somehow limit the scope of allowable changes in capitalization policies.

160. In addition, the February 24, 2010 letter was issued as a result of a number of queries that were specifically related to overhead and administration costs due to a proposed draft IFRS standard on rate regulated accounting – which standard was subsequently withdrawn. Specifically (**emphasis added**):

> "The Board has received **a number of enquiries** regarding application of this portion of the Board Report. The enquiries have arisen given that the International Accounting Standards Board (IASB) has issued a **draft standard** on Accounting for Rate-Regulated Activities that states that a utility can include in the cost of capital works, costs beyond those permitted by the base IFRS standard (IAS 16 - Property, Plant & Equipment) if the regulator allows it and provides sufficient assurance of recoverability. The enquiries have been whether the Board would continue to allow capitalization of administration and other general overhead costs (currently explicitly prohibited by IAS 16, paragraph 191) for distributors currently doing so, if the standard were approved."[59]

161. In response, the Board states:

> "As stated in the Board Report at Issue 3.3, the Board is requiring full compliance with IFRS requirements (e.g., IAS 16) as applicable to non-regulated enterprises and only where the Board authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable."[60]

162. IAS 16 is not limited to the recognition of new assets in the distributor's books. IAS 16 includes sections on recognition (when to recognize an item of PP&E as an asset), measurement at recognition (includes the types of costs that qualify for recognition as an

[59] Board letter entitled "Accounting for Overhead Costs Associated with Capital Work" and dated February 24, 2010 at pg. 1.
[60] Ibid. at pg. 2.

asset), measurement after recognition (recognition at cost or fair value), depreciation (componentization of assets and depreciated separately), impairment (recognizing when an impairment has occurred and the asset value should be written down), derecognition (reporting of a gain or loss when an asset is derecognized as it has been disposed or no longer provides any future economic benefits) and disclosure (what information must be disclosed in the financial statements).

163. Staff's third point is that "[i]n Board staff's view, the removal cost issue in CND's Application are related to the de-recognition of the assets while capitalization policy is a distributor's determination of the threshold and criteria for the recognition of new assets in the distributor's books."[61]

164. Staff has failed to provide any concrete source to justify its very narrow interpretation of the term capitalization policy. There is no definition of capitalization policy to support Staff's view in the APH or in any of the other materials referenced by Staff in their submissions.

165. What is challenging from the Applicant's perspective is that Staff is proposing this new and narrow interpretation long after the fact, and without any reference to any financial or regulatory accounting standards to support its view.

166. In this context, the evidence on the record is clear: (1) the Applicant's capitalization policy previously provided that removal costs were included in the costs of building the new assets; and (2) consistent with the Board's July 17, 2012 letter CND's revised its capitalization policy effective January 1, 2012 which provides that, consistent with IAS 16, removal costs are to be expensed.[62]

167. Staff is effectively asking the Board to assume these facts away – which is entirely unfair to the Applicant which did in-fact change its capitalization policy effective January 1, 2012 and applied the Board's regulatory accounting policies appropriately in the circumstances.

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[61] Board Staff Submissions at pg. 8.
[62] Exhibit K1.2.

168. Fourth, Staff argue that "the Board did not require distributors to change the regulatory accounting treatment for de-recognition of group assets that was specified under the CGAAP-based Accounting Procedures Handbook."[63] In making this submission, Staff cite a specific sentence in the July 17, 2012 letter which states (emphasis added - in a different spot than Staff chose – to make a point):

> "**The Board will not require distributors to seek Board approval in order to make these accounting changes that otherwise would have been required as specified in the "CGAAP-based" APH** (dated July 2007), which is applicable and in force for these distributors still under CGAAP. **These accounting changes for adherence to Board requirements for MIFRS and their associated rate impacts will be reviewed as part of a distributor's next cost of service application.**"[64]

169. In making its submissions, Staff is necessarily assuming their own conclusion. There is nothing in the July 2012 letter which expressly states or even implies the narrow scope of regulatory accounting changes to capitalization policies as suggested by Staff. Reading the same letter, but acknowledging the fact that CND did undertake a change in its capitalization policy, leads to a very different approach.

170. What is important in this quote is that since CND continued under CGAAP but completed a change in its capitalization policies as permitted in the July 2012 letter, this accounting change would be reviewed as part of a distributor's next cost of service application. For CND, that is this Application. The letter indicates that the Board will be checking the change "for adherence to Board requirements for MIFRS." This is why CND provided detailed evidence in Exhibit K1.2 to demonstrate the adherence of its capitalization policy to IAS 16. It is simply not as cut and dry as proposed by Staff – that the requirement to adhere to MIFRS was somehow limited only to the capitalization of overhead and administration and depreciation expense.

171. Given this, the Applicant submits that it is important to consider the Board's July 2012 letter in the broader public policy context. Specifically:

    a. The Board determined in the 2009 Board Report that: "The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making

[63] Board Staff Submissions at pg. 8.
[64] Exhibit K1.2, Appendix A, Board letter dated July 17, 2012 at pg. 2.

and regulatory reporting purposes after the date of adoption of IFRS. The utility will file a copy of its capitalization policy, identifying any updates to the policy, as part of its first rate filing after IFRS adoption. Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified."[65]

b. In arriving at this approach, the Board acknowledges that "Data collected by Board staff indicated that the actual effect of the adoption of IFRS capitalization principles would vary greatly among utilities."[66] The Applicant agrees. For some utilities, changes to the capitalization of removal costs are likely minor. For others, like CND, they are material.

c. The Board also acknowledges that "The effort involved in keeping two sets of asset ledgers if IFRS capitalization rules were not adopted for regulatory purposes would increase costs to the utilities and their ratepayers."[67] Again, the Applicant agrees. Board Staff's recommendation would require CND to keep two separate asset ledgers, one for financial accounting purposes consistent with IFRS capitalization rules and another for regulatory purposes. This will increase costs for CND and its ratepayers.

d. The Board issued its July 17, 2012 letter indicating that "The Board will permit electricity distributors electing to remain on Canadian GAAP ("CGAAP") in 2012 to implement regulatory accounting changes for depreciation expense and capitalization policies effective on January 1, 2012."[68]

e. By this time, several distributors, including CND, had already completed sufficient detailed accounting work to adopt MIFRS accounting, specifically as it relates to PP&E.

f. The Board acknowledged (at pg. 2) that the key benefit that was expected to be derived from the Board's established accounting policies under the IFRS

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[65] 2009 Board Report at pg. 16-17.
[66] Ibid. at pg. 15.
[67] Ibid. at pg. 15.
[68] Exhibit K1.2, Appendix A, pg. 1.

accounting framework (Modified IFRS) was that the changes to the depreciation expense and capitalization policies would be applied uniformly and in the same timeframe by all distributors.

172. Fifth, Staff "notes that CND confirmed that the practice of including the removal costs in the cost of a new asset prior to 2012 was not in conformity with the CGAAP APH's requirement of charging the costs into Accumulated Amortization."[69]

173. Regardless of whether CND includes removal costs in the cost of a new asset or recorded that cost as part of accumulated amortization, the impact is the same – these costs were capitalized – they were not expensed. Staff appear to acknowledge this fact when noting that "the impact on net asset values at the time would have been the same under either approach."[70] In either case, a change is being made to the Applicant's capitalization policy in the true and actual meaning of the term. An amount that was previously capitalized under CND's capitalization policy is now being expensed.

174. Staff conclude by arguing that "the Board should not place any weight on the "capitalization" label when deciding this matter."[71]

175. CND disagrees.

176. Staff is asking the Board to take a very narrow interpretation of the term capitalization policy which is not supported by the Board's own Accounting Procedures Handbook – which does not define the term capitalization policy the way Staff has interpreted it – and is inconsistent with a straight forward interpretation of the Board's policy intent in creating account 1576.

177. CND's capitalization policy previously provided that removal costs were capitalized (as stated in Exhibit K1.2). CND's revised capitalization policy provides that effective January 1, 2012 removal costs are to be expensed.[72] This is clearly a change in capitalization policy. The significant elements of CND's capitalization policy are shown at Exhibit 2, Tab 2, Schedule 2, page 1 of 1.

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[69] Board Staff Submissions at pg. 8.
[70] Ibid.
[71] Board Staff Submissions at pg. 8.
[72] CND's capitalization policy is stated at Exhibit 2, Tab 2, Schedule 2 and is repeated again in Exhibit K1.2.

178. The sole reason CND revised its capitalization policies under CGAAP effective January 1, 2012 was explained by Ms. Sarah Hughes during the oral hearing:

> "As noted on page 1 of the exhibit, and as we described in our application, CND revised its capitalization policies under Canadian GAAP effective January 1st, 2012. CND undertook this change in 2012 in accordance with the Board's regulatory accounting requirements to align its capitalization policies by distributors in accordance with international financial reporting standards."[73]

179. This change in capitalization policy is described in the notes of CND's audited 2013 financial statements (filed in response to 7.1-SEC-40) at page 13 in respect of *significant accounting policies* in respect of subsection (g) for *capital assets*. The note states that "[c]osts incurred to remove an existing asset from service that are not directly attributable to site preparation for the construction of new assets are expensed." There is evidence that CND's change in the accounting treatment for removal costs was reviewed and confirmed by external auditors KPMG LLP (Exhibit K1.2, pg.2 at line 29), the same auditors that prepared an audit letter for the 2013 financial statements.

180. There is nothing in the Board's letter of July 17, 2012 or the 2009 Board Report that would narrow the definition of capitalization policies as is now being suggested by Staff. There is also no support in the APH or, as has been described above, any of the other materials referenced by Staff in submissions to support the narrow interpretation they are proposing.

181. CND, in its good faith interpretation of the instructions from the Board's letter, determined what capitalization policies were changed and dealt with all of the changes consistently with the instructions for account 1576 which indicates that distributors are authorized to record the financial differences arising from these accounting changes. Once again, at no time is the narrow scope to a change in capitalization policy as proposed by Staff mentioned.

G.2 Should CND include the test year removal costs as depreciation expense instead of including them in rate base?

182. Because Staff takes the position that the Board's July 17, 2012 letter does not apply to CND's change in capitalization policy as it relates to removal costs in respect of account

[73] Transcript Volume 1 dated April 29, 2014 at pg. 31 at line 27 to pg. 32 at line 5.

1576 – Staff places no weight at all on the Board's statement that "[t]he Board will permit electricity distributors electing to remain on Canadian GAAP ("CGAAP") in 2012 to implement regulatory accounting changes for depreciation expense and capitalization policies effective on January 1, 2012."[74]

183. Rather, Staff treat CND's change to its capitalization policy as it relates to the accounting treatment of removal costs as it would any other change to capitalization policy that an LDC might bring forward in the course of a cost-of-service application.

184. During "normal times" (i.e. in the absence of a transition to another accounting standard), LDCs are generally free to bring forward changes to their capitalization policies (for purposes of flowing these changes into rates going forward).

185. However, Staff's submissions are premised on the fact that we are not in normal times – that is we are in the midst of a transition to another accounting standard. In this context, Staff ask whether or not the Applicant should follow CGAAP or IFRS with respect to the regulatory accounting treatment of removal costs?

186. In this context, Staff conclude that "Because CND filed its CoS rate application on a CGAAP basis, Board staff submits that the regulatory accounting treatment for the treatment for the removal costs for CGAAP, as required under the CGAAP APH, should be followed. As such, the removal costs incurred by CND in 2014 should be charged to Accumulated Amortization for the relevant group assets."[75]

187. Put simply, Staff concludes that removal costs should be capitalized – not expensed as proposed by the Applicant. It is difficult to understand how Staff can suggest that the question at issue is not one that is properly the subject of a capitalization policy. From a regulatory accounting perspective, either the Board will permit the Applicant's capitalization of removal costs (as proposed by Staff) or it will require such costs to be expensed (as proposed by the Applicant). Either way, this question is the core focus of the Applicant's capitalization policy.

[74] Exhibit K1.2, Appendix A, pg. 1.
[75] Board Staff Submissions at pg. 9.

188. For the reasons already noted above in respect of historic removal costs, CND disagrees with Staff's interpretation of the July 17, 2012 letter. The July 17, 2012 letter does apply to CND's change in capitalization policy. The only reason CND pursued the change to its capitalization policy was because it was required under IFRS and was expressly permitted by the Board. The real question is whether the accounting change adheres to the Board requirements for MIFRS. CND set out in evidence the MIFRS requirements in Exhibit K1.2 and detailed how its change in capitalization policy is consistent with that accounting standard. KPMG has audited this accounting policy. No Party has suggested that CND's accounting treatment of removal costs is inconsistent with MIFRS.

189. Staff goes on to note that "there are other areas that will require changes when CND adopts of [sic] IFRS in 2015 but which CND did not address in this Application."[76] However, Staff fail to acknowledge that for the Applicant - post-retirement benefits and asset retirement obligations have not been identified as areas that are expected to result in material differences to CND's financial results and therefore CND did not bring forward these issues. By contrast, CND identified removal costs as they were material to the implementation of modified IFRS.

190. In conclusion:

   a. The Parties' concerns with the Applicant's accounting treatment of removal costs are premised on an assumption that a change in capitalization policy as contemplated in the Board's July 2012 letter is strictly limited to changes in the capitalization of overhead expenses.

   b. However, such a limited interpretation to the scope of a change of capitalization policy is not expressly stated anywhere in the July 2012 letter. In the 2009 Board Report, a change in overhead expenses is identified as an illustrative example of a change in capitalization policy and in response to enquiries about this particular illustrative example the Board did issue the February 24, 2010 letter. But an illustrative example and a response to frequently asked questions about that example does not have the effect of excluding other potential changes in

[76] Ibid.

capitalization policy that similarly fall within the scope of the Board's policy. Absent a clearly expressed intention to the contrary, an ordinary reading of the term capitalization policy should apply.

c. The evidence is clear that the change to the accounting treatment of removal costs is material to CND and that this change was implemented through a change in CND's capitalization policy.

d. The evidence is also clear that the only reason CND pursued the change to its capitalization policy was because it was the right thing to do. Specifically, CND identified that the change was required under IFRS and therefore CND implemented the change to its capitalization policy because it was permitted by the Board in the July 2012 letter.

e. Finally, the change proposed by the Applicant is entirely consistent with Board policy to require LDCs to move to IFRS. This is acknowledged by SEC in final argument noting that: "Cambridge plans to move to IFRS in 2015, and at that time will have to start charging these costs to operating expenses. It will also have to restate its previous year, 2014. The likely result will be that an amount will accumulate over the next five years, to be charged to ratepayers on their subsequent rebasing."[77]

f. In this context, it is also worth emphasizing that Kitchener-Wilmot Hydro Inc. began expensing dismantling costs (previously capitalized) for IFRS compliance in 2012,[78] and that this accounting treatment was ultimately accepted by parties and the Board.

H. CONCLUSIONS

191. For all of the foregoing reasons, CND submits that the Board should make an order for just and reasonable rates in the test year approving:

a. the Applicant's forecasted OM&A budget,

[77] SEC Final Argument at 5.2.2.
[78] EB-2013-0147 at Exhibit 9, Tab 1, Schedule 9, Page 5.

b. the Applicant’s proposed cost of long-term debt,

c. the Applicant’s forecasted other revenues derived from interest,

d. the Applicant’s proposed rate design for the GS>50kW class, and

e. the Applicant’s proposal to expense rather than capitalize removal costs during the test year and during the historic period since January 1, 2012 in a manner consistent with July 2012 letter.

192. None of the Parties have taken issue with CND’s request for an effective date for rates of May 1, 2014. CND adopts its submissions in its AIC in this support of this request. In particular, in this year of transition to the RRFE the Board has, to-date, granted a May 1, 2014 effective date to all other 2014 applicants including Haldimand, which filed on November 15, 2013, and Veridian, which filed October 31, 2013.

All of which is respectfully submitted this 26th day of May, 2014.

Original signed by John A.D. Vellone
John A.D. Vellone

TOR01: 5597479: v1

APPENDIX "A"
Comparison of actual vs. deemed debt-to-equity split for Ontario LDCs

Source: 2012 Year Book Data.

LDC	Actual Equity %	Deemed Equity %	Difference %	Actual Liabilities %	Deemed Liabilities %	Difference %
Cooperative Hydro Embrun Inc.	82%	40%	42%	18%	60%	-42%
Tillsonburg Hydro Inc.	73%	40%	33%	27%	60%	-33%
Chapleau Public Utilities Corporation	66%	40%	26%	34%	60%	-26%
Fort Frances Power Corporation	64%	40%	24%	36%	60%	-24%
Hydro 2000 Inc.	58%	40%	18%	42%	60%	-18%
Haldimand County Hydro Inc.	57%	40%	17%	43%	60%	-17%
Lakeland Power Distribution Ltd.	55%	40%	15%	45%	60%	-15%
Midland Power Utility Corporation	54%	40%	14%	46%	60%	-14%
Westario Power Inc.	53%	40%	13%	47%	60%	-13%
Wasaga Distribution Inc.	52%	40%	12%	48%	60%	-12%
Brant County Power Inc.	52%	40%	12%	48%	60%	-12%
West Coast Huron Energy Inc.	50%	40%	10%	50%	60%	-10%
Cambridge and North Dumfries Hydro Inc.	49%	40%	9%	51%	60%	-9%
Whitby Hydro Electric Corporation	49%	40%	9%	51%	60%	-9%
Kitchener-Wilmot Hydro Inc.	48%	40%	8%	52%	60%	-8%
Niagara-on-the-Lake Hydro Inc.	48%	40%	8%	52%	60%	-8%
Newmarket-Tay Power Distribution Ltd.	47%	40%	7%	53%	60%	-7%
Niagara Peninsula Energy Inc.	46%	40%	6%	54%	60%	-6%
Hydro Hawkesbury Inc.	45%	40%	5%	55%	60%	-5%
Norfolk Power Distribution Inc.	45%	40%	5%	55%	60%	-5%
Halton Hills Hydro Inc.	44%	40%	4%	56%	60%	-4%
Thunder Bay Hydro Electricity Distribution Inc.	44%	40%	4%	56%	60%	-4%
London Hydro Inc.	43%	40%	3%	57%	60%	-3%

LDC	Actual Equity %	Deemed Equity %	Difference %	Actual Liabilities %	Deemed Liabilities %	Difference %
Renfrew Hydro Inc.	43%	40%	3%	57%	60%	-3%
Centre Wellington Hydro Ltd.	43%	40%	3%	57%	60%	-3%
Kenora Hydro Electric Corporation Ltd.	42%	40%	2%	58%	60%	-2%
Hearst Power Distribution Company Limited	42%	40%	2%	58%	60%	-2%
Innisfil Hydro Distribution Systems Limited	42%	40%	2%	58%	60%	-2%
Burlington Hydro Inc.	41%	40%	1%	59%	60%	-1%
Milton Hydro Distribution Inc.	41%	40%	1%	59%	60%	-1%
Ottawa River Power Corporation	41%	40%	1%	59%	60%	-1%
North Bay Hydro Distribution Limited	41%	40%	1%	59%	60%	-1%
Orangeville Hydro Limited	40%	40%	0%	60%	60%	0%
Parry Sound Power Corporation	39%	40%	-1%	61%	60%	1%
Algoma Power Inc.	39%	40%	-1%	61%	60%	1%
Festival Hydro Inc.	38%	40%	-2%	62%	60%	2%
E.L.K. Energy Inc.	38%	40%	-2%	62%	60%	2%
Sioux Lookout Hydro Inc.	38%	40%	-2%	62%	60%	2%
Oshawa PUC Networks Inc.	38%	40%	-2%	62%	60%	2%
Waterloo North Hydro Inc.	38%	40%	-2%	62%	60%	2%
Rideau St. Lawrence Distribution Inc.	37%	40%	-3%	63%	60%	3%
Kingston Hydro Corporation	37%	40%	-3%	63%	60%	3%
Northern Ontario Wires Inc.	37%	40%	-3%	63%	60%	3%
Orillia Power Distribution Corporation	37%	40%	-3%	63%	60%	3%
Horizon Utilities Corporation	37%	40%	-3%	63%	60%	3%
EnWin Utilities Ltd.	37%	40%	-3%	63%	60%	3%
Lakefront Utilities Inc.	37%	40%	-3%	63%	60%	3%
Peterborough Distribution Incorporated	37%	40%	-3%	63%	60%	3%
Brantford Power Inc.	35%	40%	-5%	65%	60%	5%
Welland Hydro-Electric System Corp.	35%	40%	-5%	65%	60%	5%

LDC	Actual Equity %	Deemed Equity %	Difference %	Actual Liabilities %	Deemed Liabilities %	Difference %
St. Thomas Energy Inc.	35%	40%	-5%	65%	60%	5%
Grimsby Power Incorporated	35%	40%	-5%	65%	60%	5%
Guelph Hydro Electric Systems Inc.	34%	40%	-6%	66%	60%	6%
Erie Thames Powerlines Corporation	33%	40%	-7%	67%	60%	7%
Toronto Hydro-Electric System Limited	33%	40%	-7%	67%	60%	7%
Hydro Ottawa Limited	33%	40%	-7%	67%	60%	7%
Enersource Hydro Mississauga Inc.	33%	40%	-7%	67%	60%	7%
Wellington North Power Inc.	31%	40%	-9%	69%	60%	9%
Hydro One Brampton Networks Inc.	31%	40%	-9%	69%	60%	9%
Oakville Hydro Electricity Distribution Inc.	31%	40%	-9%	69%	60%	9%
Entegrus Powerlines Inc.	31%	40%	-9%	69%	60%	9%
Hydro One Networks Inc.	31%	40%	-9%	69%	60%	9%
Essex Powerlines Corporation	31%	40%	-9%	69%	60%	9%
PowerStream Inc.	31%	40%	-9%	69%	60%	9%
Bluewater Power Distribution Corporation	30%	40%	-10%	70%	60%	10%
Veridian Connections Inc.	30%	40%	-10%	70%	60%	10%
Woodstock Hydro Services Inc.	29%	40%	-11%	71%	60%	11%
Espanola Regional Hydro Distribution Corporation	28%	40%	-12%	72%	60%	12%
COLLUS PowerStream Corp.	26%	40%	-14%	74%	60%	14%
PUC Distribution Inc.	26%	40%	-14%	74%	60%	14%
Canadian Niagara Power Inc.	15%	40%	-25%	85%	60%	25%
Atikokan Hydro Inc.	13%	40%	-27%	87%	60%	27%
Greater Sudbury Hydro Inc.	9%	40%	-31%	91%	60%	31%