CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

April 9, 2015

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

RE: 2015 & 2016 TRANSMISSION REVENUE REQUIREMENT APPLICATION FOR CANADIAN NIAGARA POWER INC., ("CNPI") EB-2014-0204
REPLY SUBMISSION

Please find accompanying this letter, two (2) copies of CNPI's reply submission. Co-incidentally with the submission, an electronic copy of these responses have been filed via the Board's Regulatory Electronic Submission System.

If you have any questions in connection with the above matter, please do not hesitate to contact the undersigned at (905) 994-3634.

Yours truly,

Original Signed by:

Douglas Bradbury P.Eng,
Director Regulatory Affairs

Enclosure

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EB-2014-0204

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 Canadian Niagara Power Inc. for an order approving transmission revenue requirements to be effective January 1, 2015 and January 1, 2016.

Canadian Niagara Power Inc.

Reply Submission

April 9, 2015

INTRODUCTION

These are the reply submissions of CNPI Tx with respect to the submissions it has received from OEB Staff.

OEB Staff has provided its submissions as a series of discrete issues that it raises with respect to the application. CNPI Tx replies in kind, providing its submissions on each discrete issue raised by Board Staff on the assumption that if OEB Staff has not raised an issue there is no need to provide further submissions.

Where OEB Staff has made a specific request or suggestion that is different then what has been proposed by CNPI Tx, CNPI Tx has indicated whether:

a) it accepts the request or suggestion as an appropriate change to what it has proposed, or

b) it opposes the request or suggestion as being an appropriate change to what it has proposed and provides submissions as to why CNPI Tx believes the request or suggestion is inappropriate, or provides an alternative to the request or suggestion in order to meet the concerns raised by OEB Staff.

Where OEB Staff has commented on an issue but indicates that it agrees with CNPI Tx on the ultimate outcome CNPI Tx has only provided reply comments as necessary. For example, although OEB Staff provides extensive comments with the respect to the International Power Line, ultimately OEB Staff endorses the project, only suggesting that the application be changed with respect to its forecast in service date. Accordingly CNPI Tx only provides reply submissions with respect to the aspect of OEB Staff's submissions that deal with the proposed in service date of the project.

UPDATED REVENUE REQUIREMENT

OEB Staff's submissions include a request that CNPI Tx provide a detailed analysis of the updated "operating costs" included implicitly in the updated Revenue Requirements. Included as Appendix A to this submission are Tables for both 2015 and 2016 which reflect the original application and the updated application after a) adjustments that CNPI Tx had agreed to make during the hearing phase, and b) adjustments that CNPI Tx has agreed to make during the argument phase, for all aspects of the Revenue Requirement. Specific to operating costs, the total changes are as follows:

CHANGES IN OPERATING COSTS CLAIMED IN THE APPLICATION

	2015	**2016**
Original Application	$ 2,968,381	$ 3,072,214
Updated Application	$ 2,934,963	$ 3,096,645

Accordingly Appendix A to this submission represents the revenue requirements for 2015 and 2016 should the Board accept CNPI Tx's submissions with respect to its application, including those adjustments that OEB Staff has requested that CNPI Tx has agreed to make.

CAPITAL EXPENDITURES AND RATE BASE

International Power Line

OEB Staff agrees with the justification, reasonableness, and rate treatment of the proposed rebuild of the International Power Line (the "IPL"), including the quantification of the projected costs.[1]OEB Staff's only issue with respect to the IPL project is the proposed in service date of Q4 2015, given that CNPI Tx does not propose to start ordering materials for the project until the Board provides approval for the IPL spending and given the project timelines in the evidence.[2]

CNPI Tx respectfully maintains, as it has in the evidence and during the course of the oral hearing, that its forecast in service date of December 31, 2015 for the IPL remains reasonable, including consideration of the timing of the completion

[1]OEB Staff Submission pages 4-6.
[2]OEB Staff Submission pages 6-8.

of this proceeding. However, in order to respond to OEB Staff's concerns, CNPI Tx would respectfully submit that the Board could require CNPI Tx to establish a variance account to track the revenue requirement impacts should the IPL not be placed in service prior to December 31, 2015. In the event the IPL is not in service prior to December 31, 2015, the account would record:

1. the full revenue requirement impact of the IPL spending as included in the 2015 revenue requirement for disposition at a later time, and
2. the reduction in the 2016 revenue requirement impact of the IPL spending as a result of the half year rule assumption being applied to that spending in 2016 rather than 2015.

CNPI continues to believe that the IPL will be in service in 2015. However, in the event it is not, CNPI's proposal will ensure that ratepayers will be fully protected.

CUSTOMER DELIVERY POINT PERFORMANCE STANDARDS

CNPI Tx has reviewed the submissions of OEB Staff with respect to changes it should consider making to its Customer Delivery Point Performance Standards[3] and has no objections to incorporating those changes. Attached as Appendix B to this submission is an updated Customer Delivery Point Performance Standards document for CNPI Tx that incorporates OEB Staff's suggestions.

OPERATING MAINTENANCE AND ADMINISTRATIVE EXPENSES

Removal of 25 hertz Cycle Transmission Line

[3]OEB Staff Submission pages 8-9.

OEB Staff proposes in its submissions that CNPI Tx maintain the pace of the tower removal associated with the defunct line at 15 towers per year, rather than the proposed 30 towers per year commencing in 2015. OEB Staff makes this proposal on the basis that that "OEB staff questions the urgency that requires a doubling of the tower removal . . .".[4]

On the basis of that submission OEB Staff suggests a reduction in the OM&A expenses proposed for the removal in 2015 and 2016 of $58,000 to reflect the actual recent pace of the program.

In CNPI Tx's view it simply does not make sense, from either safety or an economic perspective, to reduce the pace of the removal of these tower from the proposed 30 towers per year.

From a safety perspective CNPI has explained the observations that lead to the conclusion that the pace of the tower removal should be accelerated in order to mitigate against the risk of an incident.[5] At a pace of 30 towers of year CNPI Tx projects the removal of all towers by 2018.[6] Reducing the pace of the removal to 15 towers per year means that the last towers will not be removed until approximately 2022, an additional 4 years within which the towers, unused and unmaintained, will be subject to further deterioration and an increasing risk of incident. CNPI Tx respectfully submits that it does not want to be in the position of, having identified the risk with respect to the towers and having proposed a schedule for their safe removal, being constrained in addressing the issue in a timely fashion.

[4] OEB Staff Submission pages 10-12.
[5] EB-2014-0204 transcript (oral hearing) pages 89-91.
[6] Exhibit 4 Tab 3 Schedule 1 page 2.

From an economic perspective there is little reason, CNPI Tx would respectfully suggest, to slow the pace of the removal and incur the additional safety risks associated with towers remaining for as long as 4 more years then CNPI Tx has proposed. Not only are the incremental costs of removing an additional 15 towers per year modest on a stand-alone basis, constituting only $58,000 per year in OM&A expense(which expense concludes in 2018 when all the towers are removed), but the cost of removing an additional 15 towers per year is only 50% more than the cost of removing the initial 15 towers per year, an economy of scale that reduces the per tower costs from approximately $6,666 per tower to $5,000 per tower. Put another way, the total cost to replace all remaining towers at a rate of 15 towers per year is approximately $168,000 more expensive than the cost of replacing the same number of towers at a rate of 30 towers per year.

In summary, in light of the identified safety concerns associated with leaving towers unaddressed for as many as an additional 4 years, and in light of the modest cost of the incremental costs associated with the doubling of the pace of the program and the economies of a 30 tower program as opposed to a 15 tower program, CNPI Tx respectfully submits that it should be permitted to implement the program as applied for with the associated costs included in the revenue requirement.

One Time Regulatory Expenses

OEB Staff has suggested that CNPI Tx's forecast of One Time Regulatory Expenses be updated to reflect that manner in which this application has proceeded in reality, recognizing, for example, that there were no intervenor costs and consequentially no settlement conference, concluding ultimately that the forecast annual amount included in the 2015 and 2016 revenue requirements should be reduced by $16,849.[7]

CNPI Tx respectfully submits that in the normal course it is not the practice of the Board to essentially update to actuals the forecast regulatory costs for an application at the argument stage in order that the forecast match more closely the actual path of the proceeding. It is CNPI Tx's understanding, generally speaking, that upon making a reasonable forecast and including that forecast in the application the applicant is normally at risk with respect to the progress of the proceeding, absent unusual circumstances. CNPI Tx would also note that the proposed annual reduction of $16,849 is below CNPI Tx's materiality threshold.

However, in the context of this proceeding CNPI Tx does not oppose OEB Staff's request, and has reflected the proposed reduction in its updated RRWFs included as Appendix A to this submission.

Salaries and Wages

OEB Staff has proposed that CNPI Tx should be limited to forecast wage increases based on an assumed rate of inflation of 2% for both union and non-union compensation, with a resulting decrease in OM&A costs of $10,000 and $20,000 in 2015 and 2016 respectively based on the response to 4-Staff-37.[8]

CNPI Tx respectfully notes that, as noted in 4-Staff-37, compensation for union labour for CNPI Tx is governed by a collective agreement for all of 2015 and part of 2016; based on that collective agreement wage increases for union labour are forecast at 3.1% for 2015. As there is no suggestion that CNPI Tx was imprudent

[7] OEB Staff Submission page 12.
[8] OEB Staff Submission page 12.

when negotiating the governing collective agreements. CNPI Tx submits that the forecast for at least the union employees for 2015 and part of 2016 are reasonable at 3.1%, and that correspondingly the forecast increases for non-union employees at a similar level is reasonable.

Accordingly even if one were to reduce the non-union compensation increase to 2% the resulting deductions from the forecast would be less than $10,000 for 2015 and less then $20,000 in 2016, both figures well below the materiality threshold for CNPI Tx and both depending on CNPI Tx being able to negotiate wage increases for non union labour at rates significantly less then what is included in the prevailing collective agreements.

CNPI Tx would also suggest that the numbers proposed by OEB Staff are further inflated for 2015 in particular, as the response in question was prepared prior to CNPI Tx deducting $40,000 from the 2015 Revenue Requirement to reflect no compensation being paid at all for several temporarily vacant positions.[9]

For these reasons CNPI Tx respectfully submits that the Board should not accept OEB Staff's proposal for a reduction to the OM&A for 2015 and 2016.

CAPITAL STRUCTURE AND COST OF CAPITAL

OEB Staff notes that CNPI Tx's proposed return on equity, proposed debt rate associated with the affiliated promissory note (the only debt instrument issued by CNPI Tx) and the proposed short term debt rate are all based on the Board's approved cost of capital parameters as issued by the Board on November 25, 2013 for the 2014 rate year and that CNPI Tx indicated in its application that it

[9] CNPI Tx Argument in Chief page 2 describes this adjustment.

would update those capital cost parameters to reflect the OEB's cost of capital parameters current at the time of the OEB's decision.

OEB Staff's submissions include a request that CNPI Tx identify when it will file updated capital cost parameters which reflect the capital cost parameters issued by the Board on November 20, 2014.

CNPI Tx can, through this submission, confirm that the updated capital cost parameters issued by the Board on November 20, 2014 are the most current OEB approved parameters applicable to CNPI Tx, and as such CNPI Tx will use those numbers when calculating the final Revenue Requirements for 2015 and 2016. Those numbers, as compared to the numbers used as placeholders in the application, are summarized in the following table:

COST OF CAPITAL PARAMETERS

	Board Approved as of November 23 2013 and included in Original Application	**Board Approved as of November 20, 2014**
Return on Equity	9.36%	9.30%
Debt Rate on Affiliated Promissory Note	6.08%	6.03%
Short Term Debt Rate	2.11%	2.16%

Attached as Appendix C to this submission is a detailed calculation of the effect of the updated rates on the applied for Revenue Requirements, and CNPI Tx notes that the updated figures are reflected in Appendix A.

REGULATORY ACCOUNTING

Effective Date of Changes in Accounting Policy

OEB Staff has raised the issue with respect to the applicability of the Board's requirement that distributors implement certain accounting policy changes effective January 1, 2013 to CNPI Tx and other transmitters, including the requirement that the revenue requirement implications of those changes be tracked for disposition in account 1576.[10]

As noted by OEB Staff CNPI Tx is seeking Board approval through this application to make the applicable policy changes and reflect the revenue requirement impacts starting January 1, 2015. Accordingly the issue is not whether CNPI Tx should make the changes at all, as it has already proposed to do so.[11]

Rather, OEB Staff points out that Great Lakes Power Transmission LP ("GLP") and Hydro One Transmission ("HOT") both updated their accounting policies in years prior to 2015, and on that basis invites the Board to consider whether it may require CNPI Tx to reflect an effective date of January 1, 2013 for accounting policy changes.[12]CNPI Tx notes that OEB Staff does not ultimately suggest definitively that CNPI Tx should be required to reflect an effective date of January 1, 2013; OEB Staff only raise the issue for consideration.

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[10]OEB Submission pages 13-16.
[11]OEB Submission page 13.
[12]OEB Submission page 15. CNPI Tx notes that while the discussion is usually described in terms of multiple accounting policy changes, the only change that is and would have been applicable to CNPI Tx relates to changes in useful lives of assets for the purpose of calculating depreciation expense.

CNPI Tx respectfully submits that requiring CNPI Tx to reflect an accounting policy change in January 2013 and then to ostensibly track the impact of that change in Account 1576 would, in the circumstances of CNPI Tx, constitute impermissible retroactive rate making.

In order to implement an accounting policy change, including a change in the assumed useful lives of assets for the purpose of calculating the applicable depreciation expense, CNPI Tx, like any other regulated entity, requires permission of the Board to do so. This permission is required because such changes can alter the revenue requirement that underpins the approved rates charged by the regulated entity, such that in order to implement the change fairly as between rate payers and the regulated entity the Board has to consider how the change should affect rates.

In the case of distributors regulated by the OEB, the Board, by letter dated July 17, 2012, specifically required distributors to make two accounting policy changes (to the extent those changes were applicable to the individual distributor) effective, at the latest, January 1, 2013. CNPI Tx attaches a copy of that letter as Appendix D and notes that it is specifically applicable to distributors only.

The Board further specifically permitted distributors to track the revenue requirement implications of those changes in account 1576 in order that the effects of the policy changes, to the extent those effects impacted the revenue requirements that underpinned a distributor's approved rates, would be captured as a debit from or credit to ratepayers without the need for a rate application. In the absence of permission to use account 1576 in this way the net result of the policy changes, whether a debit from or credit to ratepayers, could not be collected from or become payable to ratepayers, as such collection or payment would have constituted a retroactive rate change.

In the case of transmitters, including GLP, HOT and CNPI Tx, the Board did not issue a general mandate requiring two accounting policy changes effective January 1, 2013, nor did the Board issue general permission for transmitters to record the effects of such changes in Account 1576.

In the case of HOT, as summarized by OEB Staff, changes in accounting policies, including specifically changes in useful lives, were routinely reviewed and updated for the purposed of setting rates from approximately 2007 to 2016.[13] However in every instance the updates were implemented in the context of a rate application within which the proposed accounting policy changes were reviewed and specifically approved by the Board; HOT never relied on nor could it rely on a policy direction to distributors in order to unilaterally change its accounting policies and track the effects in a deferral account.

Similarly OEB Staff notes that GLP ostensibly used account 1575 to record differences associated with the transition to IFRS, including difference in depreciation expense caused by changes in useful lives.[14] However, again, the implementation of such changes and the creation and use of such an account by GLP were authorized by the Board in the context of rate application decisions that explicitly considered those changes and the request for an account to track the impacts; GLP did not and could not make such changes and capture the impacts of those changes without having applied for Board approval. It is of note, for example, that while OEB Staff refers to the GLP rate application for the years 2013 and 2014 (EB-2012-0300) and GLP's adoption of IFRS effective January 1, 2013 coincident with the rate application seeking approval of that change, GLP actually established the deferral account (later named Account 1575) to track the

[13] OEB Staff Submission page 15.
[14] OEB Staff Submission page 15.

effects of the transition to IFRS in its previous rate application (EB-2010-0291) well in advance of the actual transition and any impacts.

As the Board is aware CNPI Tx has not been before the Board with a rate application for adjustments to rates for a rate year subsequent to 2002. Accordingly the Board has not specifically reviewed CNPI Tx's accounting policies or established any deferral accounts to track changes in policies specific to CNPI Tx, nor did the Board, on its own initiative and outside a utility specific rate application, mandate that CNPI Tx or any other regulated transmitter make any accounting policy changes and permit CNPI Tx or any other regulated transmitter to establish an account to track the impact of those changes in a deferral account so as to avoid the issue of retroactivity.

OEB Staff refers to the Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment (EB-2008-0408), June 13, 2011, which suggests that, with respect to IFRS issues, ". . . the Board will have regard to the policy and rationale for the policy in this Addendum when considering similar issues for other regulated entities." Similarly OEB Staff observes that CNPI Tx looks to the OEB's policies related to distributors to justify its capitalization and depreciation policy proposals for the subject application.[15]

To be clear, CNPI Tx does not disagree that the accounting policy issues dealt with by the Board explicitly with respect to distributors through its distributor specific mandates will likely, in principle, apply similarly if not identically to non-distributors; with respect that is not the issue in this instance. What is at issue is the lack of a Board approved mandate issued to transmitters to implement accounting policy changes outside of transmitter specific applications,

[15]Board Staff Submission page 16.

accompanied by the lack of a Board approved mechanism extended to transmitters to track the impacts of such changes outside transmitter specific applications.

HOT applied, within the context of its serial rate applications with respect to its 2007 to 2016 rate years, for approval of accounting policy changes that reflected the changes ultimately required by the Board from all distributors effective January 1, 2013; similarly GLP applied for approval of accounting policy changes within the context of its several rate applications with respect to its 2011 to 2014 rate years. By contrast, CNPI Tx was not before the Board during that period, so did not have the authority to change its accounting policy or track the impacts of accounting policy changes outside of a CNPI Tx specific application, an application which, until the subject application dealing with accounting policy and impacts related to the January 1, 2015 rate year and beyond (with an accompanying direction from the Board declaring CNPI's revenue requirement interim effective January 1, 2015 in order to ensure no issue of retroactivity is associated with the timing of the Board's decision in this case) was filed.

CNPI Tx would note, as was noted by OEB Staff, that the effect of implementing the accounting change with respect to useful lives on January 1, 2015 in the context of a rate application rather than January 1, 2013 is that CNPI Tx's rate base for the purposes of calculating revenue requirement for 2015 and beyond is lower than it would otherwise be, based on the difference between the updated depreciation rates and the depreciation rates that subsisted between January 1, 2013 and the present. More specifically, as summarized by OEB Staff, although requiring an effective date of January 1, 2013 would create a balance of approximately $465,000 in account 1576 to the credit of ratepayers, over the remaining updated useful lives of the affected facilities this credit would be offset by a higher rate base in future years.[16] There has accordingly not been, CNPI Tx respectfully submits, some sort of windfall on its part as a result of the different implementation dates for this policy change that the Board should be concerned about.

Accordingly, in summary, CNPI Tx respectfully submits that it would be inappropriate for the Board to reflect an effective date for the noted accounting policy change of January 1, 2013, given that no authorization to make such a change or record the impacts of such a change was granted to CNPI Tx contemporaneously to that date such that requiring it now would amount to impermissible retroactive rate making. Ratepayers are held whole, in that to the extent they may not benefit from a credit as a result of implementing the change 2 years earlier, they do benefit from an offsetting reduction in rate base going forward.

Lastly, OEB Staff notes that CNPI Tx is allocated a small portion of capital related costs from CNPI Distribution, and that CNPI Distribution, having made changes to its depreciation policies effective January 1, 2013 in accordance with the Board's directions, would have allocated the effects of the change to CNPI Tx such that a small portion of CNPI Tx's assets (although an allocation of distribution owned assets) reflect the change in policy effective January, 1 2013.[17]

CNPI Tx notes that a review of the allocations referred to by Board Staff reveals the following:

[16] OEB Staff Submission page 14.
[17] OEB Staff Submission page 15.

a) there are only 10 asset classes that CNPI Distribution allocates a portion of to CNPI Tx,[18]

b) of the 10 assets classes that are allocated to CNPI Tx, only two of those classes, GA Communication Equipment, which moved from a 10 year useful life to a 20 year useful life, and GA System Supervisory Equipment, which moved from a 20 year useful life to a 10 year useful life, were affected by the updated Useful Lives implemented by CNPI Distribution,[19]

c) by way of illustration the total amount of depreciation expense allocated to CNPI Tx in 2012 for these two classes of assets totalled $7,894.[20]

Accordingly, given the relatively small amount of the depreciation expense related to these two categories in total, and given that the amount that would have been recorded with respect to the increase in useful life for Communication Equipment would have been offset by the equal decrease in useful life for System Supervisory Equipment, CNPI Tx respectfully submits that the amount that would have been tracked in respect of these classes, were CNPI Tx been authorized to track the effect of the changes through the use of a deferral account, would have been immaterial and, quite possibly, would have been a debit to be collected from ratepayers.

Account 1592 PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits

[18] 4-Staff-32 page 4 shows a table of all the classes that CNPI Distribution allocates to CNPI Tx.

[19] EB-2012-0112 E11 T1 S3 Appendix B page 7.

[20] 4-Staff-32 The 2012 depreciation expenses for these two classes can be calculated by deducting the Allocation of the Accumulated Depreciation for each class in 2011 from the Allocation of the Accumulated Depreciation for each class in 2012.

OEB Staff raises the issue of the applicability of Account 1592 with respect to the tracking of HST/OVAT Input tax credits to the credit of rate payers from 2010 to 2014 to CNPI Tx, but does not ultimately take issue with the fact that no such tracking took place on the basis of the immateriality of the amounts that would have been tracked in such an account had it been established. As estimated by CNPI Tx in Exhibit J1.1 the total amount that would have been tracked in such an account is approximately $16,000.00, well below both the annual and cumulative materiality threshold for CNPI Tx over that period. Accordingly CNPI Tx does not have any responding submissions to make on this issue.

PROJECT FORTRAN

OEB Staff submits that the Board should deny CNPI Tx's request for recovery of amounts related to Project Fortran for two reasons, first, that the OEB has already denied the request in EB-2010-0159, and second, that allowing the recovery would amount to retroactive ratemaking. CNPI respectfully makes the following submissions in reply to these two assertions.

The request for relief related to Project Fortran has not been previously denied by the Board

As OEB Staff notes, CNPI Tx commenced an application to create a deferral account to record the Project Fortran Costs for future disposition, and asserts that the decision in that case is determinative of any request for relief for the recovery of Project Fortran costs by CNPI Tx.

CNPI Tx respectfully submits that OEB Staff has interpreted the decision of the Board in EB-2010-0159 too broadly. CNPI Tx attaches the full text of that decision as Appendix E to this proceeding for ease of reference for the Board Panel.

In that decision the Board dealt with and disposed of a single issue; the appropriateness of establishing a deferral account to track Project Fortran costs.

As set out at page 5 of the decision:

> In the Board's view, the main issue in this case is whether CNPI's proposal is appropriate and reasonable in terms of the timing of the spending in relation to the approval sought to establish the proposed deferral account. Regulatory policy, practices, and tenets of cost of service rate making that make up the regulatory compact must be considered in this case.

And at page 7:

> Criteria for Establishing a Deferral Account
>
> There were substantial interrogatories and submissions from Energy Probe and CNPI on whether or not the four criteria mentioned above apply to this case. In the Board's view, deferral accounts are for the current period or future costs. This includes Z-factor costs which are recorded in a deferral account (1572 - Extraordinary Event Costs) provided that they ultimately meet the criteria mentioned above. The Board accepts CNPI's position that the Preliminary Costs are not Z-factor costs. In addition, there is no other provision for establishing a deferral account for expenditures that have already been made in relation to costs incurred in a prior year.

In CNPI Tx's respectful submission, these two sections of the decision in EB-2010-0159 describe the single issue considered and decided upon by the Board in that proceeding; whether or not in the circumstances of the case CNPI Tx met the criteria for establishing a deferral account to track the costs outside of its normal accounting of costs. The Board did not consider, at any point, the prudence of the costs, nor did the Board make a decision with respect to the ability of CNPI Tx to bring the costs forward for disposition in its next cost of service within the context of its existing accounting procedures.

CNPI Tx submitted in that proceeding, and the Board specifically noted in its decision, that CNPI Tx had only brought the request for a deferral account because it was not certain about the appropriateness of keeping those preliminary costs in a construction work in progress account, and that CNPI Tx did not object to leaving the costs in a construction work in progress account for disposition at CNPI's next transmission cost of service rate application.[21]

In CNPI Tx's respectful submission the effect of the Board's decision in EB-2010-0159 was to deny deferral account treatment for Project Fortran costs, with the consequence that CNPI Tx became unable to effect recovery of those costs outside of a cost of service application. The Board, having not decided with respect to the prudence of those cost, and having not decided with respect to the recoverability of those cost through the use of the existing accounts available to CNPI Tx, left it open to CNPI Tx to retain those costs in existing accounts and seek recovery as part of this application.

The request for relief related to Project Fortran costs would not constitute retroactive rate making

As was noted in the Decision in EB-2010-0159, the Project Fortran Costs were, in the absence of the establishment of a deferral account that would have

[21]EB-2010-0159 Decision dated August 18, 2010, page 4.

allowed recovery of those costs outside a cost of service proceeding, tracked in an existing account as construction work in progress, as they were costs disbursed in contemplation of a capital project such that, if and when the project became completed, the costs would in the normal course be closed to rate base.

Regulated utilities routinely track such costs as construction work in progress, and in doing so are able to track costs incurred over the course of several years without having to expense them; in this way costs incurred in one year are routinely brought forward for disposition in later years.

Accordingly CNPI Tx does not agree with OEB staff when it asserts that:

> Although CNPI Tx booked these amounts in their own construction work in progress account, this is not an OEB-approved deferral or variance account. To allow CNPI Tx to recover these amounts starting in 2015 would be a clear case of retroactive ratemaking.[22]

With respect, if it were the case that booking amounts as construction work in progress did not have the effect of bringing expenses forward for disposition outside the year they were originally incurred, then all utilities with multi year capital projects would be unable to recover costs in rates related to expenditures in years prior to the year the project was put into service and considered by the Board for inclusion in rate base.

Accordingly the specific issue in this case is that although the costs were incurred as early as 2003 and brought forward as construction work in progress costs until 2009, being as they were costs associated with a proposed capital

[22] OEB Submission page 18.

project, the capital project they were related to did not proceed once the Board denied the leave to construct in EB-2009-0283.[23]

In CNPI Tx's respectful submission the Project Fortran costs, as detailed in 4-Staff-36, are properly brought forward through the operation of existing Account 1510 B, which provides as follows:

> 1510 Preliminary Survey and Investigation Charges
>
> B. <u>This account shall also include costs of studies and analyses mandated by the Board</u> related to plant in service. If construction results from such studies, this account shall be credited and the appropriate utility plant account charged with an equitable portion of such study costs directly attributable to new construction. The portion of such study costs not attributable to new construction <u>or the entire cost if construction does not result shall be charged to Account 1505, Unrecovered Plant and Regulatory Study Costs</u>, or the appropriate operating expense account. The costs of such studies relative to plant under construction shall be included directly in Account 2055, Construction Work in Progress Electric.
>
> 1505 Unrecovered Plant and Regulatory Study Costs
>
> A. This account shall include: (1) Non-recurring costs of studies and analyses mandated by the Board related to plants in service, transferred from Account 1510, Preliminary Survey and Investigation Charges, and not resulting in construction; and (2) when authorized by the Board, significant unrecovered costs of plant facilities where

[23] EB-2009-0283 Decision page 2.

> construction has been cancelled or that have been prematurely retired.
>
> B. This account shall be credited and Account 5730, Amortization of Unrecovered Plant and Regulatory Study Costs, shall be debited over the period specified by the Board.[24](Emphasis added)

As set out in 4-Staff-36:

> Each phase of the development of the Fortran proposal have been detailed in Exhibit 10 Tab 1 Schedule 1of the Application. The steps taken by CNPI Tx were regulatory requirements (i.e., IESO System Impact Assessment, Hydro One Customer Impact Assessment and NYISO System Reliability and Impact Assessments) to advance the section 92 application. These investments were not discretionary investments; for without them being completed, the application could not be brought to the Board. Therefore they would be considered mandatory expenditures.

Accordingly, CNPI Tx respectfully submits, if the Board agrees that these costs were mandated by the Board, as they were prerequisites for consideration of the proposed project at the Leave to Construct proceeding, then these costs were to be recorded in account 1510 and, when the project did not result in construction, moved to 1505 to be disposed of as directed by the Board.

Assuming the Board agrees that the decision in EB-2010-0159 was not determinative of the issue as to whether these costs could be brought forward outside the use of a specially created deferral account, and assuming that the Board agrees that the nature of these costs were such that they were properly

[24]4-Staff-36 pages 1-2.

recorded in account 1510 and, when the project did not result in construction, moved to 1505 to await disposition by the Board, CNPI Tx respectfully submits that the Board panel in this proceeding is seized with determining whether all, some or none of the costs incurred were prudent, and to the extent the Board determines that all or some of the costs were prudent provide for their disposition to the credit of CNPI Tx.

OEB Staff did not provide submissions either supporting or critiquing CNPI Tx's assertion that the Project Fortran costs were prudently incurred; accordingly CNPI Tx simply repeats and relies on the evidence and its argument in chief with respect to the prudence of these costs.

The Project Fortran costs, amounting to $1,221,281, while not necessarily a large item from the perspective of ratepayers when one considers that such costs are recovered through Uniform Transmission Rates, constitute a very large expenditure for CNPI Tx, amounting to approximately 25% of CNPI's total revenue requirement in a single year; accordingly CNPI Tx has proposed a 10 year amortization period to reflect a modest recovery of the expense over approximately the same number of years over which the cost was incurred.

CALCULATION OF UNIFORM TRANSMISSION RATES

OEB Staff notes that CNPI Tx is requesting that its updated revenue requirements, for the purpose of collection through Uniform Transmission Rates, be effective January 1, 2015 and January 1st 2016 respectively, and that on December 18, 2014 the existing CNPI Tx revenue requirement was declared interim by the Board effective January 1, 2015.

Accordingly OEB Staff has requested that the Board establish a deferral account to record the foregone revenue resulting from the difference between the proposed January 1, 2015 effective date and the implementation date of the new revenue requirement pursuant to the Board's decision in this application.

CNPI Tx has included a draft accounting order for such an account as requested by OEB Staff.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 9th Day of APRIL, 2015

APPENDIX A

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CNPI Transmission

2015 Components of Revenue Requirement

Particulars	Requested 2015	Response to OEB Staff	Change	%
Rate Base	$ 21,599,433	$ 20,790,755	$ (808,678)	-3.7%
Cost of Capital	7.23%	7.18%		
Return on Rate Base	$ 1,562,330	$ 1,493,442	$ (68,888)	-4.4%
OM&A Expenses (Note 1)	$ 1,877,416	$ 1,820,567	$ (56,849)	-3.0%
Amortization/Depreciation	$ 820,993	$ 813,687	$ (7,306)	-0.9%
Property Taxes	$ 135,300	$ 158,300	$ 23,000	17.0%
Capital Taxes	$ -		$ -	
Income Taxes (Grossed up)	$ 134,672	$ 142,409	$ 7,737	5.7%
2015 Revenue Requirement	$ 4,530,710	$ 4,428,405	$ (102,305)	-2.3%

Note 1	$1,877,416
	(40,000.00)
	(16,849.00)
	$1,820,567

2016 Components of Revenue Requirement

Particulars	Requested 2016	Response to OEB Staff	Change	%
Rate Base	$ 24,136,516	$ 24,211,326	$ 74,810	0.3%
Cost of Capital	7.23%	7.18%		
Return on Rate Base	$ 1,745,842	$ 1,739,148	$ (6,694)	-0.4%
OM&A Expenses	$ 1,919,060	$ 1,902,211	$ (16,849)	-0.9%
Amortization/Depreciation	$ 885,209	$ 902,276	$ 17,067	1.9%
Property Taxes	$ 138,006	$ 161,006	$ 23,000	16.7%
Capital Taxes	$ -		$ -	
Income Taxes (Grossed up)	$ 129,939	$ 131,152	$ 1,213	0.9%
2015 Revenue Requirement	$ 4,818,056	$ 4,835,793	$ 17,737	0.4%

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APPENDIX B

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CANADIAN NIAGARA POWER INC.
TRANSMISSION

CUSTOMER DELIVERY POINT
PERFORMANCE STANDARDS

Revised April 2015

1 Introduction

Canadian Niagara Power Inc. ("CNPI") Tx has prepared this Customer Delivery Point Performance Standard ("CDPPS") in accordance with the Transmission System Code, Section 4.5 Performance Standards; specifically Section 4.5.1 reproduced below:

A transmitter shall develop performance standards that apply at the customer delivery point level and that:

(a) reflect typical transmission system configurations that take into account the historical development of the transmitter's transmission system at the customer delivery point level;

(b) reflect historical performance at the customer delivery point level;

(c) are, where applicable, consistent with the comparable performance standards applicable to all delivery points throughout the transmitter's transmission system;

(d) establish acceptable bands of performance at the customer delivery point level for transmission system configurations, geographic area, load, and capacity levels;

(e) establish appropriate triggering events to be used to initiate technical and economic evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, as well as the circumstances in which any such triggering event will not require the initiation of a technical or economic evaluation;

(f) establish the steps to be taken based on the results of any evaluation that has been so triggered, as well as the circumstances in which such steps need not be taken; and

(g) establish any circumstances in which the performance standards will not apply.

2 Aspects of CNPI Tx's Transmission System

Description of CNPI Tx's transmission system Customer Delivery Points:

I. The CNPI transmission system has only two Customer Delivery Points (CDPs).

II. The Customer Delivery Points are owned and operated by CNPI's transmission business unit ("CNPI Tx").

III. Both Customer Delivery Points are supplied by CNPI Tx's radial 115kV transmission system.

IV. CNPI Tx's 115 kV transmission system is an extension to the Hydro One Networks Inc.'s ("HONI") 115 kV transmission system with the common point of coupling at HONI's transmission station in Niagara Falls, Canada.

V. Both Customer Delivery Points serve the same customer: the portion of CNPI's distribution business unit serving the Fort Erie service territory.

These aspects of CNPI Tx's transmission system influence the CDPPS; specifically:

I. CNPI Tx's transmission system is a radial extension of HONI's transmission system and therefore its performance can be highly dependent upon the performance of HONI's transmission system. For this reason, the performance targets will be set both independently of HONI's system, and also taking into account the total performance of the transmission systems of CNPI Tx and HONI with respect to CNPI's two CDP.

II. With only two Customer Delivery Points there is very small sample to perform statistical analysis on historical results. Therefore, performance targets based purely on outage events 'internal' to CNPI Tx's system will be subject to a high degree of year-over-year volatility.

III. At CNPI, a one-to-one relationship exists between the transmitter and the customer. A common management and operations team affords each party with an intimate understanding of the respective business units, i.e., transmitter and distributor.

3 Performance Targets

CNPI Tx uses the performance targets in this section to establish threshold levels of acceptable performance before an evaluation of the affected CDP is mandated. CNPI Tx may choose to conduct a performance review when actual values are still within these target values, but any CDP performance outside of these thresholds will require an evaluation.

The values in sections 3.1 and 3.2 define the performance targets to identify when a CDP is an 'Outlier'. That is, whenever the short-term performance at a CDP becomes worse than a particular threshold value.

Section 4 of this documents outlines when and how CNPI Tx determines when the long-term reliability performance of a CDP might also trigger an evaluation.

3.1 CNPI Tx Internal Targets for Outlier Determination (Trigger 1)

As detailed in Section 2 of this CDPPS, CNPI Tx's transmission system is relatively small with only two delivery points serving a single customer. As a result, there is limited data available to perform statistical analysis.

For the time being, CNPI Tx has chosen the targets shown below in Table 1 based on available historical data[1] to ensure that a reliability investigation is triggered whenever the CNPI Tx system's outage performance in any one year exceeds the internal thresholds shown below (i.e. excluding loss-of-supply events from HONI).

Table 1: CNPI Internal Delivery Point Performance Targets based on Load Size

Performance Measure	Delivery Point Performance Target (CNPI Tx Outages Only) (Based on a Delivery Point's Total Average Station Load)			
	0 to 15MW		>15 to 40 MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/year)	N/A	N/A	0.7	1.74
DP Interruption Duration (minutes/year)	N/A	N/A	31	73.0

There are no Customer Delivery Points on CNPI Tx's transmission system with a recent average load less than 15MV or greater than 40MW.

[1] Based on actual CNPI Tx system performance from 2009 to 2013. The historical data for 2012 was adjusted to match the estimated impact if all outages had occurred when the IPL was available. Minimum Standard equals the 5-year average performance plus one standard deviation of performance variability.

3.2 CNPI Tx Total Targets for Outlier Determination (Trigger 2)

For this section, CNPI Tx will use HONI's CDPPS and associated triggers where applicable to measure the aggregate outage performance of both systems with respect to CNPI Tx's two CDP. Table 2 shown below details CNPI Tx's delivery point performance targets based on the demand associated with the delivery point.

(1) These values are based on HONI thresholds outlined in HONI CDPPS, RP-1999-0057/EB-2002-0424 (as revised on Feb 7, 2008). The inclusion of CNPI Tx's performance into HONI's much larger system average performance has a negligible impact on the resulting targets.

(2) These triggering values ensure that the customer served by CNPI Tx's two CDP are not exposed to aggregate reliability performance inclusive of all outages (including those caused by HONI) worse than any other CDP in southern Ontario before triggering an evaluation of that CDP.

Table 2: Gross Delivery Point Performance Targets based on Load Size

Performance Measure	**Delivery Point Performance Target (All Outages)** (Based on a Delivery Point's Total Average Station Load)			
	0 to 15MW		>15 to 40 MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/year)	4.1	9	1.1	3.5
DP Interruption Duration (minutes/year)	89	360	22	140

There are no Customer Delivery Points on CNPI Tx's transmission system with an average load that exceeds 40MW.

As with the HONI CDPPS, these statistics includes all momentary and sustained interruptions caused by forced outages and excludes outages resulting from extraordinary events that have had "excessive" impact on the transmission system (e.g. the 1998 ice storm and the August 2003 Blackout).

Given that CNPI Tx's transmission system is an extension to HONI's transmission system, CNPI Tx's actual delivery point statistics will be calculated inclusive of outages directly attributable to HONI. CNPI Tx will focus on outages attributable to CNPI Tx and will coordinate with HONI to address concerns which may arise from outages attributable to HONI.

4 Performance Standards to Identify "Outliers"

On a regular basis, the Minimum Standard of Performance from both subsections of Section 3 of this document will be used to identify if either of the two Customer Delivery Points should be classified as an "Outlier' due to performance exceeding a minimum threshold.

If either or both of the Customer Delivery Points is deemed to be an "Outlier", CNPI Tx will initiate suitable technical and financial evaluations to address performance, identify the root cause or causes, and determine the prudent course of action to achieve the minimum standard of performance.

Since certain interruptions that impact the CNPI Tx transmission system are expected to originate from the HONI transmission system, CNPI Tx will work with HONI to identify and implement a suitable solution.

5 Performance Standards to Identify "Inliers"

CNPI Tx, as part of its internal Asset Management Program, monitors the performance of its transmission system on a regular basis.

Available historical performance levels will indicate whether or not either of the two Customer Delivery Points is experiencing deteriorating trends in performance notwithstanding the fact that they are satisfactory performers as outlined in section 3.

Specifically, a performance baseline trigger for the frequency and duration of forced (momentary and sustained) interruptions is to be set at each delivery point, based on that delivery point's fixed 5-year 2009 to 2013 average performance, plus one standard deviation (1σ). The performance baseline triggers are to include forced outages resulting from force majéure events, but exclude events which have excessive impact on the transmission system that in CNPI Tx's assessment, strongly skew the historical trend of the measure e.g. tornadoes, earthquakes, and any other significant event having "excessive" impact on performance that is beyond the reasonable control of, and not a result of the fault or negligence of CNPI Tx or HONI.

If either or both of the Customer Delivery Points is deemed to be an "Inlier", CNPI Tx will initiate suitable technical and financial evaluations to address performance, identify the root cause or causes, and determine the prudent course of action to achieve the minimum standard of performance.

If it is determined that such deteriorating trends in performance is partially or fully attributable to HONI's upstream transmission system, CNPI Tx will work with HONI to identify and implement a prudent solution.

6 Remedial Costs to Address Performance “Outliers” and “Inliers”

As specified by the Transmission System Code, CNPI Tx shall not attribute any costs associated with network investments to any customer.

CNPI Tx will cover any remedial costs for initial and financial evaluations.

In addition, CNPI Tx will cover the remedial costs, including appropriate asset maintenance costs which include on-going maintenance and asset replacement to restore/sustain the inherent reliability performance of the existing assets to what was designed originally.

These expenditures are made on an ongoing basis consistent with good utility practices. No customer financial/capital contribution is required for these normal maintenance and sustainment expenditures.

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APPENDIX C

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2015

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Revenue Requirement Workform

Version 4.00

Utility Name	Canadian Niagara Power Inc. – Eastern Ontario Power/Fort Erie/Port Colborne
Service Territory	*Transmission*
Assigned EB Number	EB-2014-0204
Name and Title	Doug Bradbury, Director Regulatory Affairs
Phone Number	905-994-3634
Email Address	doug.bradbury@cnpower.com

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

#	Item	Initial Application	(2)			(6)	Per Board Decision	
1	**Rate Base**							
	Gross Fixed Assets (average)	$39,392,817		($858,581)	$ 38,534,236		$38,534,236	
	Accumulated Depreciation (average)	($17,793,383)	(5)	$49,902	($17,743,481)		($17,743,481)	
	Allowance for Working Capital:							
	Controllable Expenses	$2,012,716		($33,849)	$ 1,978,867		$1,978,867	
	Cost of Power							
	Working Capital Rate (%)		(9)			(9)		(9)
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$4,949,641						
	Distribution Revenue at Proposed Rates							
	Other Revenue:							
	Specific Service Charges							
	Late Payment Charges							
	Other Distribution Revenue							
	Other Income and Deductions							
	Total Revenue Offsets		(7)					
	Operating Expenses:							
	OM+A Expenses	$1,877,416		($56,849)	$ 1,820,567		$1,820,567	
	Depreciation/Amortization	$820,993		($7,306)	$ 813,687		$813,687	
	Property taxes	$135,300		$23,000	$ 158,300		$158,300	
	Other expenses							
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($435,160)	(3)		($371,128)			
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$98,984			$104,670			
	Income taxes (grossed up)	$134,672			$142,408			
	Federal tax (%)	15.00%			15.00%			
	Provincial tax (%)	11.50%			11.50%			
	Income Tax Credits	($525)			($525)			
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			
	Prefered Shares Capitalization Ratio (%)							
		100.0%			100.0%			
	Cost of Capital							
	Long-term debt Cost Rate (%)	6.08%			6.03%		6.03%	
	Short-term debt Cost Rate (%)	2.11%			2.16%		2.16%	
	Common Equity Cost Rate (%)	9.36%			9.30%		9.30%	
	Prefered Shares Cost Rate (%)							

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$39,392,817	($858,581)	$38,534,236	$ -	$38,534,236
2	Accumulated Depreciation (average)	(3)	($17,793,383)	$49,902	($17,743,481)	$ -	($17,743,481)
3	Net Fixed Assets (average)	(3)	$21,599,434	($808,679)	$20,790,755	$ -	$20,790,755
4	Allowance for Working Capital	(1)	$ -	$ -	$ -	$ -	$ -
5	**Total Rate Base**		$21,599,434	($808,679)	$20,790,755	$ -	$20,790,755

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$2,012,716	($33,849)	$1,978,867	$ -	$1,978,867
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$2,012,716	($33,849)	$1,978,867	$ -	$1,978,867
9	Working Capital Rate %	(2)	0.00%	0.00%	0.00%	0.00%	0.00%
10	Working Capital Allowance		$ -	$ -	$ -	$ -	$ -

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$ -	$ -	$ -	$ -	$ -
2	Other Revenue	(1)	$ -	$ -	$ -	$ -	$ -
3	Total Operating Revenues		$ -	$ -	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$1,877,416	($56,849)	$1,820,567	$ -	$1,820,567
5	Depreciation/Amortization		$820,993	($7,306)	$813,687	$ -	$813,687
6	Property taxes		$135,300	$23,000	$158,300	$ -	$158,300
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$2,833,709	($41,155)	$2,792,554	$ -	$2,792,554
10	Deemed Interest Expense		$753,647	($33,622)	$720,025	$ -	$720,025
11	Total Expenses (lines 9 to 10)		$3,587,356	($74,777)	$3,512,579	$ -	$3,512,579
12	**Utility income before income taxes**		($3,587,356)	$74,777	($3,512,579)	$ -	($3,512,579)
13	Income taxes (grossed-up)		$134,672	$7,736	$142,408	$ -	$142,408
14	**Utility net income**		($3,722,029)	$67,041	($3,654,988)	$ -	($3,654,988)

Notes

Other Revenues / Revenue Offsets

Note	Particulars					
(1)	Specific Service Charges	$ -		$ -		$ -
	Late Payment Charges	$ -		$ -		$ -
	Other Distribution Revenue	$ -		$ -		$ -
	Other Income and Deductions	$ -		$ -		$ -
	Total Revenue Offsets	$ -	$ -	$ -	$ -	$ -

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$808,683	$773,416	$773,416
2	Adjustments required to arrive at taxable utility income	($435,160)	($371,128)	($435,160)
3	Taxable income	$373,523	$402,288	$338,256
	Calculation of Utility income Taxes			
4	Income taxes	$98,984	$104,670	$104,670
6	Total taxes	$98,984	$104,670	$104,670
7	Gross-up of Income Taxes	$35,688	$37,738	$37,738
8	Grossed-up Income Taxes	$134,672	$142,408	$142,408
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$134,672	$142,408	$142,408
10	Other tax Credits	($525)	($525)	($525)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$12,095,683	6.08%	$735,418
2	Short-term Debt	4.00%	$863,977	2.11%	$18,230
3	**Total Debt**	60.00%	$12,959,660	5.82%	$753,647
	Equity				
4	Common Equity	40.00%	$8,639,774	9.36%	$808,683
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$8,639,774	9.36%	$808,683
7	**Total**	100.00%	$21,599,434	7.23%	$1,562,330
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$11,642,823	6.03%	$702,062
2	Short-term Debt	4.00%	$831,630	2.16%	$17,963
3	**Total Debt**	60.00%	$12,474,453	5.77%	$720,025
	Equity				
4	Common Equity	40.00%	$8,316,302	9.30%	$773,416
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$8,316,302	9.30%	$773,416
7	**Total**	100.00%	$20,790,755	7.18%	$1,493,442
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$11,642,823	6.03%	$702,062
9	Short-term Debt	4.00%	$831,630	2.16%	$17,963
10	**Total Debt**	60.00%	$12,474,453	5.77%	$720,025
	Equity				
11	Common Equity	40.00%	$8,316,302	9.30%	$773,416
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$8,316,302	9.30%	$773,416
14	**Total**	100.00%	$20,790,755	7.18%	$1,493,442

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		($419,645)		($519,317)		$4,430,324
2	Distribution Revenue	$4,949,641	$419,645	$4,949,641	$519,317	$ -	($4,430,324)
3	Other Operating Revenue Offsets - net	$ -	$ -	$ -	$ -	$ -	$ -
4	**Total Revenue**	$4,949,641	$ -	$4,949,641	$ -	$ -	$ -
5	Operating Expenses	$2,833,709	$2,833,709	$2,792,554	$2,792,554	$2,792,554	$2,792,554
6	Deemed Interest Expense	$753,647	$753,647	$720,025	$720,025	$720,025	$720,025
8	**Total Cost and Expenses**	$3,587,356	$3,587,356	$3,512,579	$3,512,579	$3,512,579	$3,512,579
9	**Utility Income Before Income Taxes**	$1,362,285	($3,587,356)	$1,437,062	($3,512,579)	($3,512,579)	($3,512,579)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($435,160)	($435,160)	($371,128)	($371,128)	($371,128)	($371,128)
11	**Taxable Income**	$927,125	($4,022,516)	$1,065,934	($3,883,707)	($3,883,707)	($3,883,707)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$245,688	($1,065,967)	$282,472	($1,029,182)	($1,029,182)	($1,029,182)
14	**Income Tax Credits**	($525)	($525)	($525)	($525)	($525)	($525)
15	**Utility Net Income**	$1,117,122	($3,722,029)	$1,155,114	($3,654,988)	($2,482,872)	($3,654,988)
16	**Utility Rate Base**	$21,599,434	$21,599,434	$20,790,755	$20,790,755	$20,790,755	$20,790,755
17	Deemed Equity Portion of Rate Base	$8,639,774	$8,639,774	$8,316,302	$8,316,302	$8,316,302	$8,316,302
18	Income/(Equity Portion of Rate Base)	12.93%	-43.08%	13.89%	-43.95%	-29.86%	-43.95%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.30%	9.30%	9.30%	9.30%
20	Deficiency/Sufficiency in Return on Equity	3.57%	-52.44%	4.59%	-53.25%	-39.16%	-53.25%
21	Indicated Rate of Return	8.66%	-13.74%	9.02%	-14.12%	-8.48%	-14.12%
22	Requested Rate of Return on Rate Base	7.23%	7.23%	7.18%	7.18%	7.18%	7.18%
23	Deficiency/Sufficiency in Rate of Return	1.43%	-20.98%	1.84%	-21.30%	-15.66%	-21.30%
24	Target Return on Equity	$808,683	$808,683	$773,416	$773,416	$773,416	$773,416
25	Revenue Deficiency/(Sufficiency)	($308,439)	($4,530,711)	($381,698)	($4,428,404)	$3,256,288	($4,428,404)
26	**Gross Revenue Deficiency/(Sufficiency)**	($419,645) **(1)**		($519,317) **(1)**		$4,430,324 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$1,877,416		$1,820,567		$1,820,567	
2	Amortization/Depreciation	$820,993		$813,687		$813,687	
3	Property Taxes	$135,300		$158,300		$158,300	
5	Income Taxes (Grossed up)	$134,672		$142,408		$142,408	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$753,647		$720,025		$720,025	
	Return on Deemed Equity	$808,683		$773,416		$773,416	
8	**Service Revenue Requirement (before Revenues)**	$4,530,711		$4,428,404		$4,428,404	
9	Revenue Offsets	$ -		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$4,530,711		$4,428,404		$4,428,404	
11	Distribution revenue	$ -		$ -		$ -	
12	Other revenue	$ -		$ -		$ -	
13	**Total revenue**	$ -		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($4,530,711)	**(1)**	($4,428,404)	**(1)**	($4,428,404)	**(1)**

Notes

(1) Line 11 - Line 8

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2016

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Revenue Requirement Workform

Version 4.00

Utility Name	Canadian Niagara Power Inc. – Eastern Ontario Power/Fort Erie/Port Colborne
Service Territory	*Transmission*
Assigned EB Number	EB-2014-0204
Name and Title	Doug Bradbury, Director Regulatory Affairs
Phone Number	905-994-3634
Email Address	doug.bradbury@cnpower.com

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)			(6)		Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$42,783,000		$29,788	$ 42,812,788			$42,812,788	
	Accumulated Depreciation (average)	($18,646,484)	(5)	$45,022	($18,601,462)			($18,601,462)	
	Allowance for Working Capital:								
	Controllable Expenses	$2,057,066		$6,151	$ 2,063,217			$2,063,217	
	Cost of Power								
	Working Capital Rate (%)		(9)			(9)			(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$4,949,641							
	Distribution Revenue at Proposed Rates								
	Other Revenue:								
	Specific Service Charges								
	Late Payment Charges								
	Other Distribution Revenue								
	Other Income and Deductions								
	Total Revenue Offsets		(7)						
	Operating Expenses:								
	OM+A Expenses	$1,919,060		($16,849)	$ 1,902,211			$1,902,211	
	Depreciation/Amortization	$885,209		$17,067	$ 902,276			$902,276	
	Property taxes	$138,006		$23,000	$ 161,006			$161,006	
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($543,275)	(3)		($553,966)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$95,505			$96,397				
	Income taxes (grossed up)	$129,939			$131,152				
	Federal tax (%)	15.00%			15.00%				
	Provincial tax (%)	11.50%			11.50%				
	Income Tax Credits	($525)			($525)				
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%				
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%				
	Cost of Capital								
	Long-term debt Cost Rate (%)	6.08%			6.03%			6.03%	
	Short-term debt Cost Rate (%)	2.11%			2.16%			2.16%	
	Common Equity Cost Rate (%)	9.36%			9.30%			9.30%	
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$42,783,000	$29,788	$42,812,788	$ -	$42,812,788
2	Accumulated Depreciation (average)	(3)	($18,646,484)	$45,022	($18,601,462)	$ -	($18,601,462)
3	Net Fixed Assets (average)	(3)	$24,136,516	$74,810	$24,211,326	$ -	$24,211,326
4	Allowance for Working Capital	(1)	$ -	$ -	$ -	$ -	$ -
5	**Total Rate Base**		$24,136,516	$74,810	$24,211,326	$ -	$24,211,326

(1) **Allowance for Working Capital - Derivation**

6	Controllable Expenses		$2,057,066	$6,151	$2,063,217	$ -	$2,063,217
7	Cost of Power		$ -	$ -	$ -	$ -	$ -
8	Working Capital Base		$2,057,066	$6,151	$2,063,217	$ -	$2,063,217
9	Working Capital Rate %	(2)	0.00%	0.00%	0.00%	0.00%	0.00%
10	Working Capital Allowance		$ -	$ -	$ -	$ -	$ -

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$ -	$ -	$ -	$ -	$ -
2	Other Revenue	(1)	$ -	$ -	$ -	$ -	$ -
3	Total Operating Revenues		$ -	$ -	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$1,919,060	($16,849)	$1,902,211	$ -	$1,902,211
5	Depreciation/Amortization		$885,209	$17,067	$902,276	$ -	$902,276
6	Property taxes		$138,006	$23,000	$161,006	$ -	$161,006
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$2,942,275	$23,218	$2,965,493	$ -	$2,965,493
10	Deemed Interest Expense		$842,171	($3,685)	$838,487	$ -	$838,487
11	Total Expenses (lines 9 to 10)		$3,784,446	$19,533	$3,803,980	$ -	$3,803,980
12	**Utility income before income taxes**		($3,784,446)	($19,533)	($3,803,980)	$ -	($3,803,980)
13	Income taxes (grossed-up)		$129,939	$1,214	$131,152	$ -	$131,152
14	**Utility net income**		($3,914,385)	($20,747)	($3,935,132)	$ -	($3,935,132)

Notes

Other Revenues / Revenue Offsets

Notes	Particulars					
(1)	Specific Service Charges	$ -		$ -		$ -
	Late Payment Charges	$ -		$ -		$ -
	Other Distribution Revenue	$ -		$ -		$ -
	Other Income and Deductions	$ -		$ -		$ -
	Total Revenue Offsets	$ -	$ -	$ -	$ -	$ -

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$903,671	$900,661	$900,661
2	Adjustments required to arrive at taxable utility income	($543,275)	($553,966)	($543,275)
3	Taxable income	$360,396	$346,695	$357,386
	Calculation of Utility income Taxes			
4	Income taxes	$95,505	$96,397	$96,397
6	Total taxes	$95,505	$96,397	$96,397
7	Gross-up of Income Taxes	$34,434	$34,755	$34,755
8	Grossed-up Income Taxes	$129,939	$131,152	$131,152
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$129,939	$131,152	$131,152
10	Other tax Credits	($525)	($525)	($525)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$13,516,449	6.08%	$821,800
2	Short-term Debt	4.00%	$965,461	2.11%	$20,371
3	**Total Debt**	60.00%	$14,481,910	5.82%	$842,171
	Equity				
4	Common Equity	40.00%	$9,654,606	9.36%	$903,671
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,654,606	9.36%	$903,671
7	**Total**	100.00%	$24,136,516	7.23%	$1,745,842

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$13,558,343	6.03%	$817,568
2	Short-term Debt	4.00%	$968,453	2.16%	$20,919
3	**Total Debt**	60.00%	$14,526,796	5.77%	$838,487
	Equity				
4	Common Equity	40.00%	$9,684,530	9.30%	$900,661
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,684,530	9.30%	$900,661
7	**Total**	100.00%	$24,211,326	7.18%	$1,739,148

Per Board Decision

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
8	Long-term Debt	56.00%	$13,558,343	6.03%	$817,568
9	Short-term Debt	4.00%	$968,453	2.16%	$20,919
10	**Total Debt**	60.00%	$14,526,796	5.77%	$838,487
	Equity				
11	Common Equity	40.00%	$9,684,530	9.30%	$900,661
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$9,684,530	9.30%	$900,661
14	**Total**	100.00%	$24,211,326	7.18%	$1,739,148

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		($132,299)		($120,715)		$4,828,926
2	Distribution Revenue	$4,949,641	$132,299	$4,949,641	$120,715	$ -	($4,828,926)
3	Other Operating Revenue Offsets - net	$ -	$ -	$ -	$ -	$ -	$ -
4	**Total Revenue**	$4,949,641	$ -	$4,949,641	$ -	$ -	$ -
5	Operating Expenses	$2,942,275	$2,942,275	$2,965,493	$2,965,493	$2,965,493	$2,965,493
6	Deemed Interest Expense	$842,171	$842,171	$838,487	$838,487	$838,487	$838,487
8	**Total Cost and Expenses**	$3,784,446	$3,784,446	$3,803,980	$3,803,980	$3,803,980	$3,803,980
9	**Utility Income Before Income Taxes**	$1,165,195	($3,784,446)	$1,145,661	($3,803,980)	($3,803,980)	($3,803,980)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($543,275)	($543,275)	($553,966)	($553,966)	($553,966)	($553,966)
11	**Taxable Income**	$621,920	($4,327,721)	$591,695	($4,357,946)	($4,357,946)	($4,357,946)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$164,809	($1,146,846)	$156,799	($1,154,856)	($1,154,856)	($1,154,856)
14	**Income Tax Credits**	($525)	($525)	($525)	($525)	($525)	($525)
15	**Utility Net Income**	$1,000,911	($3,914,385)	$989,387	($3,935,132)	($2,648,599)	($3,935,132)
16	**Utility Rate Base**	$24,136,516	$24,136,516	$24,211,326	$24,211,326	$24,211,326	$24,211,326
17	Deemed Equity Portion of Rate Base	$9,654,606	$9,654,606	$9,684,530	$9,684,530	$9,684,530	$9,684,530
18	Income/(Equity Portion of Rate Base)	10.37%	-40.54%	10.22%	-40.63%	-27.35%	-40.63%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.30%	9.30%	9.30%	9.30%
20	Deficiency/Sufficiency in Return on Equity	1.01%	-49.90%	0.92%	-49.93%	-36.65%	-49.93%
21	Indicated Rate of Return	7.64%	-12.73%	7.55%	-12.79%	-7.48%	-12.79%
22	Requested Rate of Return on Rate Base	7.23%	7.23%	7.18%	7.18%	7.18%	7.18%
23	Deficiency/Sufficiency in Rate of Return	0.40%	-19.96%	0.37%	-19.97%	-14.66%	-19.97%
24	Target Return on Equity	$903,671	$903,671	$900,661	$900,661	$900,661	$900,661
25	Revenue Deficiency/(Sufficiency)	($97,240)	($4,818,056)	($88,726)	($4,835,793)	$3,549,260	($4,835,793)
26	**Gross Revenue Deficiency/(Sufficiency)**	($132,299) **(1)**		($120,715) **(1)**		$4,828,926 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$1,919,060		$1,902,211		$1,902,211	
2	Amortization/Depreciation	$885,209		$902,276		$902,276	
3	Property Taxes	$138,006		$161,006		$161,006	
5	Income Taxes (Grossed up)	$129,939		$131,152		$131,152	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$842,171		$838,487		$838,487	
	Return on Deemed Equity	$903,671		$900,661		$900,661	
8	**Service Revenue Requirement (before Revenues)**	$4,818,056		$4,835,793		$4,835,793	
9	Revenue Offsets	$ -		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$4,818,056		$4,835,793		$4,835,793	
11	Distribution revenue	$ -		$ -		$ -	
12	Other revenue	$ -		$ -		$ -	
13	**Total revenue**	$ -		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($4,818,056)	(1)	($4,835,793)	(1)	($4,835,793)	(1)

Notes

(1) Line 11 - Line 8

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APPENDIX D

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Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
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2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

VIA EMAIL AND WEB POSTING

July 17, 2012

TO: Licensed Electricity Distributors
All Other Interested Parties

RE: Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013

This letter serves to provide the Board's regulatory accounting policy direction to electricity distributors on matters arising from the one-year deferral option for the IFRS changeover in 2012. 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. The Board however will require that these changes be mandatory in 2013 for all distributors that have not yet made these changes, even if there is a further option to defer IFRS changeover in 2013. A new variance account is created and authorized for distributors to record the financial differences arising from these accounting changes.

Background

The Canadian Accounting Standards Board ("AcSB") announced in March 2012 that it would allow rate-regulated entities a one-year deferral option for the IFRS changeover in 2012. In light of the AcSB's announcement, the Board issued a letter to electricity distributors on April 30, 2012 and provided direction regarding this deferral option. The letter indicated, among other things, that,

- The Board will not require regulatory accounting and reporting for 2012 to be in modified IFRS ("MIFRS") if a distributor is not required to adopt IFRS for financial reporting and opts to remain on CGAAP.
- For those distributors that have transitioned to IFRS or whose rates are set based on MIFRS, the Board expects these distributors to conduct regulatory accounting and reporting for 2012 in MIFRS.

The Board has received numerous inquiries for regulatory accounting direction from distributors requesting to make changes to their depreciation rates (for example, using the *Depreciation Study for Use by Electricity Distributors* (EB-2010-0178), (the “Kinectrics Report”) or own depreciation study) and capitalization policies while still under CGAAP in 2012. Several distributors indicated that they have already completed sufficient detailed accounting work in these areas in their transition to IFRS, and as such, they are positioned and wish to make these accounting changes while still under CGAAP in 2012. They are seeking accounting direction on whether the Board will allow these accounting changes, and if so, what would be the approval process.

Regulatory accounting policy direction regarding Changes to the Depreciation Expense and Capitalization Policies

A key benefit that was expected to be derived from the Board’s established accounting policies under the IFRS 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 (with a few exceptions, for example, distributors adopting US GAAP).

There were several distributors that have adopted these and other accounting changes for regulatory purposes including ratemaking in their 2012 cost of service applications which were approved by the Board. The same approach is expected from distributors filing 2013 cost of service rate applications, which are required to be filed on an MIFRS basis. The Board encourages and will permit distributors that have deferred the changeover to IFRS in 2012 to also implement regulatory accounting changes for depreciation expense and capitalization policies effective on January 1, 2012. The Board however will require that these changes be mandatory in 2013 (i.e., effective on January 1, 2013) for those distributors that do not elect to make these accounting changes in 2012 regardless of whether the AcSB permits further deferrals beyond 2012 for the changeover to IFRS. These accounting changes should be implemented consistent with the Board’s regulatory accounting policies as set out for modified IFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards,* EB-2008-0408, the Kinectrics Report, and the Revised 2012 *Accounting Procedures Handbook for Electricity Distributors* (“APH”).

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.

Account 1576 and Accounting Requirements

The Board has approved a new variance Account 1576, Accounting Changes Under CGAAP, for distributors to record the financial differences arising as a result of the election to make these accounting changes under CGAAP in 2012 or to make these changes as mandated by the Board in 2013, if applicable.

The account description of Account 1576 and the associated accounting requirements, including an illustrative example, are provided in the July 2012 *Accounting Procedures Handbook – Frequently Asked Questions* (see question and answer #2) posted on the Board's website at www.ontarioenergyboard.ca.

Distributors are expected to reflect these accounting changes in their CGAAP-based financial statements since rate-regulated accounting is recognized in CGAAP.

Any questions regarding the above should be directed to the Market Operations Hotline at 416-440-7604 or by e-mail at market.operations@ontarioenergyboard.ca. The Board's toll free number is 1-888-632-6273.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

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APPENDIX E

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Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2010-0159

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 Canadian Niagara Power Inc., requesting approval to establish a deferral account to record certain preliminary costs.

BEFORE: Ken Quesnelle
Presiding Member

Paula Conboy
Member

DECISION WITH REASONS

August 18, 2010

THE APPLICATION

Canadian Niagara Power Inc. (the “Applicant” or “CNPI”) filed an application with the Ontario Energy Board, (the “Board”) dated April 9, 2010 requesting Board approval to establish a deferral account. The purpose of the account would be to record costs associated with the preliminary work and the making of an application by CNPI for leave to construct certain transmission facilities with the intent to seek disposition of the account balance through a prudence review in a future cost of service rate setting proceeding. The leave to construct application was ultimately denied by the Board. CNPI owns and operates distribution and transmission systems in Ontario. This application is in respect to CNPI’s transmission business.

The Board assigned File No. EB-2010-0159 to this application.

BACKGROUND

On July 16, 2009, CNPI filed an application (EB-2009-0283) under section 92 of the *Energy Board Act 1998 (*the *“*Act) for an order of the Board granting leave to construct transmission facilities in the Niagara Falls / Fort Erie area to reinforce its existing 115 kilovolt transmission system (the “Project”). On March 29, 2010, the Board issued a decision in which it denied CNPI’s leave to construct application. Consequently, CNPI will not be proceeding with the Project. In its April 9, 2010 application letter, CNPI advised that it had made what it considered to be a substantial investment in preliminary costs for the Project amounting to approximately $1.5 million (the “Preliminary Costs”).

CNPI has requested that it be permitted to establish a deferral account to record its Preliminary Costs for the Board’s consideration in a future proceeding. Depending on the outcome of that future proceeding, CNPI could then be granted approval to recover the Preliminary Costs from Ontario ratepayers through the Uniform Transmission Rates.

THE PROCEEDING

- The Board issued a Notice of Application and Hearing (the “Notice”) on April 28, 2010. The Notice and the application were served by the Applicant and posted on the Applicant’s website, as directed by the Board.
- Energy Probe Research Foundation (“Energy Probe”) applied for and was granted intervenor status.
- The Board proceeded with this case by way of a written hearing.

- Board staff and Energy Probe filed interrogatories on June 4 and 7, 2010, respectively.
- CNPI filed responses to the interrogatories on June 15, 2010.
- CNPI filed its closing submission on June 22, 2010.
- Board staff and Energy Probe filed submissions on July 5, 2010.
- CNPI filed its reply submission on July 9, 2010.

EVIDENCE

Details and Timing of Spending

Based on the prefiled evidence, CNPI made what it considered to be a substantial investment in preliminary work (the “Preliminary Costs”) associated with the leave to construct application (EB-2009-0283). Below is a summary of the Preliminary Costs that CNPI has proposed to be included in a new deferral account.

System Impact Studies:	$250,000
Engineering, Environmental and Financial Studies:	$665,000
Accumulated interest during work in progress:	$209,000
Representation costs and internal costs related to the impact studies and the Application:	$376,000
Total	**$1,500,000**

Based on CNPI’s evidence, the expenditures were made in the timeframe from late 2003 until the completion of the record in the EB-2009-0283 proceeding in early 2010.

CNPI began preliminary evaluation of the Project in December 2003. Throughout 2004 and 2005, CNPI invested modestly to evaluate the Project. In December 2005, CNPI began more formal work with payments being made to the Independent Electricity System Operator (“IESO”), the New York Independent System Operator (“NYISO”) and Hydro One Networks Inc. for feasibility, system and customer impact studies, respectively.

Work related to the system impact studies, preliminary engineering, land ownership reviews and application preparation continued until the submission of the application on July 16, 2009.

Further costs were incurred during the application review process to respond to the various interrogatories posed by Board staff and intervenors.

Timing of the Application and Rationale

This application for the deferral account was filed with the Board on April 9, 2010, about 11 days after the Board's decision on the leave to construct application.

CNPI submitted that it did not request a deferral account prior to its decision to proceed with the leave to construct application for the following reasons:

- CNPI had a reasonable expectation, based on results of system impact studies and "the positive response from IESO staff", that the leave to construct application would be approved and consequently the subject development costs would have been capitalized with the other development and construction costs related to the project. Until capitalization, CNPI recorded the preliminary costs in Account 2055 "Construction Work in Progress".

- CNPI indicated that it is not certain about the appropriateness of keeping the Preliminary Costs in the 2055 Construction Work in Progress account since that account contemplates the completion of the work. Therefore, CNPI sought approval to record its Preliminary Costs in a new deferral account.

- CNPI submitted that, if it is the Board's preference that the Preliminary Costs remain in Account 2055 for potential disposition at CNPI's next transmission cost of service rate application, CNPI would not object.

- CNPI submitted that it had not considered using one of the deferral accounts included in the Uniform System of Accounts since, given the Board decision in the leave to construct application, "it would be prudent to seek the Board's leave prior to establishing a balance in such a deferral account".

- CNPI submitted that it should have the opportunity, at its next transmission cost of service rate application, to establish that the Preliminary Costs were prudent.

- CNPI makes reference, in its submission, to the Board's Notice of Proposal to Amend a Code (EB-2008-0003), which states that "a transmitter that has been designated by the Board to undertake development activities in relation to an enabler facility will be permitted to recover all of the prudently incurred costs associated with those activities, even if the enabler facility does not proceed to construction". CNPI also makes reference to Board staff's discussion paper regarding transmission project development planning (EB-2010-0059) where CNPI states that the same concept is proposed by Board staff.

Position of the Parties

Energy Probe, in its interrogatories, questioned whether CNPI's request to establish a deferral account to record Preliminary Costs meets the Board's criteria for the establishment of such an account (causation, materiality, management inability to control and prudence). In its responses, CNPI submitted that the above noted criteria apply to distributors who are applying to recover Z-factor costs (extraordinary, unpredictable and unmanageable costs) and do not apply to this application because CNPI is not applying to recover Z-factor costs. However, CNPI went on to explain that its proposal does meet the criteria.

Board staff, in its interrogatories and submission, raised the issue of retroactivity regarding the timing of when the Preliminary Costs were incurred as compared to when these costs were proposed to be recorded in the deferral account. Board staff submitted that the Board is not authorized to set rates retroactively. Any expenses that a utility wishes to recover from its ratepayers must either be in its Board approved rates tariff, or recorded in an authorized deferral or variance account until such time as the disposition of the account balance in rates is approved. In most cases, a deferral account should be approved before the expenses in question are recorded in the account. If this were not the case, then any distributor or transmitter could seek after the fact approval for out of period expenses simply by requesting a deferral account after the expenses were incurred. This would amount to retroactive ratemaking.

CNPI submitted that the future recovery of the Preliminary Costs would not constitute retroactive ratemaking since development, engineering and construction costs are recorded in Account 2055 and "simply because the project will not be completed does not mean that the recovery of CNPI's Preliminary Costs would amount to retroactive ratemaking".

BOARD FINDINGS

Timing of Expenditures and Application

In the Board's view, the main issue in this case is whether CNPI's proposal is appropriate and reasonable in terms of the timing of the spending in relation to the approval sought to establish the proposed deferral account. Regulatory policy, practices, and tenets of cost of service rate making that make up the regulatory compact must be considered in this case.

One of the main tenets of cost of service rate making is the matching of future revenues with anticipated future costs. A company files an application for rates that will recover a revenue requirement for its anticipated costs over a future test period. The anticipated costs of service are typically illustrated through a presentation of anticipated activities related to the ongoing operation of the company's assets as well as capital replacements and expansion plans. Ratepayers are afforded the opportunity to provide comments that are informed by the company's total spending plan. The Board then issues its final decision setting rates in accordance with what it considers to be just and reasonable. The company is then required to manage its costs within the envelope of its incoming revenue between these rebasing periods. Ratepayers should have confidence in the rates they will be charged in the intervals between rebasing milestones.

The Board notes that CNPI has not filed a rate application since 2001 and therefore its revenue requirement underpinning the approved rates has remained constant at $4,612,443 since that time. CNPI is expected to work within its revenue envelope until such time as the company files an application for, and the Board approves a new transmission rate based on a newly substantiated revenue requirement. If, in between rate cases, there are anticipated expenses or capital costs that the company can not afford, it should come to the Board on a prospective basis and seek relief. This includes and in the particular circumstances of this application, the possibility that current expenses may arise due to situations where development costs for capital works can't be capitalized because the projects may never come into use.

The Board notes that the anticipated cost of the project in question was in excess of $30M. CNPI's rate base as of the year 2000 from its filing in 2001 was approximately $22M. Irrespective of the dated information on CNPI's rate base, the Board considers that the size of the project relative to CNPI's existing system to be very substantial and that the sheer size of the project should have driven CNPI to consider these matters more carefully.

The manner in which the company seeks relief can either be in the form of a cost of service application or, if there is sufficient uncertainty in the amount of the future expenses or capital costs, the applicant can seek a deferral or variance account prior to incurring the costs for future disposition. The merits of the cost drivers and the probability of the assets coming into use would be tested at that time.

The Board is not convinced that there is anything particular to CNPI's situation that would compel the Board to deviate from a well established tenet of rate making. If CNPI foresaw expenses that it could not afford within its current revenue envelope it should have applied to the Board prior to incurring the expenses to have the merits of its new revenue requirement tested.

CNPI referenced the Board's Notice of Proposal to Amend a Code (EB-2008-0003) as well as to Board staff's discussion paper regarding transmission project development planning (EB-2010-0059) in support of its application. CNPI submitted that establishing a deferral account for its Preliminary Costs would be akin to a transmitter that has been designated by the Board to undertake development activities in relation to an enabler facility being permitted to recover all of the prudently incurred costs associated with those activities, even if the enabler facility does not proceed to construction. CNPI referenced the Board staff discussion paper as proposing the same concept. The Board considers this line of reasoning to be flawed. There has been no proceeding involving CNPI akin to the Board's anticipated "designation" process in which the merits of the development activity would have been examined in advance. It would be on the basis of the Board's conclusions on those merits that costs would be recoverable in the event that the project did not come to fruition.

Criteria for Establishing a Deferral Account

There were substantial interrogatories and submissions from Energy Probe and CNPI on whether or not the four criteria mentioned above apply to this case. In the Board's view, deferral accounts are for the current period or future costs. This includes Z-factor costs which are recorded in a deferral account (1572 - Extraordinary Event Costs) provided that they ultimately meet the criteria mentioned above. The Board accepts CNPI's position that the Preliminary Costs are not Z-factor costs. In addition, there is no other provision for establishing a deferral account for expenditures that have already been made in relation to costs incurred in a prior year.

CONCLUSION

Based on the above evidence and findings, the Board denies CNPI's application requesting Board approval to establish a deferral account to record Preliminary Costs associated with the transmission facilities that were the subject of the leave to construct application EB-2009-0283.

Cost Awards

Energy Probe may submit cost claims by **August 30, 2010**, in accordance with the Board's Practice Direction on Cost Awards.

CNPI will have until **September 13, 2010** to object to any aspect of the costs claimed.

Energy Probe will have until **September 20, 2010** to respond as to why their cost claim should be allowed. Copies of its submissions must be filed with the Board and served on CNPI.

DATED at Toronto, August 18, 2010
ONTARIO ENERGY BOARD

Original signed by

Ken Quesnelle
Presiding Member

Original signed by

Paula Conboy
Member

APPENDIX F

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EB-2014-0204

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Canadian Niagara Power Inc. for an Order or Orders pursuant to Section 78 of the *Ontario Energy Board Act, 1998* approving rates for the transmission of electricity and related matters.

Draft Accounting Order

Canadian Niagara Power Inc. (CNPI Tx) filed a complete cost of service application with the Ontario Energy Board (OEB) on November 17, 2014 under section 78 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to its electricity transmission revenue requirements for 2015 and 2016 to be effective January 1, 2015 and January 1, 2016. CNPI Tx recovers its OEB-approved revenue requirement through Ontario's Uniform Transmission Rates.

On December 18, 2014, the OEB declared the CNPI Tx's existing revenue requirement interim effective January 1, 2015[1].

In their Submission made on March 30, 2015, Board staff has submitted that in the event that the OEB approves January 1, 2015 as the effective date that a deferral account be established to record the foregone revenue for future disposition. OEB staff requested that CNPI Tx include a draft accounting order for such an account in its reply submission.

This draft Accounting Order is intended to reflect the Board staff's request.

[1] EB-2014-0204, Order for Interim Rates, December 18, 2014

CNPI shall establish the following deferral and variance accounts effective January 1, 2015:

Account 1508 Other Regulatory Assets – Foregone Revenue

- Sub-account Network
- Sub-account Line Connection
- Sub-account Transformation Connection

As of the implementation date of CNPI Tx's 2015 Revenue Requirement, as approved by the Board, CNPI will retrospectively record the difference between revenues received on the basis of the CNPI Tx Interim Revenue Requirement and the Board approved 2015 Revenue Requirement. Entries will be made with respect of each month, effective January 1, 2015, until such period that the 2015 Revenue Requirement is implemented. No further entries shall be made to the foregone revenue deferral account effective the implementation date.

Disposition of Account 1508 Other Regulatory Assets – Foregone Revenue is proposed to occur in a subsequent application before the Board. CNPI will submit the balances of the Account 1508 Other Regulatory Assets – Foregone Revenue to the Board for a prudence review. Upon acceptance by the Board of the Account 1508 Other Regulatory Assets – Foregone Revenue, the balance of each sub-account, described above, will be disposed of in a manner as determined by the Board.

CNPI will not record any principal transactions in the above deferral and variance accounts after submitting the balances for prudence review.

Carrying charges will be recorded on this account.

Sample Journal Entries

The following are examples of the journal entries that will be made by CNPI Tx. The amounts shown are intended for illustrative purposes only.

Entry 1 (on effective date of EB-2014-0204):		
Dr. Account 1508 Other Regulatory Assets - Foregone Revenue, Sub-Account Network	20,000	
Dr. Account 1508 Other Regulatory Assets - Foregone Revenue, Sub-Account Line Connection	20,000	
Dr. Account 1508 Other Regulatory Assets - Foregone Revenue, Sub-Account Transformation Connection	20,000	
Cr. Account 4110 Transmission Services Revenue		60,000
To record foregone revenue.		