ONTARIO ENERGY BOARD

COMMISSION DE L'ÉNERGIE DE L'ONTARIO

DECISION AND ORDER

Niagara Peninsula Energy Inc.
2015 Electricity Distribution Rates

EB-2014-0096

May 14, 2015

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EB-2014-0096

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 Niagara Peninsula Energy Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2015

BEFORE: Christine Long
Presiding Member

Allison Duff
Member

Decision and Order
May 14, 2015

Introduction

Niagara Peninsula Energy Inc. (NPEI) filed a cost of service application seeking approval from the Ontario Energy Board (OEB) to change the rates NPEI charges for electricity distribution effective May 1, 2015 (the Application). NPEI is the electricity distributor that serves approximately 51,500 customers in the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln, and the Town of Pelham.

If the Application is approved as filed, a typical residential customer (consuming 800 kWh per month) would see their rates increase by $0.81 per month on the delivery portion of the bill. For a small general service customer, (consuming 2,000 kWh per month), there would be a reduction of $4.21 per month on the delivery portion of the bill.

In order to determine the rates NPEI can charge its customers, the OEB first determines how much revenue NPEI should be allowed to recover from its customers. This amount is known as the revenue requirement. The proposed revenue requirement includes many factors, including the company's expected operating and maintenance costs and expected capital investments, necessary to provide reliable and cost–effective service. The revenue requirement, coupled with forecasts of the number of customers and those customers' energy needs, are used to determine the proposed rates. It is up to the OEB to approve the specific rates a utility can charge its customers.

Process

In reaching its findings, the Board was aided by the participation of three intervenors; Energy Probe Research Foundation (Energy Probe), the Vulnerable Energy Consumers Coalition (VECC) and the School Energy Coalition (SEC). OEB staff also participated in the proceeding.

A settlement conference took place on February 3, 2015 in which NPEI, Energy Probe, VECC and SEC (the Parties) discussed the issues in the Application. The Parties reached a partial settlement on many of the issues and filed a Settlement Proposal. OEB staff participated in the settlement discussions and supported the Settlement Proposal. A copy of the Settlement Proposal is attached as Appendix A.

There were two issues which the Parties were unable to agree upon: the amount of cash required to operate the business on a day-to-day basis given the time lag between when services are paid and payments are received from customers (the working capital allowance), and the percentage of revenue that should be recovered from residential customers through the fixed and variable service charges.

The Board heard the unsettled issues at an oral hearing. This Decision addresses the Settlement Proposal and the two unsettled issues, namely the working capital allowance and the fixed-variable rate split for the residential customer class.

After implementing the findings of this Decision, NPEI will provide the Board with a final calculation of its rates and charges. At that point, the Board will determine final rates and the impact these rates will have on NPEI's customers.

The Settlement Proposal

The Parties settled on the following major components of the company's costs:

	Application	Settlement	Change	
Operating, Maintenance & Administration	$16,754,348	$16,137,763	-$616,585	-3.7%
Capital Expenditures	$11,185,268	$10,571,580	-$613,688	-5.5%
Return	$8,949,680	$8,645,215	-$304,465	-3.4%

The net effect of all changes in the Settlement Proposal is a reduction in the revenue requirement of $703,615 from the amount proposed in the Application. Of the two unsettled issues, only the working cash allowance affects the revenue requirement calculation. The Parties agreed to use a working capital allowance of 13% as a placeholder, pending the Board's Decision, for the purpose of the calculations included in the Settlement Proposal. The second unsettled issue, the fixed-variable rate split affects rate design, not the revenue requirement calculation.

After the oral hearing, the Parties amended the Settlement Proposal (the Amended Settlement Proposal) in order to address questions from the Board and clarify NPEI's ability to seek rate relief for unforeseen events beyond its control. The Amended Settlement Proposal was filed on March 25, 2015 prior to the filing of submissions.[1]

Findings

The Board accepted the Settlement Proposal at the oral hearing and accepted the rate effects as reasonable, subject to its findings on the two unsettled issues.

The Board reminds parties that, since settlements are the result of negotiations on numerous interconnected and sometimes complex issues, the terms of a settled issue in one proceeding may not necessarily be accepted by the Board in other proceedings.

Residential Rate Design

The fixed-variable rate split for residential customers is an unsettled issue. During the settlement process, the Parties were unable to agree on the appropriate division between fixed and variable charges for residential customers. In the Application, NPEI

[1] Amended Partial Settlement Proposal, March 25, p. 34

proposed to recover 65% of revenues from the fixed monthly service charge and 35% from the variable charge from energy consumed.

After the oral hearing, NPEI revised its proposal from 65%-35% to the current fixed-variable rate split of 58%-42% based on an analysis filed as an undertaking response. Energy Probe, VECC and SEC supported the revised proposal. OEB staff did not oppose the revised proposal, but noted that OEB policy is moving in the direction of increasing fixed charges among the residential class.[2]

Findings

The Board finds it appropriate to maintain the current fixed-variable rate split for the residential customer class. The Board directs NPEI to maintain the current 58%-42% fixed-variable split pending any new policies issued by the OEB regarding distribution rate design for residential customers.

NPEI indicated that it had not sought customer feedback regarding its original proposal to change the residential fixed-variable rate split. In response to questions from the Board during the oral hearing, NPEI clarified that its consumer engagement evidence included a customer survey, yet the survey was conducted before the Application was prepared. The Board would find it useful if customer engagement activities encompassed any proposed changes included in an application, especially changes directly affecting customers.

Working Capital Allowance

The working capital allowance (WCA), is the cash required by the utility because of the time lag between when money is spent to provide distribution services and when money is received in payment for those services from customers.

In its Application, NPEI requested a 13% WCA of eligible controllable expenses, taxes and the cost of power. NPEI submitted that 13% was consistent with the OEB's Filing Requirements.[3] The 13% WCA proposal resulted in $20.8 million being added to rate base.

[2] In the time since the OEB staff submission, the policy has been confirmed in *EB-2012-0410, A New Distribution Rate Design for Residential Electricity Customers, issued April 2, 2015*
[3] Filing Requirements For Electricity Distribution Rate Applications - 2014 Edition for 2015 Rates Applications

The Filing Requirements suggest one of two approaches to determine the WCA: either a default allowance of 13% or a percentage derived from a utility-specific lead/lag study. NPEI did not conduct a lead/lag study for this proceeding. The OEB had not directed NPEI to file a study. In the Settlement Proposal, NPEI agreed to complete and file a lead/lag study prior to its next cost of service application.

Intervenors argued that 13% was too high given the evidence filed in the proceeding. In particular, intervenors focused on NPEI's change in billing practice since May 10, 2010 when it starting billing all customers on a monthly basis. Prior to that date, more than half of customers had been billed once every two months.

The WCA is affected by the length of the billing period. With a shorter billing period, cash is collected from customers more frequently and less cash is required from other sources to pay for expenses and other financial obligations.

Energy Probe submitted that NPEI had calculated a saving of $3 million associated with the change in billing practice. NPEI's management had provided the $3 million estimated savings to support and obtain approval for the billing change from its Board of Directors. Utilizing the $3 million estimate filed in this proceeding with information available from NPEI's last cost of service proceeding (EB-2010-0138), Energy Probe submitted that the WCA should be $16 million or 9.5%, which would reduce the revenue requirement by $410,000.

Energy Probe also submitted that the source of the 13% default was out-of-date. Energy Probe argued that the OEB's 13% WCA value was derived from lead/lag studies of four utilities, three of which have now filed updated lead/lag studies with the OEB and result in an updated WCA of 9.54%. Energy Probe cited Navigant, (the consultant who prepared the three updated lead/lag studies), as stating the prior lead/lag studies, which formed the basis of the 13% default, utilized an "obsolete methodology". Energy Probe characterized the 13% default as a benchmark, but argued that the OEB should rely upon benchmarks that reflect the best available information at the time.

VECC analyzed NPEI's actual average working capital from 2011 to 2013. From its analysis, VECC recommended a WCA of 10%. VECC submitted that in the absence of a lead/lag study for NPEI, utilizing the historical average of 10% was appropriate for setting rates in 2015.

VECC referred to prior OEB decisions in which the Board was reluctant to use the lead/lag study results from one utility with monthly billing practices and apply those results to another utility. However, the 13% default in the Filing Requirements was calculated utilizing the lead/lag study results from other utilities, which appeared contradictory. VECC submitted that the 13% was out-of-date and too high and as a result, created an inherent bias as any utility with estimated working capital needs lower than 13% would not initiate a lead/lag study on its own. As a result of this inherent bias for utilities to propose the 13% default, there was an asymmetrical risk for customers of rates being too high.

SEC also submitted the 13% was excessive and that this proceeding was unique as evidence had been filed by NPEI quantifying a $3 million saving for adopting monthly billing for all customers. SEC indicated that the evidence filed in this proceeding was sufficient for the Board to approve a WCA other than 13%. However, if the Board was still not satisfied with the evidence in this proceeding, the Board could declare interim rates until NPEI filed a lead-lag study. SEC proposed an August 31, 2015 deadline be established for NPEI to commission and file a lead/lag study with the OEB.

OEB staff submitted that NPEI had calculated the WCA in accordance with OEB policy and cited a recent finding of the OEB, which stated that:

> The OEB finds that using a consistent WCA default value in cases where lead/lag studies have not been conducted to be a better approach than attempting to use simplified methods to derive a utility-specific WCA value for each case from other lead/lag studies which may not reflect the unique circumstances of such utility.[4]

OEB staff submitted that there is no evidence that would suggest a specific reduction in WCA should be directly applied to NPEI.

Findings

The Board directs NPEI to conduct a lead/lag study and file the study with the OEB with its next incentive rates application. The Board is not convinced based on the evidence in this case that the default value of 13% is appropriate. However, the Board does not

[4] EB-2013-0147/EB-2014-0055, Decision and Order, October 23, 2014, page 4

have enough evidence before it to approve an alternate WCA. As a result, the Board is ordering NPEI to conduct its own lead/lag study. The Board appreciates that NPEI offered, as part of this current application, to file a study prior to its next cost of service application, but the Board is concerned that the filing of that application may not be for five years.

The OEB has allowed utilities to rely on the 13% default value in other cost of service proceedings, when it determined that the evidence provided did not warrant a departure from the default value. The Board finds the evidence in this proceeding and NPEI's business circumstances to be unique. Evidence was filed which indicated a $3 million savings to the utility as a result of moving to monthly billing. However, NPEI's witnesses also testified that the estimated savings were never verified or quantified after the billing change was implemented. Evidence was filed regarding the increase in the cost of power in recent years and the associated balances aggregated in variance accounts. NPEI's witness indicated that the cost of power had increased by $35 million since its last rates application and that the cost of power increases had led to higher monthly customer bills.[5] [6] In addition, the Board is concerned with the additional financing obtained by NPEI to operate its business in 2014. Establishing the appropriate WCA to be recovered in 2015 rates should be sufficient to maintain the financial viability of the utility without an undue reliance on short-term debt.

The Board finds that conducting a lead/lag study would be in the best interest of NPEI, its shareholder and its customers in order to set just and reasonable rates. NPEI's 2015 rates will be maintained on an interim basis, pending the lead/lag study. The lead/lag study should be filed as part of NPEI's next incentive rates application for review. NPEI's 2015 final rates should be based on its actual, approved working capital needs.

The Board has made its Decision requiring NPEI to conduct a lead/lag study while recognizing that the OEB's policy work in this area is on-going, as indicated in the Draft Report of the Board on Billing Practices, issued on September 18, 2014.

The Board directs NPEI to establish a new deferral account to capture all incremental costs associated with the study, both internal and external costs to ensure NPEI is not financially affected by the Board's directive. NPEI is also directed to file a draft accounting order with the draft Rate Order.

[5] TR. Vol. 1, p. 71
[6] Tr. Vol. 1 p. 46

Conclusion

The Board issued a Rate Order on April 28, 2015 declaring NPEI’s existing rates interim on May 1, 2015. As a result of this Decision, new rates for 2015 will be based on the Amended Settlement Proposal, utilizing a 13% WCA. The new 2015 rates will be implemented and effective as of June 1, 2015 and remain interim, pending the results of the lead/lag study and NPEI obtaining the necessary, subsequent OEB approvals at the time of its next incentive rates application.

In filing its draft Rate Order, the Board directs NPEI to file detailed supporting material, including all relevant calculations showing the impact of the implementation of this Decision on its proposed revenue requirements, the allocation of the approved revenue requirement to the classes and the determination of final rates and all approved rate riders, including bill impacts. Supporting documentation shall include, but not be limited to, the filing of a completed version of the revenue requirement work form Excel spreadsheet, which can be found on the OEB’s website.

THE OEB ORDERS THAT:

1. Niagara Peninsula Energy Inc. shall file with the OEB, and serve on registered intervenors, a draft Rate Order attaching a proposed Tariff of Rates and Charges and supporting documents reflecting the Board’s findings in this Decision, along with a draft Accounting Order within 7 days of the date of the issuance of this Decision.

2. Registered intervenors and OEB staff shall file any comments on the draft Rate Order with the OEB and serve them on all other registered parties within 5 days of the date of filing of the draft Rate Order.

3. Niagara Peninsula Energy Inc. shall file with the OEB and serve on registered intervenors responses to any comments on its draft Rate Order within 3 days of the date of receipt of intervenor and OEB staff’s comments.

COST AWARDS

1. Intervenors shall file with the OEB and forward to Niagara Peninsula Energy Inc. their respective cost claims within 7 days from the date of issuance of the final Rate Order.

2. Niagara Peninsula Energy Inc. shall file with the OEB and forward to intervenors any objections to the claimed costs within 17 days from the date of issuance of the final Rate Order.

3. Intervenors shall file with the OEB and forward to Niagara Peninsula Energy Inc. any responses to any objections for cost claims within 21 days of the date of the final Rate Order.

4. Niagara Peninsula Energy Inc. shall pay the OEB's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote the file number, **EB-2014-0096**, be made through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

DATED at Toronto, May 14, 2015

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

SETTLEMENT AGREEMENT

NIAGARA PENINSULA ENERGY INC.

BOARD FILE NO. EB-2014-0096

DATED: May 14, 2015

AIRD & BERLIS LLP
Barristers and Solicitors

Scott Stoll
Direct: 416.865.4703
E-mail: sstoll@airdberlis.com

March 25, 2015

VIA COURIER, EMAIL AND RESS

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

Dear Ms. Walli:

Re: Niagara Peninsula Energy Inc. 2015 Cost of Service Rate Application
Board File No. EB-2014-0096

We are counsel to the Applicant, Niagara Peninsula Energy Inc. ("**NPEI**") in the above noted matter.

Pursuant to the Panel's request at the oral hearing that took place on March 17, 2015, please find enclosed NPEI's Amended Proposed Partial Settlement Agreement dated March 24, 2015. This version was circulated to all parties.

The Amended Proposed Partial Settlement Agreement includes the following:

- Issue 1.2 – Deferral and Variance Account – Language was inserted to address inconsistency identified by Board Staff and to make it consistent with the Draft Order included later in the agreement.
- Issue 3.3.1 – Residential Crossover – Language was inserted to reflect consumption point of 711kWh where the crossover of benefit occurs as provided in the response to the Undertaking J1.1.
- Issue 5.1 – NPC Assets – Additional language as discussed regarding Z-Factor was inserted.

If there are any questions, please contact the undersigned.

Yours very truly,

AIRD & BERLIS LLP

Scott Stoll

SAS/bm

cc: Case Manager, Christie Clark *(via email)*
Case Manager, Richard Battista *(via email)*
Board Counsel, Maureen Helt *(via email)*
Intervenors *(via email)*

Encl.

22163136.1

EB-2014-0096

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 Niagara Peninsula Energy Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2015

AMENDED SETTLEMENT PROPOSAL
MARCH 24, 2015

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Niagara Peninsula Energy Inc.

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NIAGARA PENINSULA ENERGY INC.

EB-2014-0096

AMENDED SETTLEMENT PROPOSAL

INTRODUCTION

Niagara Peninsula Energy Inc. ("**NPEI**") filed an application with the Ontario Energy board (the "**Board**") on September 23, 2014 for the 2015 Cost of Service ("**COS**") rate application (the "**Application**") with rates to be implemented effective May 1, 2015. The Board assigned the Application file number EB-2014-0096. On October 22, 2014 the Board issued a Letter of Direction directing NPEI to serve and publish the Notice of Application and Hearing.

On November 18, 2014 the Board issued Procedural Order No. 1 granting intervenor status and cost eligibility to Energy Probe Research Foundation ("**Energy Probe**"), the Vulnerable Energy Consumers Coalition ("**VECC**") and School Energy Coalition ("**SEC**"). Procedural Order No. 1 provided dates for written interrogatories, a technical conference and a settlement conference.

The settlement conference was duly convened on February 3, 2015 and continued on February 4, 2015 in accordance with the Board's *Rules of Practice and Procedure* (the "**Rules**") and the Board's *Settlement Conference Guidelines* (the "**Settlement Guidelines**") with partial settlement as detailed and explained herein. Mr. Chris Haussmann acted as facilitator for the settlement conference.

Energy Probe, VECC and SEC (collectively herein the "**Intervenors**") participated in the settlement conference. The Intervenors along with NPEI are called the "**Parties**".

In addition to the Parties, Ontario Energy Board staff ("**Board Staff**") participated in the settlement conference. The role adopted by Board Staff is set out on page 5 of the Settlement Guidelines. Board Staff is not a Party to the Settlement Proposal, however, Board Staff that participated in the settlement conference are bound by the same requirements with respect to confidentiality and privilege as apply to the Parties to the proceeding.

This document is called a "Settlement Proposal" because it is proposed by the Parties to the Board to settle certain issues in this proceeding. It is termed a proposal as between the Parties and the Board. However, as between the Parties, and subject only to the Board's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual rights and obligations, and be binding and enforceable in accordance with its terms. As set forth later in the Preamble, this agreement is subject to a condition subsequent, that if this Settlement Proposal is not accepted by the Board in its entirety, then unless amended by the Parties it is null and void and of no further effect. In entering this agreement, the Parties understand and agree that, pursuant to the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B) (the "**Act**") the Board has the exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

For the purpose of this Settlement Proposal, the following terms have the meaning ascribed hereto:

> "**Complete Settlement**" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted, the Parties will not adduce any evidence or argument during the oral hearing in respect of these issues.
>
> "**Partial Settlement**" means an issue for which there is partial settlement, as NPEI and the Intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the Board, Parties who take any position on the issue will only adduce evidence and argument during the oral hearing on those portions of the issues not addressed in this Settlement Proposal.
>
> "**No Settlement**" means an issue for which no settlement was reached. NPEI and the Intervenors who take a position on the issue will adduce evidence and/or argument at the oral hearing on such issue.

If applicable, a Party who is noted as taking no position on an issue may or may not have participated in the discussion of that particular issue, but in either case, such Party shall take no position (a) on the settlement reached; and (b) on the sufficiency of evidence filed to date.

The settlement proceeding are subject to the rules relating to confidentiality and privilege contained in the Settlement Guidelines. The Parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to settlement – or not – of each issue during the settlement conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with the following exception – the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal.

The Settlement Proposal provides a brief description of each of the settled and partially settled issues, as applicable, together with references to the evidence. The Parties agree that references to the evidence in this Settlement Proposal shall, unless the context requires otherwise include: (a) the Application and pre-filed evidence; (b) responses to interrogatories; (c) responses to undertakings; (d) the additional information included in this Settlement Proposal and (e) the Appendices to this Settlement Proposal. The Parties agree that, for each settled and partially settled issue, as applicable, the evidence in respect of such settled or partially settled issue, as applicable, is sufficient in the context of this overall settlement to support the Settlement Proposal and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance of this Settlement Proposal by the Board.

The Appendices to this Settlement Agreement provide further support for the Settlement Proposal. The Parties acknowledge that the Appendices were prepared by NPEI. While the Intervenors have reviewed the Appendices, the Intervenors are relying upon their accurate preparation by NPEI, and the accuracy of the underlying evidence, in entering into this Settlement Proposal.

In certain situations, an appendix reflects the methodology agreed to by the Parties, and the Parties recognize that the Board's decision on a disputed issue may have an impact on such appendix. Pursuant to the Settlement Guidelines (p.3) the Parties must consider whether a settlement proposal should include an appropriate adjustment for any settled issue that may be affected by external factors. Because this is a partial settlement, to the extent that issues are inter-related, a number of the other issues may require further adjustment after the Board has rendered its decision in this proceeding. Wherever possible, these adjustments have been set out in the text of this Settlement Proposal.

The Parties have settled the issues as a package, and none of the parts of this Settlement Proposal are severable. If the Board does not accept this Settlement Proposal in its entirety, then there is no settlement unless the Parties agree that this settlement proposal may continue as a valid settlement without the inclusion of those parts that the Board does not accept.

In the event the Board directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no party will be obligated to accept any proposed revision. The Parties agree that all of the Parties who took on a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue prior to its re-submission to the Board.

Unless otherwise stated, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of the Parties to raise the same issue and/or take any position thereon in any other proceeding, whether or not NPEI is a party to such proceeding.

In this Settlement Proposal, wherever there is a reference to any item the Parties accept or agree, there shall be deemed to be included the caveat "for the purpose of settlement or partial settlement of the issues in this proceeding", and each such reference shall be read as if that phrase were included.

For ease of reference, the Settlement Proposal follows the approved Issues List dated January 29, 2015 with additional sub-issues included to capture the agreement of the Parties.

SUMMARY OF PROPOSAL

The Parties are pleased to advise the Board that they have been able to completely settle all issues in this proceeding except two: a) the percentage to be applied to compute the working capital component of Rate Base, and b) the fixed/variable rate design split for the Residential rate class.

In reaching this Settlement Proposal, the Parties have been guided by the Filing Requirements for 2015, the approved Issues List and the Report of the Board titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 ("**RRFE**").

The Parties recognize that this Application is a transition from Canadian Generally Accepted Accounting Principles (“**CGAAP**”) to Modified International Financial Reporting Standards (“**MIFRS**”). The Parties have taken these facts into consideration in developing this Settlement Proposal.

The Settlement Proposal presents a partial settlement of issues in this proceeding. The Parties, believe that, if accepted by the Board as requested, and subject to the Board’s determination with respect to the matters not settled, this Settlement Proposal will result in revenues for NPEI sufficient to allow NPEI to provide safe and reliable service to its customers, and to meet the expectations of its customers, and the Board, as outlined in the RRFE.

The Parties also believe that the agreement will narrow the issues to be heard in an oral hearing and determined by the Board. The following are the two areas of disagreement among the Parties that are proposed to go to oral hearing if this Settlement Proposal is accepted by the Board.

1. **Rate Base & Revenue Requirement (Issues: 1.1 and 2):** The Parties are not able to agree that NPEI’s use of the default 13% working capital allowance is appropriate. This has an impact on the following components of this Settlement Proposal, including Rate Base, Cost of Capital, PILs, and Revenue Requirement. The calculations throughout this Settlement Proposal have been based upon a 13% WCA. The use of 13% is not intended by the Parties to be presumptive of the Board’s decision, nor indicative of the appropriate WCA percentage. It is used as a neutral placeholder. The Parties have agreed that the final percentage and the calculations derived therefrom should be determined by the Board after an oral hearing.

2. **Rate Design (Issues: 3.4 Fixed/Variable Split Residential):** The Parties are unable to agree that the Applicant’s proposed fixed-variable split for the Residential rate class is appropriate. The Applicant has proposed an increase in the fixed charge. The calculations of rates and rate impacts throughout this Settlement Proposal have been based on the Applicant’s proposal. The use of the Applicant’s proposed fixed charge is not presumptive of the Board’s decision, nor indicative of the appropriate fixed charge. It is used as a neutral placeholder. The Parties have agreed that the residential fixed/variable split and calculations derived therefrom should be determined by the Board after an oral hearing.

1. PLANNING

1.1 <u>Capital</u>

Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

(a) customer feedback and preferences;

(b) productivity;

(c) benchmarking of costs;

(d) reliability and service quality;

(e) impact on distribution rates;

(f) trade-offs with OM&A spending;

(g) government-mandated obligations; and

(h) the objectives of the Applicant and its customers.

Complete Settlement – Capital expenditures included in Rate Base

The Parties acknowledge that NPEI has updated the 2014 projected gross capital additions as at January 29, 2015 in the amount of $14,290,332 with disposals of $633,627 for net capital additions in the amount of $13,656,705 for 2014. In addition, NPEI has updated 2014 projected depreciation to $5,584,900. The Parties accept the resulting updated 2014 ending Net Fixed Assets in the amount of $120,214,731, and as the appropriate opening balances for 2015. See Appendix 1.1-A which details the 2014 Appendix 2-BA Fixed Asset Continuity Schedule.

The Parties accept NPEI's 2015 Test Year gross capital additions in the amount of $10,871,580 and disposals in the amount of $313,581. NPEI has removed from the 2015 Test Year the capital project related to the purchase of the Niagara Parks Commission ("**NPC**") Primary Network in the amount of $818,905, and also removed $28,000 of capital expenditures related to the Other Post-Employment Benefits ("**OPEB**") allocated to capital. NPEI has also included $42,640 in the 2015 Test Year Rate Base related to paving work which was delayed from the end of 2014 to 2015 due to weather. NPEI has therefore updated depreciation expense for the 2015 Test Year for the 2014 updated projected capital additions, the removal of the NPC capital project and OPEB's allocated to capital and the inclusion of the paving work. The 2015 Test Year depreciation totals $5,034,074 after these adjustments. The Parties accept the resulting 2015 Test Year ending Net Fixed Assets in the amount of $126,052,242. See Appendix 1.1-A which details the 2015 Appendix 2-BA Fixed Asset Continuity Schedule.

The Parties therefore accept the Average Gross Fixed Assets in the amount of $246,244,429, the Average Accumulated Depreciation in the amount of $123,110,940, and the Average Net Fixed Assets in the amount of $123,133,484 to be included in the 2015 Test Year Rate Base. Please see Appendix 1.1-B-RRWF model.

Evidence: Capital included in Rate Base	
Application:	E1/T4/S1, E1/T2/S5, E1/T2/S7, E1/T3/S1, E2/T1/S1/ATT1, E2/T1/S2, E2/T1/S3, E2/T1/S1, E2/T2/S1/ATT1
Interrogatories:	IRR#1-1-Staff-1, IRR#4-1-Energy Probe-1, IRR#15-SEC#5, IRR#33-2-Staff-4 to IRR#59-2-Staff-30,

	IRR#62-2-Energy Probe-6 to 2-Energy Probe-10, IRR#69-2-Energy Probe-13 to IRR#70-2-Energy Probe-14, IRR#71-2-VECC-5 to IRR#77-2-VECC-11, IRR#81-SEC#25 to IRR#82-SEC#26, 2-Energy Probe-41TC to 2-Energy Probe-49TC, 2-VECC-51TC to 2-VECC-54TC, 7-VECC-62TC
Undertakings:	JT1.4, JT1.10, JT1.13, JT1.14
Transcript:	• page 4, line 18 to page 9 line 28 • page 38 line 17 to page 40 line 15 • page 40 line 16 to page 41 line 7 • page 41 line 8 to page 47 line 9 • Page 69 line 23 to page 72 line 23 • Page 72 line 24 to page 81 line 11 • Page 98 line 16 to page 101 line 2 • Page 101 line 24 to page 108 line 25 • Page 138 line 3 to page 139 line 19
Appendices:	Appendix 1.1-A-OEB Appendix 2-BA-2014 Fixed Asset Continuity Schedule; OEB Appendix 2-BA-2015 Fixed Asset Continuity Schedule
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

Complete Settlement - Depreciation

The Parties agree that depreciation expense of $5,034,074 is appropriate for the 2015 Test Year.

Evidence: Depreciation	
Application:	E4/T4/S1, E4/T4/S1/ATT1, E4/T4/S1/ATT2, E4/T4/S1/ATT3
Interrogatories:	IRR#4-1-Energy Probe-1, IRR#33-2-Staff-4, IRR#60-2-Energy Probe-4, IRR#61-2-Energy Probe-5, IRR#79-SEC#23, IRR#125-4-Energy Probe-32, 4-Energy Probe-57TC, 7-VECC-62TC
Undertakings:	JT1.4, JT1.7, JT1.10
Transcript:	• Page 65 line 2 to page 66 line 26
Appendices:	Appendix 1.1-A-OEB Appendix 2-BA-2015 Fixed Asset

	Continuity Schedule
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

Complete Settlement – Working Capital Allowance Base

The Parties were able to settle the appropriate components of the calculation of the Working Capital Allowance Base which incorporates the settlement of Operations, Maintenance and Administration expenses in the amount of $16,424,995 for the 2015 Test Year and the 2015 Test Year Cost of Power which incorporates the settlement of the load forecast and totals $144,149,668. All components of the Cost of Power are agreed upon. This figure includes the update to commodity pricing based on the Board's RPP Price Report November 1, 2014 to October 31, 2015 and the update to Retail Transmission Service Rates to reflect the 2015 Uniform Transmission Rates from the EB-2014-0357 Rate Order dated January 8, 2015 for Hydro One. The Parties therefore agree to the resulting Working Capital Allowance Base in the amount of $160,574,663 for the 2015 Test Year. See Appendix 1.1-C – Cost of Power for the details related to the Cost of Power calculation.

Evidence: Working Capital Allowance Base	
Application:	E3/T1/S1, E3/T2/S1, E4/T1/S1, E4/T2/S1, E4/T3/S1, E4/T3/S2, E4/T3/S3, E4/T3/S6, E4/T3/S7, E4/T3/S8
Interrogatories:	IRR#2-1-Staff-2, IRR#4-1-Energy Probe-1, IRR#5-1-Energy Probe-2, IRR#6-1-Energy Probe-3, IRR#68-2-Energy Probe-12, IRR#84-3-Staff-31 to IRR#86-3-Staff-33, IRR#89-3-Energy Probe-15 to IRR#92-3-Energy Probe-18, IRR#97-3-VECC-14, IRR#99-3-VECC-16 to IRR#104-3-VECC-21, IRR#106-3-VECC-23, IRR#109-4-Staff-36, IRR#110-4-Staff-37, IRR#111-4-Staff-38, IRR#112-4-Staff-39, IRR#113-4-Staff-40, IRR#116-4-Energy Probe-23, IRR#117-4-Energy Probe-24, IRR#119-4-Energy Probe-26, IRR#120-4-Energy Probe-27, IRR#121-4-Energy Probe-28, IRR#122-4-Energy Probe-29, IRR#124-4-Energy Probe-31, IRR#127-4-VECC-26, IRR#128-4-VECC-27, IRR#129-4-VECC-28, IRR#130-4-VECC-29, IRR#131-4-VECC-30, IRR#133-4-VECC-32, IRR#134-4-VECC-33, IRR#135-4-VECC-34, IRR#136-4-VECC-35, IRR#139-4-VECC-38, IRR#140-SEC#28, IRR#141-

	SEC#29, 4-Energy Probe-54TC, 4-Energy Probe-55TC, 4-Energy Probe-56TC, 4-Energy Probe-58TC, 4-Energy Probe-60TC, 4-VECC-58TC, 4-VECC-59TC
Undertakings:	JT1.2, JT1.3, JT1.4, JT1.5, JT1.6, JT1.7, JT1.10, JT1.12, JT1.13, JT1.14, JT1.15
Transcript:	• page 49 line 11 to page 50 line 15 • page 51 line 8 to page 62 line 28 • page 63 line 1 to page 65 line 1 • Page 66 line 27 to page 67 line 15 • Page 85 line 22 to page 87 line 24 • Page 141 line 19 to page 144 line 28
Appendices:	Appendix 1.1-A OEB Appendix 2-BA-2015 Fixed Asset Continuity Schedule, Appendix 1.1-B-Revenue Requirement Work Form (“RRWF”), Appendix 1.1-C-Cost of Power
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

No Settlement - Working Capital Allowance Percentage

The Parties were unable to agree on the appropriate percentage for the working capital allowance and therefore are unable to agree on the calculated allowance for working capital. NPEI applied for a 13% working capital allowance provided for in the Filing Requirements. The Application originally requested recovery of $20,018,027 in Allowance for Working Capital. The use of 13% is not intended by the Parties to be presumptive of the Board’s decision, nor indicative of the appropriate WCA percentage. It is used as a neutral placeholder. The Parties have agreed that the final percentage and the calculations derived therefrom should be determined by the Board after an oral hearing. This figure, has been updated to incorporate the agreed upon components of the Working Capital Allowance Base as a result of interrogatories, undertakings and settlement in the amount of $20,874,706.

The Parties have agreed to ask the Board to hear this issue of the appropriate percentage by way of an oral hearing.

NPEI has agreed that, regardless of the Board’s decision on the appropriate percentage, NPEI will undertake a lead/lag study prior to its next Cost of Service rate application, unless the Ontario Energy Board completes a generic hearing that is determinative of this issue prior to that time.

The Parties acknowledge that, if the Board determines that a percentage other than 13% is appropriate, mathematical adjustments to Allowance for Working Capital, Rate Base, Cost of Capital, PILs, and other aspect of this Settlement Proposal will be required.

Evidence: Working Capital Allowance	
Application:	E2/T1/S3
Interrogatories:	IRR#67-2-Energy Probe-11, IRR#78-2-VECC-12, IRR#83-SEC#27
Undertakings:	None
Transcript:	• Page 139 line 21 to page 141 line 12
Appendices:	Appendix 1.1-B-Revenue Requirement Work Form ("RRWF") Appendix 1.1-C-Cost of Power
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

Partial Settlement – Rate Base

NPEI originally applied for a Rate Base of $143,761,898 using the 13% Working Capital Allowance as per the Filing guidelines, and has updated its Rate Base amount as a result of interrogatories, undertakings and settlement proceedings in the amount of $144,008,190. See Appendix 1.1-B – Revenue Requirement Work Form ("RRWF") and the RRWF tracking form. Subject to the Board's determination on Working Capital Allowance Percentage, the Parties have accepted the revised proposed Rate Base for the 2015 Test Year.

The Parties acknowledge NPEI may need to recalculate the Rate Base to reflect the Board's decision on Working Capital Allowance Percentage.

Evidence: Rate Base	
Application:	E1/T2/S4, E1/T2/S6, E1/T2/S7, E1/T2/S8, E2/T1/S1/ATT1, E2/T1/S2, E2/T1/S3, E2/T1/S4, E3/T1/S1, E3/T2/S1, E4/T1/S1, E4/T2/S1, E4/T3/S1, E4/T3/S2, E4/T4/S1
Interrogatories:	IRR#1-1-Staff-1, IRR#2-1-Staff-2, IRR#4-1-Energy Probe-1, IRR#5-1-Energy Probe-2, IRR#6-1-Energy Probe-3, IRR#15-SEC#5, IRR#33-2-Staff-4 to IRR#59-2-Staff-30, IRR#62-2-Energy Probe-6, IRR#68-2-Energy Probe-12, IRR#69-2-Energy Probe-13 to IRR#70-2-Energy

	Probe-14, IRR#71-2-VECC-5 to IRR#77-2-VECC-11, IRR#81SEC#25 to IRR#82-SEC#26, IRR#84-3-Staff-31 to IRR#86-3-Staff-33, IRR#89-3-Energy Probe-15 to IRR#92-3-Energy Probe-18, IRR#97-3-VECC-14, IRR#99-3-VECC-16 to IRR#104-3-VECC-21, IRR#106-3-VECC-23, IRR#109-4-Staff-36, IRR#110-4-Staff-37, IRR#111-4-Staff-38, IRR#112-4-Staff-39, IRR#113-4-Staff-40, IRR#116-4-Energy Probe-23, IRR#117-4-Energy Probe-24, IRR#119-4-Energy Probe-26, IRR#120-4-Energy Probe-27, IRR#121-4-Energy Probe-28, IRR#122-4-Energy Probe-29, IRR#124-4-Energy Probe-31, IRR#127-4-VECC-26, IRR#128-4-VECC-27, IRR#129-4-VECC-28, IRR#130-4-VECC-29, IRR#131-4-VECC-30, IRR#133-4-VECC-32, IRR#134-4-VECC-33, IRR#135-4-VECC-34, IRR#136-4-VECC-35, IRR#139-4-VECC-38, IRR#140-SEC#28, IRR#141-SEC#29, 4-Energy Probe-41TC to 4-Energy Probe-58TC, 3-VECC-57TC, 4-VECC-58TC, 4-VECC-59TC, 4-VECC-61TC, 7-VECC-62TC
Undertakings:	JT1.2, JT1.3, JT1.4, JT1.5, JT1.6, JT1.7, JT1.10, JT1.12, JT1.13, JT1.14, JT1.15
Transcript:	• page 4, line 18 to page 9 line 28 • page 38 line 17 to page 40 line 15 • page 40 line 16 to page 41 line 7 • page 41 line 8 to page 47 line 9 • Page 69 line 23 to page 72 line 23 • Page 72 line 24 to page 81 line 11 • Page 98 line 16 to page 101 line 2 • Page 101 line 24 to page 108 line 25 • Page 138 line 3 to page 139 line 19 • page 49 line 11 to page 50 line 15 • page 51 line 8 to page 62 line 28 • page 63 line 1 to page 65 line 1 • Page 66 line 27 to page 67 line 15 • Page 85 line 22 to page 87 line 24 • Page 141 line 19 to page 144 line 28
Appendices:	Appendix 1.1-A OEB Appendix 2-BA-2015 Fixed Asset

	Continuity Schedule Appendix 1.1-B-Revenue Requirement Work Form (“RRWF”) Appendix 1.1-C-Cost of Power
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

Partial Settlement - Capital Structure and Cost of Capital

The Parties have agreed that a capital structure comprised of 4% short term debt at 2.16%; 56% long-term debt updated as a result of settlement at 3.92% and 40% equity at 9.30% return on equity is appropriate. See Appendix 1.1-D-Capital Structure and Cost of Capital for updated Appendix 2-OA and Appendix 2-OB.

The short-term debt rate, long-term debt rate used for affiliate debt and return on equity are set out in the Board’s letter of November 20, 2014. The long-term debt is a weighted average of the affiliate debt held by NPEI’s shareholder, Niagara Falls Hydro Holding Corporation and the City of Niagara Falls, at the Board’s deemed rate for affiliate debt, third party debt at the incurred rate and unfunded debt at the weighted average cost of debt. The latter is a change from the Application, which calculated the unfunded debt at the deemed rate. This change has been made to be consistent with the Board’s decisions in EB-2008-0272 and EB-2008-0235. The weighted average cost of capital is reduced from 6.23% to 6.00%.

NPEI will update the dollar amount of its Cost of Capital to reflect any changes resulting from the Board’s decision pertaining to Working Capital Allowance.

Evidence: Capital Structure and Cost of Capital	
Application:	E1/T2/S9, E5/T1/S1, E5/T2/S1
Interrogatories:	IRR#12-SEC#2, IRR#32-SEC#22, IRR#143-5-Staff-42, IRR#144-5-Energy Probe-34, IRR#145-5-Energy Probe-35, IRR#146-5-VECC-39, IRR#147-5-VECC-40
Undertakings:	JT1.11
Transcript:	• Page 92 line 7 to page 95 line 12
Appendices:	Appendix 1.1-D-OEB Appendices 2-OA & 2-OB
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

1.2 **OM&A**

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

(a) customer feedback and preferences;

(b) productivity;

(c) benchmarking of costs;

(d) reliability and service quality;

(e) impact on distribution rates;

(f) trade-offs with capital spending;

(g) government-mandated obligations; and

(h) the objectives of the Applicant and its customers.

Complete Settlement – OM&A

The Parties have been able to agree on the planned OM&A expenditures for the 2015 Test Year. NPEI is requesting $16,424,995 for OM&A be included in rates, as set out in more detail in the summary table below. This includes $287,232 in property taxes, as detailed in Section 1.2.1 below. This amount was updated from the original application to reflect the responses to interrogatories and undertakings, and then adjusted as part of the settlement. NPEI originally applied for planned OM&A expenditures in the amount of $17,041,580. The Parties have agreed to a reduction of $223,000 related to water labour billing activities, a reduction of $74,000 related to OPEB's recorded in OM&A, $19,663 related to regulatory expenses and a general reduction in the amount of $299,922 to the planned OM&A expenditures for the 2015 Test Year.

A summary table of the revised OM&A Budget is as follows:

	Original Submission COS 2015 Test Year	Interrogatory Adjustment Regulatory Expenses	Settlement Adjustments	Settled - 2015 Test Year OM&A
	$	$	$	$
Operations	4,291,150		(110,000)	4,181,150
Maintenance	2,554,924		(115,923)	2,439,001
Billing & Collection	5,609,882		(361,000)	5,248,882
Community Relations	69,600		-	69,600
Administration and General	4,516,024	(19,662)	(10,000)	4,486,362
Total OM&A	**17,041,580**	**(19,662)**	**(596,923)**	**16,424,995**

The Parties agree that the Board should establish a Deferral and Variance account to record the amount above or below $43,760, the amount in the 2015 Test Year meter reading expenses, that may be incurred as a result of the amendment to section 5.1.3 of the DSC including the following:

“For the purposes of measuring energy delivered to the customer, a distributor shall:

a) install a MIST meter on any new installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW; and

b) have until August 21, 2020 to install a MIST meter on any existing installation that has a monthly average peak demand during a calendar year of over 50 kW.” (Distribution System Code, Section 5.1.3)
The amendments to section 5.1.3 came into force on August 21, 2014.

As part of its’ capital spending NPEI is planning to complete the installation of 183 MIST meters per year between 2015 and 2019 to comply with section 5.1.3 of the DSC. As such, NPEI originally included in its application, $131,760 which was the average annual incremental increase in metering reading costs related to installing MIST meters for the period from 2015 to 2019. This amount has been reduced by $88,000 as part of the general OM&A reduction to $43,760 which represents only the incremental meter reading costs associated with the 2015 Test Year.

Evidence: OM&A	
Application:	E1/T4/S1, E1/T2/S4, E1/T2/S8, E4/T1/S1, E4/T2/S1, E4/T3/S1, E4/T3/S2, E4/T3/S3, E4/T3/S4, E4/T3/S6, E4/T3/S7, E4/T3/S8
Interrogatories:	IRR#2-1-Staff-2, IRR#4-1-Energy Probe-1, IRR#5-1-

	Energy Probe-2, IRR#6-1-Energy Probe-3, IRR#109-4-Staff-36, IRR#110-4-Staff-37, IRR#111-4-Staff-38, IRR#112-4-Staff-39, IRR#113-4-Staff-40, IRR#116-4-Energy Probe-23, IRR#117-4-Energy Probe-24, IRR#119-4-Energy Probe-26, IRR#120-4-Energy Probe-27, IRR#121-4-Energy Probe-28, IRR#122-4-Energy Probe-29, IRR#124-4-Energy Probe-31, IRR#127-4-VECC-26, IRR#128-4-VECC-27, IRR#129-4-VECC-28, IRR#130-4-VECC-29, IRR#131-4-VECC-30, IRR#133-4-VECC-32, IRR#134-4-VECC-33, IRR#135-4-VECC-34, IRR#136-4-VECC-35, IRR#139-4-VECC-38, IRR#140-SEC#28, IRR#141-SEC#29, 4-Energy Probe-54TC, 4-Energy Probe-55TC, 4-Energy Probe-56TC, 4-Energy Probe-58TC, 4-VECC-58TC, 4-VECC-59TC, 4-VECC-61TC
Undertakings:	JT1.5, JT1.6, JT1.10, JT1.12, JT1.13
Transcript:	• page 49 line 11 to page 50 line 15 • page 51 line 8 to page 62 line 28 • page 63 line 1 to page 65 line 1 • Page 66 line 27 to page 67 line 15 • Page 85 line 22 to page 87 line 24 • Page 141 line 19 to page 144 line 28
Appendices:	None
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

1.2.1 **Complete Settlement - Property Tax and LEAP**

The Parties agree that the inclusions in operating costs of $287,232 for Property Tax and $37,166 for LEAP Program funding are appropriate. NPEI calculated LEAP in accordance with the Chapter 2 Filing Requirements for Electricity Distribution Rate Applications-Cost of Service dated July 17, 2013.

Evidence: Property Tax and LEAP	
Application:	E4/T5/S7, E4/T3/S7
Interrogatories:	None
Undertakings:	None
Transcript:	None
Appendices:	Appendix 1.1-B-RRWF

Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

2. REVENUE REQUIREMENT

2.1 Are all elements of the Base Revenue Requirement reasonable?

Partial Settlement - Base Revenue Requirement

After adjustments for interrogatories, undertakings and settlement on issues achieved to reach this partial settlement, and subject to the Board's determination with respect to Working Capital Allowance Percentage, the Parties agreed to the amount of $28,665,192 as the Base Revenue Requirement. Each of the elements of the Base Revenue Requirement is dealt with separately in this Settlement Proposal.

Complete Settlement - Other Revenue

NPEI charges for certain activities whose costs are recovered through Specific Service Charges and Retailer Charges as detailed in Appendix 2.1-A-Specific Service Charges. The Parties have agreed that Other Operating Revenue in the amount of $1,602,522 is the appropriate revenue offset for the purpose of calculating Service Revenue Requirement for the 2015 Test Year The Board's Appendix 2-H Other Operating Revenue can be found in Appendix 2.1-B-Other Operating Revenue.

Evidence: Other Revenue	
Application:	E3/T1/S3
Interrogatories:	IRR#1-1-Staff-1, IRR#88-3-Staff-35, IRR#93-3-Energy Probe-19, IRR#94-3-Energy Probe-20, IRR#107-3-VECC-24, IRR#108-3-VECC-25
Undertakings:	JT1.6
Transcript:	None
Appendices:	Appendix 2.1-A Specific Service Charges Appendix 2.1-B-Other Revenue
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

2.1.1 **Partial Settlement - PILS**

The Parties agree that PILs have been properly calculated taking into account the response to the interrogatories, undertakings and settlement conference.

The Parties acknowledge that NPEI may have to recalculate the PILs amount as a result of the Board's decision regarding the Working Capital Allowance.

Evidence: PILS	
Application:	E4/T5/S1, E4/T5/S2, E4/T5/S3, E4/T5/S4, E4/T5/S5, E4/T5/S6
Interrogatories:	IRR#1-1-Staff-1, IRR#114-4-Staff-41, IRR#126-4-Energy Probe-33
Undertakings:	JT1.1, JT1.15
Transcript:	• Page 5 line 15 to page 5 line 26
Appendices:	Appendix 2.3-A-PILS Model
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

2.1.2 **Complete Settlement - Depreciation**

See Issue 1.1 and Appendix 1.1-A Fixed Asset Continuity Schedule for 2015.

Evidence: Depreciation	
Application:	E4/T4/S1, E4/T4/S1/ATT1, E4/T4/S1/ATT2, E4/T4/S1/ATT3
Interrogatories:	IRR#33-2-Staff-4, IRR#60-2-Energy Probe-4, IRR#61-2-Energy Probe-5, IRR#79-SEC#23, IRR#125-4-Energy Probe-32
Undertakings:	JT1.4, JT1.7, JT1.10
Transcript:	• Page 65 line 2 to page 66 line 26
Appendices:	Appendix 1.1-A-OEB Appendix 2-BA-2015 Fixed Asset Continuity Schedule
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

2.2 **Has the Base Revenue Requirement been accurately determined based on these elements?**

Partial Settlement - Base Revenue Requirement

See Issue 2.1.

The table below is an updated summary of bill impacts as a result of the issues agreed to as part of this Settlement Proposal.

The Parties acknowledge that, if the Board determines that a percentage other than 13% is appropriate for Working Capital Allowance, and/or the rate design fixed/variable split for the Residential rate class the summary of bill impacts will be updated by NPEI.

Monthly Bill Impacts

	Volume		2014 Distribution Charges	Proposed 2015 Distribution Charges	Total Distribution Charges only excluding Pass through		2014 Total Bill	Proposed 2015 Total Bill	Total Bill	
Customer Class	kWh	kW	$	$	$ Change	% Change	$	$	$ Change	% Change
Residential	800		29.80	31.52	$ 1.72	5.78%	129.83	135.67	$ 5.84	4.50%
GS<50 kw	2000		69.41	62.17	$ (7.24)	-10.43%	314.82	316.24	$ 1.42	0.45%
GS>50 kW	65000	180	942.78	510.10	$(432.68)	-45.89%	9,013.22	8,800.50	$(212.71)	-2.36%
USL	250		22.96	22.23	$ (0.73)	-3.16%	53.87	54.33	$ 0.46	0.86%
Sentinel	44	0.12	14.80	19.36	$ 4.56	30.84%	20.51	25.75	$ 5.24	25.55%
Streetlighting	50	0.13	1.73	1.69	$ (0.04)	-2.44%	7.97	8.14	$ 0.17	2.18%

Evidence: Base Revenue Requirement	
Application:	E1/T2/S4, E6/T1/S1
Interrogatories:	IRR#1-1-Staff-1, IRR#148-6-Energy Probe-36, 7-VECC-62TC
Undertakings:	JT1.1
Transcript:	None
Appendices:	Appendix 1.1-B-Revenue Requirement Work Form (“RRWF”)
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

3. LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

3.1 Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate? Are they an appropriate reflection of the energy and demand requirements of the applicant's customers?

Complete Settlement - Customer Forecast, load forecast, CDM and billing determinants

The Parties agree that the customer forecast, load forecast, CDM adjustment and resultant billing determinants set forth below are appropriate. For the 2015 test year, the Parties have agreed that a billed energy forecast of 1,208.063 GWh is appropriate. The Board's Appendix 2-IA, which can be found in Appendix 3.1-A, provides the agreed allocation across the various rate classes.

The Table below provides the customer / connection forecast for the 2015 Test Year.

Customer/Connection Counts

(No change from Originally Filed to After Settlement)

Class	2015 Test Year Originally Filed	2015 Test Year Filed with Interrogatories and Technical Conference	2015 Test Year Filed After Settlement
Residential	47,067	47,067	47,067
GS<50 kW	4,385	4,385	4,385
GS>50 kW	862	862	862
Unmetered Scattered Load (connections)	422	422	422
Sentinel Lights (connections)	303	303	303
Streetlighting (connections)	12,989	12,989	12,989
Totals	**66,028**	**66,028**	**66,028**

In response to Interrogatories, NPEI revised the CDM adjustments for 2013 and 2015, made a correction for the double counting of 2014 and 2015 CDM results, and updated the regression equation used to forecast the 2015 Test Year purchased energy. The table below provides the resulting 2015 weather normalized billed energy forecast by rate class.

2015 Weather Normalized Billed kWh Forecast

Class	2015 Test Year Originally Filed	2015 Test Year Filed with Interrogatories and Technical Conference	2015 Test Year Filed After Settlement
Residential	399,166,843	407,092,792	407,092,792
GS<50 kW	118,740,733	121,037,129	121,037,129
GS>50 kW	657,957,068	669,981,013	669,981,013
Unmetered Scattered Load	2,215,047	2,215,047	2,215,047
Sentinel Lights	259,459	259,459	259,459
Streetlighting	7,477,962	7,477,962	7,477,962
Totals	**1,185,817,112**	**1,208,063,402**	**1,208,063,402**

The billed kW demand forecast for the 2015 Test Year is based on a three year average ratio of kW to kWh for the classes that are billed distribution revenue on a demand basis. The table below shows the 2015 Test Year kW forecast.

2015 Billed kW Forecast

Class	2015 Test Year Originally Filed	2015 Test Year Filed with Interrogatories and Technical Conference	2015 Test Year Filed After Settlement
GS>50 kW	1,739,879	1,771,675	1,771,675
Sentinel Lights	705	705	705
Streetlighting	21,184	21,184	21,184
Totals	**1,761,769**	**1,793,564**	**1,793,564**

During the Interrogatory process, NPEI updated the CDM results that were incorporated into the weather normalized load forecasting model. The Parties agree that for the purposes of LRAMVA, the amount of CDM savings that are included in the 2015 Test Year Load Forecast is 15,433,325 kWh (on a net basis). The corresponding demand reduction for the GS>50 kW class that has been included in the 2015 Test Year Demand Forecast is 25,326 kW. The table below provides a summary of the CDM results that have been included in the 2015 Test Year forecasts.

2015 Expected CDM Savings for LRAM Variance Accounts

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2015 CDM net kWh	3,006,321	3,468,020	8,958,983	-	-	-	15,433,325
2015 CDM kW	-	-	25,326	-	-	-	25,326

Evidence: Customer Forecast, Load Forecast, CDM & Billing Determinants	
Application:	E1/T2/S6, E3/T2/S1, E3/T1/S1
Interrogatories:	IRR#84-3-Staff-31, IRR#85-3-Staff-32, IRR#86-3-Staff-33, IRR#87-3-Staff-34, IRR#88-3-Staff-35, IRR#89-3-Energy Probe-15, IRR#90-3-Energy Probe-16, IRR#91-3-Energy Probe-17, IRR#92-3-Energy Probe-18, IRR#97-3-VECC-14, IRR#99-3-VECC-16, IRR#100-3-VECC-17, IRR#101-3-VECC-18, IRR#102-3-VECC-19, IRR#103-3-VECC-20, IRR#104-3-VECC-21, IRR#106-3-VECC-23, 3-Energy Probe-50TC, 3-Energy Probe-51TC, 3-Energy Probe-52TC, 3-VECC-57TC
Undertakings:	None
Transcript:	• Page 47 line 11 to page 49 line 9 • Page 84 line 4 to page 85 line 20 • Page 95 line 13 to page 97 line 19 • Page 108 line 26 to page 109 line 17
Appendices:	Appendix 3.1-A-OEB Appendix 2-I & 2-IA CDM Load Forecast Adjustments
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

Complete Settlement – Loss Factors

The Parties agree the loss factors applied for and provided in the table below are appropriate. The loss factors are based upon a five year average of historical loss factors. The Board's Appendix 2-R Loss Factors is provided below.

Appendix 2-R – Loss Factors

		Historical Years					5-Year Average
		2009	2010	2011	2012	2013	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	0	1,271,540,803	1,273,076,225	1,267,361,420	1,256,535,574	1,013,702,804
A(2)	"Wholesale" kWh delivered to distributor (lower value)	1217543467	1,265,872,663	1,267,420,745	1,261,735,599	1,250,965,044	1,252,707,504
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	0
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	1,217,543,467	1,265,872,663	1,267,420,745	1,261,735,599	1,250,965,044	1,252,707,504
D	"Retail" kWh delivered by distributor	1,161,778,118	1,193,712,076	1,232,998,827	1,214,015,314	1,202,305,265	1,200,961,920
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	-	-	-	-	-	0
F	Net "Retail" kWh delivered by distributor = **D - E**	1,161,778,118	1,193,712,076	1,232,998,827	1,214,015,314	1,202,305,265	1,200,961,920
G	Loss Factor in Distributor's system = **C / F**	1.0480	1.0605	1.0279	1.0393	1.0405	1.0431
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.053	1.065	1.033	1.044	1.045	1.0478

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0479
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0374
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Evidence: Loss Factors	
Application:	E1/T2/S2, E8/T9/S1, E8/T9/S1/ATT1
Interrogatories:	None
Undertakings:	None
Transcript:	None

Appendices:	None
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

Complete Settlement – Transformer Allowances

The Parties agree that the transformer allowances as calculated and the rates as provided in the tables below are appropriate.

2015 Forecast Transformer Allowance

Rate Class	2015 Forecast kW for Transfomer Allowance	Transformer Allowance Rate	2015 Forecast Transfomer Allowance $
GS > 50 kW	715,373	0.60	429,224

Evidence: Transformer Allowances	
Application:	E1/T2/S2, E1/T6/S11, E8/T10/S1
Interrogatories:	None
Undertakings:	None
Transcript:	None
Appendices:	None
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

3.2 **Is the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?**

Complete Settlement - Cost Allocation & Revenue to Cost Ratios

The Parties agree that the cost allocation and adjustments to the revenue-to-cost ratios are appropriate.

The Cost Allocation Model, which is included in Excel format as Appendix 3.2-A, has been updated as per the agreed upon settlement items. Appendix 3.2-A includes an updated OEB Appendix 2-P. It may need to be modified based on the Board's decision on Working Capital Allowance Percentage.

The following table provides the agreed upon revenue-to-cost ratios, which includes moving the GS>50 kW class to 120% in the 2015 Test Year, and bringing all of the classes that are below 100% up to the same percentage, 91.65%.

Revenue-to-Cost Ratios

Class	Previously Approved Ratios Most Recent Year 2014	Status Quo Ratios	2015 Proposed Ratios	Policy Range
	%	%	%	%
Residential	85.00	80.65	91.65	85 - 115
GS < 50 kW	109.09	120.11	120.00	80 - 120
GS > 50 kW	145.83	161.63	120.00	80 - 120
Street Lighting	70.00	87.23	91.65	70 - 120
Sentinel Lighting	70.00	70.99	91.65	80 - 120
Unmetered Scattered Load (USL)	101.51	119.83	119.83	80 - 120

Evidence: Cost Allocation	
Application:	E1/T2/S10, E7/T1/S1, E7/T1/S2, E7/T1/S4, E7/T1/S3
Interrogatories:	IRR#16-SEC#6, IRR#17-SEC#7, IRR#96-3-VECC-13, IRR#149-7-Staff-43, IRR#150-7-Staff-44, IRR#152-7-Energy Probe-38, IRR#153-7-Energy Probe-39, IRR#154-7-VECC-41, IRR#156-7-VECC-43, IRR#157-7-VECC-44, IRR#158-7-VECC-45, 7-Energy Probe-59TC, 2-VECC-55TC
Undertakings:	JT1.8, JT1.15
Transcript:	• Page 67 line 16 to page 67 line 27 • Page 81 line 14 to page 84 line 3 • Page 87 line 25 to page 88 line 16
Appendices:	Appendix 3.2-A Cost Allocation Model (in Excel) OEB Appendix 2-P
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

3.3 Are the applicant's proposals for rate design appropriate?

Partial Settlement - Rate Design

Subject to Section 3.4 below, the Parties agree that with the exception of the Applicant's proposed fixed-variable split for the Residential class, the rate design is appropriate.

Evidence: Rate Design	
Application:	E1/T2/S10, E8/T11/S1, E8/T1/S1
Interrogatories:	IRR#160-8-Staff-45, IRR#162-8-VECC-47, IRR#164-8-VECC-49
Undertakings:	JT1.8, JT1.15
Transcript:	None
Appendices:	None
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

3.3.1 Are the applicant's proposals regarding its fixed/variable ratios appropriate?

Partial Settlement - Fixed/Variable ratios

The Parties are unable to agree on the fixed/variable split for the Residential class. NPEI has proposed a fixed/variable split of 65%/35% for the Residential rate class. The Parties have agreed that this should be determined by the Board after an oral hearing.

The table below provides the revised fixed/variable splits, which for all rate classes except the Residential class are based on the outcomes agreed to by all Parties. For the GS>50 kW class, all Parties have agreed that the fixed rate should be set at the Minimum System with PLCC rate from the Cost Allocation Model. For the GS<50 kW, Sentinel Lights, Streetlighting and Unmetered Scattered Load classes, the current fixed/variable split has been maintained.

FIXED / VARIABLE REVENUE SPLITS

2015 Projected Revenue at Existing Rates	**Base Revenue**	**% of Base Revenue by Class**	**Fixed Charge Revenue**	**Variable Revenue**	**Fixed %**	**Variable %**	**Fixed Charge**	**Volumetric Charge**
Residential	15,624,862	54.51%	9,070,668	6,554,194	58.05%	41.95%	$ 16.06	$ 0.0161
General Service < 50 kW	3,659,015	12.76%	1,988,703	1,670,312	54.35%	45.65%	$ 37.79	$ 0.0138
General Service > 50 kW	8,920,210	31.12%	1,857,576	7,062,635	20.82%	79.18%	$ 179.58	$ 4.2400
Unmetered Scattered Load	129,135	0.45%	98,789	30,346	76.50%	23.50%	$ 19.53	$ 0.0137
Sentinel Lighting	58,115	0.20%	46,795	11,319	80.52%	19.48%	$ 12.87	$ 16.0553
Street Lighting	273,855	0.96%	179,253	94,602	65.46%	34.54%	$ 1.15	$ 4.4657
TOTAL	**28,665,192**	**100.00%**	**13,241,783**	**15,423,409**	**46.19%**	**53.81%**		

2015 Projected Revenue at Proposed Rates	**Base Revenue**	**% of Base Revenue by Class**	**Fixed Charge Revenue**	**Variable Revenue**	**Fixed %**	**Variable %**	**Fixed Charge**	**Volumetric Charge**
Residential	17,928,848	62.55%	11,653,751	6,275,097	65.00%	35.00%	$ 20.63	$ 0.0154
General Service < 50 kW	3,655,627	12.75%	1,986,861	1,668,766	54.35%	45.65%	$ 37.76	$ 0.0138
General Service > 50 kW	6,587,012	22.98%	1,058,338	5,528,674	16.07%	83.93%	$ 102.31	$ 3.3629
Unmetered Scattered Load	129,140	0.45%	98,793	30,347	76.50%	23.50%	$ 19.53	$ 0.0137
Sentinel Lighting	76,552	0.27%	61,641	14,910	80.52%	19.48%	$ 16.95	$ 21.1488
Street Lighting	288,013	1.00%	188,520	99,493	65.46%	34.54%	$ 1.21	$ 4.6966
TOTAL	**28,665,191**	**100.00%**	**15,047,904**	**13,617,288**	**52.50%**	**47.50%**		

As an update to IRR#162 8.0-VECC-47. the updated table below provides a summary of total bill impacts for the Residential class, based on three different rate design scenarios: maintain the existing fixed/variable split of 58% fixed / 42% variable, using the 65% fixed / 35% variable split proposed by NPEI and using a fixed charge of 100%.

Residential Bill Impacts Summary

TOU May - October	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill
Usage	$ Change	% Change	$ Change	% Change	$ Change	% Change
kWh / month	Existing Fixed/Variable Split	Existing Fixed/Variable Split	65:35 split	65:35 split	100% fixed	100% fixed
100	2.91	9.02%	4.82	14.99%	14.56	45.19%
250	3.59	6.76%	5.04	9.51%	12.42	23.38%
500	4.75	5.39%	5.40	6.14%	8.87	10.08%
800	6.12	4.71%	5.84	4.50%	4.60	3.55%
1000	7.03	4.45%	6.12	3.88%	1.75	1.11%
1500	9.33	4.10%	6.84	3.01%	(5.36)	-2.36%
2000	11.63	3.91%	7.56	2.54%	(12.47)	-4.20%

TOU November - April	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill
Usage	$ Change	% Change	$ Change	% Change	$ Change	% Change
kWh / month	Existing Fixed/Variable Split	Existing Fixed/Variable Split	65:35 split	65:35 split	100% fixed	100% fixed
100	2.91	9.02%	4.82	14.97%	14.56	45.19%
250	3.59	6.76%	5.04	9.51%	12.42	23.38%
500	4.75	5.39%	5.40	6.14%	8.87	10.08%
800	6.12	4.71%	5.84	4.50%	4.60	3.55%
1000	7.03	4.45%	6.12	3.88%	1.75	1.11%
1500	9.33	4.10%	6.84	3.01%	(5.36)	-2.36%
2000	11.63	3.91%	7.56	2.54%	(12.47)	-4.20%

RPP May - October	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill
Usage	$ Change	% Change	$ Change	% Change	$ Change	% Change
kWh / month	Existing Fixed/Variable Split	Existing Fixed/Variable Split	65:35 split	65:35 split	100% fixed	100% fixed
100	2.91	9.22%	4.82	15.31%	14.56	46.21%
250	3.60	7.01%	5.04	9.82%	12.42	24.20%
500	4.74	5.61%	5.40	6.40%	8.86	10.50%
800	6.12	4.81%	5.83	4.58%	4.6	3.62%
1000	7.04	4.49%	6.12	3.90%	1.75	1.12%
1500	9.33	4.05%	6.84	2.97%	(5.36)	-2.33%
2000	11.63	3.82%	7.56	2.48%	(12.47)	-4.10%

RPP November - April	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill
Usage	$ Change	% Change	$ Change	% Change	$ Change	% Change
kWh / month	Existing Fixed/Variable Split	Existing Fixed/Variable Split	65:35 split	65:35 split	100% fixed	100% fixed
100	2.91	9.22%	4.82	15.31%	14.56	46.21%
250	3.60	7.01%	5.04	9.82%	12.42	24.20%
500	4.74	5.61%	5.40	6.40%	8.86	10.50%
800	6.12	4.93%	5.83	4.70%	4.6	3.71%
1000	7.03	4.66%	6.12	4.06%	1.75	1.16%
1500	9.33	4.16%	6.84	3.05%	(5.36)	-2.39%
2000	11.63	3.90%	7.56	2.53%	(12.47)	-4.18%

For Residential customers with an average monthly consumption greater than 711 kWh, the proposed 65% fixed / 35% variable split results in a lower total bill increase than maintaining the existing fixed / variable split.

Evidence: Fixed/Variable Splits	
Application:	E1/T2/S10, E8/T1/S1, E8/T11/S1
Interrogatories:	IRR#160-8-Staff-45, IRR#162-8-VECC-47, IRR#164-8-VECC-49
Undertakings:	None
Transcript:	None
Appendices:	None
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

3.3.2 **Is the proposed generic MicroFIT Service Charge of $5.40 per month appropriate?**

Complete Settlement – MicroFIT service charge

The Parties agree the proposed generic MicroFIT Service Charge of $5.40 per month is appropriate.

Evidence: MicroFit service charge	
Application:	E8/T2/S1
Interrogatories:	None
Undertakings:	None
Transcript:	None
Appendices:	None
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

3.4 Are the proposed Retail Transmission Service Rates appropriate?

Complete Settlement - Retail Transmission Service Rates

For the purpose of achieving partial settlement of the issues herein, the Parties agree the proposed Retail Transmission Service Rates are appropriate. NPEI updated the Uniform Transmission Rates as per the 2015 Uniform Transmission Rates from the EB-2014-0357 Rate Order dated January 8, 2015 for Hydro One. See Appendix 3.5-A-RTSR updated model, NPEI filed this model in excel.

Evidence: RTSR	
Application:	E8/T3/S1
Interrogatories:	IRR#163-8-VECC-48, 8-Energy Probe-60TC
Undertakings:	JT1.9
Transcript:	• Page 67 line 28 to page 68 line 21
Appendices:	Appendix 3.5-A-RTSR Model (in excel)
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

3.4.1 Are the proposed Wholesale Market Service Rate and the Rural or Remote Electricity Rate Protection Charge (RRRP) appropriate?

1. Wholesale Market Service Rate: $0.0044 per kWh
2. Rural or Remote Electricity Rate Protection Charge $0.0013 per kWh

Complete Settlement – Wholesale Market Service Rate & RRRP

The Parties agree that use of generic Wholesale Market Service Rate and the Rural or Remote Electricity Rate Protection Charge (RRRP) are appropriate.

Evidence: WMS and RRRP	
Application:	E8/T5/S1
Interrogatories:	None
Undertakings:	None
Transcript:	None

Appendices:	Appendix 1.1-C-Cost of Power
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

3.4.2 **Is the proposed Rate Rider for Smart Meter Entity charge of $0.79 per month effective until October 31, 2018, which is billed to the Residential and GS<50 kW rate classes, appropriate?**

Complete Settlement – Smart Metering Entity Charge

The Parties agree the Rate Rider for Smart Meter Entity charge of $0.79 per month effective until October 31, 2018, which is billed to the Residential and GS<50 kW rate classes, is appropriate.

Evidence: Smart Metering Entity Charge	
Application:	E8/T6/S1
Interrogatories:	IRR#155-7-VECC-42
Undertakings:	None
Transcript:	• Page 88 line 17 to page 91 line 5
Appendices:	Appendix 1.1-C-Cost of Power
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

4. **ACCOUNTING**

4.1 **Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?**

Complete Settlement - Accounting

The Parties accept the evidence of NPEI that all impacts of changes to accounting standards, policies, estimates and adjustments, including those arising out of the IFRS transition, have been properly identified and recorded in accordance with the Board's policies, and properly reflected in rates.

Evidence: Accounting

Application:	E1/T6/S22, E1/T4/S1, E1/T6/S15, E1/T6/S25
Interrogatories:	IRR#33-2-Staff-4, IRR#61-2-Energy Probe-5, IRR#112-4-Staff-39, IRR#113-4-Staff-40, IRR#167-9-Staff-48, IRR#168-9-Staff-49, IRR#169-9-Staff-50, IRR#170-9-Staff-51, 4-Energy Probe-58TC
Undertakings:	JT1.10, JT1.13
Transcript:	• Page 66 line 27 to page 67 line 15
Appendices:	None
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

4.2 **Are the applicant's proposal for deferral and variance accounts, including the balances in the existing accounts and their disposition, the continuation of existing accounts, and the two proposed new accounts, appropriate?**

Complete Settlement - Deferral and Variance Accounts

The Parties have agreed with the disposition of the deferral and variance accounts as summarized in the Table below. Balances of all accounts in Group 1 and Group 2 including accounts 1589 and 1592 are to be disposed of over a 12 month period. The Parties agreed upon the allocators to be used to dispose of the balance in the Group 1, Group 2, Account 1592 and Account 1576. The Parties also agreed upon the Billing determinants to be used as per the updated EDDVAR model included in Appendix 4.2-A.

This Settlement proposal includes an agreement by NPEI to set up an OPEB IFRS transition Deferral and Variance account to record a payable to customers related to OPEBs on transition to IFRS in the amount of $1,570,621. A draft accounting order with respect to that account is attached as Appendix 4.2-B.

The Parties have agreed that the 1508 IFRS transition account should be closed effective January 1, 2015.

The Parties have further agreed that Account 1576 will be repaid to customers over a 24 month period. In addition, the weighted average cost of capital updated to 6.00% has been changed as a result of interrogatories, undertakings and settlement from 6.23% in the Original application. The Parties therefore agree that the balance in Account 1576 is the amount of $6,910,688. See Appendix 4.2-A-Appendix 2-EC.

The Parties agree to a Deferral Account for incremental MIST costs as set out under Issue 1.2 above. A draft accounting order with respect to that account is attached as Appendix 4.2-C.

The Parties agree that the Board should not make a determination on the clearance of the LRAMVA in this proceeding. NPEI agrees to file a separate application to clear the LRAMVA, covering the period from 2011 to 2014, in 2015 once the 2014 OPA Final Verified results are received.

Stranded meters' expenses in the amount of $1,283,704 are to be recovered over a two year period as agreed to by the Parties.

			Rate Rider
		2015 CoS Claim	Recovery Period
LV Variance Account	1550	74,555	
Smart Metering Entity Charge Variance Account	1551	37,671	
RSVA - Wholesale Market Service Charge	1580	(912,664)	
RSVA - Retail Transmission Network Charge	1584	611,116	
RSVA - Retail Transmission Connection Charge	1586	396,308	
RSVA - Power (excluding Global Adjustment)	1588	(1,588,311)	
RSVA - Global Adjustment	1589	1,582,461	
Total of Group 1 Accounts (excluding 1589)		(1,381,324)	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	16,992	
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	6,869	
Retail Cost Variance Account - Retail	1518	138,753	
Smart Grid OM&A Deferral Account	1535	19,088	
Retail Cost Variance Account - STR	1548	178,967	
Total of Group 2 Accounts		360,669	
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(63,050)	
Total of Account 1562 and Account 1592		(63,050)	
Total Balance Allocated to each class (excluding 1589)		(1,083,705)	
Total Balance Allocated to each class from Account 1589		1,582,461	
Total Balance Allocated to each class (including 1589)		498,756	1 year
Accounting Changes Under CGAAP Balance + Return Component	1576	(6,910,688)	
Total Balance Allocated to each class for Accounts 1575 and 1576		(6,910,688)	2 years

Evidence: Deferral & Variance	
Application:	E1/T2/S11, E9/T1/S1, E9/T1/S2, E9/T1/S3, E9/T1/S4,

	E9/T3/S1, E9/T2/S2, E9/T2/S3, E9/T3/S3, E9/T3/S6, E9/T3/S7, E9/T3/S8, E9/T3/S9, E9/T3/S11, E9/T8/S12
Interrogatories:	IRR#13-SEC#3, IRR#105-3-VECC-22, IRR#112-4-Staff-39, IRR#113-4-Staff-40, IRR#137-4-VECC-36, IRR#138-4-VECC-37, IRR#165-9-Staff-46 to IRR#173-9-Staff-54, IRR#174-9-VECC-50, 3-VECC-56TC
Undertakings:	JT1.10, JT1.13
Transcript:	• page 40 line 16 to page 41 line 7 • page 84 line 4 to page 84 line 17 • Page 95 line 13 to page 97 line 19 • Page 109 line 19 to page 115 line 11
Appendices:	Appendix 4.2-A- OEB Appendix 2-EC & Updated EDDVAR model (in excel)
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

5. **OTHER**

5.1 **Is the applicant's proposal with respect to the purchase of the Niagara Parks Commission Assets appropriate from a capital-planning, service and rate-making perspective?**

Complete Settlement - NPC Assets

The Parties have agreed that NPEI should remove from the 2015 Test Year the capital project related to the purchase of the Niagara Parks Commission ("NPC") Primary Network in the amount of $818,905and $11,699 of depreciation expense in the 2015 Test Year that was related to the purchase of the NPC assets. The NPC assets were removed because the Parties were not sufficiently certain that the transaction would be completed in the 2015 Test Year. NPEI agrees that it will not apply for an ICM, or a Z-factor, during its IRM term that seeks to recover from ratepayers, directly or indirectly, any costs of, or related to, the acquisition, enhancement, refurbishment, replacement, maintenance, or operation of the NPC assets.

For greater certainty, NPEI will not apply for a Z-factor for which the primary cause is the acquisition, rehabilitation, replacement, maintenance, or condition of the Niagara Parks assets. A Z-factor for which the primary cause is an external intervening event, which impacts the Niagara Parks assets will not prevent NPEI applying for Z-factor relief. For example, if an acquired transformer fails because it was in poor condition, a Z-factor application would be excluded. If it fails because of flooding from a weather event, and not because of its poor condition, a Z-factor application would be possible, subject to the normal Z-factor requirements.

Evidence: NPC Assets

Application:	E2/T2/S2, DSP-SA55
Interrogatories:	IRR#53-2-Staff-24, IRR#64-2-Energy Probe-8, IRR#76-2-VECC-10, IRR#82-SEC#26, IRR#95-3-Energy Probe-21, IRR#98-3-VECC-15, IRR#151-7-Energy Probe-37, IRR#159-7-VECC-46, 2-Energy Probe-45TC, 2-Energy Probe-48TC, 3-Energy Proge-53TC,2-VECC-51TC, 2-VECC-62TC
Undertakings:	JT1.3, JT1.15
Transcript:	• Page 10 line 1 to page 38 line 13 • Page 69 line 23 to page 72 line 23 • Page 91 line 6 to page 92 line 6 • Page 138 line 27 to page 139 line 19
Appendices:	None
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

5.2 **Is the termination of water billing appropriately reflected in the application and the proposed revenue requirement?**

Complete Settlement – Water Billing Activities

The Parties were able to reach a complete settlement with respect to whether the termination of water billing is appropriately reflected in the Application and the Revenue Requirement. NPEI has agreed to reduce OM&A billing expenses by $223,000 as a result of interrogatories, undertakings and settlement.

Evidence: Water Billing Activities	
Application:	E1/T2/S8, E3/T3/S1, E4/T2/S1, E4/T3/S1, E4/T3/S2, E4/T3/S3, E6/T1/S1, E7/T1/S4
Interrogatories:	IRR#109-4-Staff-36, IRR#118-4-Energy Probe-25, IRR#132-4-VECC-31, IRR#142-SEC#30, 4-Energy Probe-55TC, 4-VECC-59TC
Undertakings:	JT1.6
Transcript:	• page 51 line 8 to page 62 line 28
Appendices:	None
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

5.3 **Are all aspects of the merger, including savings (between the former Niagara Falls Hydro Inc. and the former Peninsula West Utilities Ltd.) appropriately accounted for in the application and the proposed revenue requirement?**

Partial Settlement – Merger Savings

The Parties agree that, with one exception, all aspects of the merger including savings (between the former Niagara Falls Hydro Inc. and the former Peninsula West Utilities Ltd.) are appropriately accounted for in the Application and the Revenue Requirement. The Parties have not agreed that the impact of the merger on Working Capital Allowance has been appropriately reflected in the Revenue Requirement. The Parties agree that this issue is part of Issue 1.1, and should be determined by the Board after an oral hearing.

Evidence: Merger Savings	
Application:	None
Interrogatories:	IRR#11-SEC#1
Undertakings:	None
Transcript:	• Page 124 line 25 to page 127 line 28
Appendices:	None
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

Appendix 1.1-A—Updated 2014 and 2015 Fixed Asset Continuity Schedules

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard	CGAAP	Updated Jan 29th, 2015PROJECTED
Year	2014	

			Cost							Accumulated Depreciation	
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Updated Projected Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 2,691,707	$ 597,468		$ 3,289,175	-$ 2,433,512	-$ 417,940		-$ 2,851,451	$ 437,724
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1806	Land Rights	$ 1,604,396			$ 1,604,396	-$ 868,162	-$ 57,099		-$ 925,261	$ 679,136
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,637	$ -		-$ 111,637	$ 1
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 3,833,013			$ 3,833,013	-$ 701,334	-$ 76,660		-$ 777,994	$ 3,055,019
47	1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 1,519,065	$ 16,478		$ 1,535,543	-$ 212,606	-$ 36,672		-$ 249,278	$ 1,286,264
47	1815	Transformer Station Equipment > 50 kV (1716)	$ 46,955			$ 46,955	-$ 37,020	-$ 10,841		-$ 47,860	-$ 905
47	1815	Transformer Station Equipment > 50 kV (1717)	$ 610,734			$ 610,734	-$ 201,066	-$ 13,339		-$ 214,406	$ 396,328
47	1815	Transformer Station Equipment > 50 kV (1719)	$ 625,179			$ 625,179	-$ 227,914	-$ 35,747		-$ 263,660	$ 361,519
47	1820	Distribution Station Equipment <50 kV	$ 4,072,270	$ 166,900		$ 4,239,170	-$ 2,131,341	-$ 59,662		-$ 2,191,003	$ 2,048,167
47	1820	Distribution Station Equipment <50 Kv (1821)	$ 2,281,769	$ 338,097		$ 2,619,866	-$ 793,416	-$ 75,587		-$ 869,003	$ 1,750,863
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures - Wood	$ 40,535,275	$ 1,775,260		$ 42,310,535	-$ 23,356,813	-$ 421,190		-$ 23,778,003	$ 18,532,532
47	1830	Poles, Towers & Fixtures - (1831) Concrete	$ 3,038,668	$ 62,303		$ 3,100,971	-$ 1,273,545	-$ 34,203		-$ 1,307,748	$ 1,793,223
47	1835	Overhead Conductors & Devices	$ 23,335,990	$ 1,319,846		$ 24,655,836	-$ 8,694,270	-$ 278,648		-$ 8,972,918	$ 15,682,919
47	1835	Overhead Conductors & Devices (1836)	$ 2,606,710	$ 111,713		$ 2,718,424	-$ 1,135,177	-$ 213,500		-$ 1,348,676	$ 1,369,747
47	1835	Overhead Conductors & Devices (1837)	$ 2,242,028	$ 418,741		$ 2,660,769	-$ 526,796	-$ 76,729		-$ 603,525	$ 2,057,244
47	1840	Underground Conduit	$ 9,663,795	$ 1,129,330		$ 10,793,125	-$ 2,359,337	-$ 178,447		-$ 2,537,784	$ 8,255,341
47	1845	Underground Conductors & Devices	$ 64,503,462	$ 2,246,660		$ 66,750,122	-$ 37,486,296	-$ 1,697,999		-$ 39,184,294	$ 27,565,827
47	1845	Underground Conductors & Devices (1846)	$ 2,071,576	$ 139,264		$ 2,210,839	-$ 1,037,566	-$ 53,676		-$ 1,091,242	$ 1,119,597
47	1850	Line Transformers (1850) Polemount	$ 19,321,845	$ (193,868)	-$ 123,854	$ 19,004,123	-$ 13,332,426	-$ 206,717	$ 123,854	-$ 13,415,289	$ 5,588,834
47	1850	Line Transformers (1853) Padmount	$ 18,034,372	$ 1,638,266	-$ 68,643	$ 19,603,996	-$ 8,380,992	-$ 511,668	$ 68,643	-$ 8,824,017	$ 10,779,979
47	1855	Services (Overhead & Underground)	$ 5,430,061	$ 673,899		$ 6,103,960	-$ 1,310,965	-$ 230,680		-$ 1,541,644	$ 4,562,316
47	1860	Meters	$ 2,893,476	$ 535,335		$ 3,428,811	-$ 987,855	-$ 163,888		-$ 1,151,744	$ 2,277,067
47	1860	Meters (Smart Meters)	$ 4,202,487	$ 1,724,874		$ 5,927,361	-$ 975,073	-$ 467,441		-$ 1,442,514	$ 4,484,847
47	1865	Other Installations on Customer's Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1875	Street Lighting and Signal Systems	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 15,117,431	$ 1,597,103		$ 16,714,533	-$ 2,687,517	-$ 261,491		-$ 2,949,008	$ 13,765,525
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,493,564	$ 158,000		$ 1,651,565	-$ 937,619	-$ 92,048		-$ 1,029,667	$ 621,897
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,199,583	$ 275,153		$ 2,474,736	-$ 1,414,760	-$ 277,560		-$ 1,692,320	$ 782,416
10	1930	Transportation Equipment (1931)	$ 705,984	$ -		$ 705,984	-$ 363,891	-$ 68,307		-$ 432,198	$ 273,786
10	1930	Transportation Equipment (1932) Large Trucks	$ 7,544,698	$ 635,480	-$ 441,130	$ 7,739,048	-$ 3,897,852	-$ 281,521	$ 441,130	-$ 3,738,244	$ 4,000,804
10	1930	Transportation Equipment (1933) Trailers	$ 329,326	$ 20,575		$ 349,901	-$ 229,633	-$ 5,928		-$ 235,561	$ 114,341
8	1935	Stores Equipment	$ 236,414	$ 47,643		$ 284,057	-$ 202,066	-$ 6,595		-$ 208,661	$ 75,396
8	1940	Tools, Shop & Garage Equipment	$ 1,954,826	$ 67,513		$ 2,022,339	-$ 1,532,643	-$ 78,713		-$ 1,611,356	$ 410,983
8	1945	Measurement & Testing Equipment	$ 204,006	$ -		$ 204,006	-$ 194,127	-$ 7,775		-$ 186,352	$ 17,654
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ 846,784	$ 258,142		$ 1,104,926	-$ 175,400	-$ 37,409		-$ 212,809	$ 892,117
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951	$ -		$ 72,951	-$ 70,632	-$ 2,072		-$ 72,704	$ 247
47	1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 21,516,863	-$ 1,469,842		-$ 22,986,705	$ 6,303,876	$ 837,299		$ 7,141,175	-$ 15,845,530
47	2440	Deferred Revenue[5]	$ -			$ -	$ -				$ -
47	2005	2005-Property Under Capital Leases	$ -			$ -	$ -				$ -
						$ -				$ -	$ -
		Sub-Total	**$ 227,308,724**	**$ 14,290,332**	**-$ 633,627**	**$ 240,965,429**	**-$ 115,799,421**	**-$ 5,584,900**	**$ 633,627**	**-$ 120,750,694**	**$ 120,214,735**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 227,308,724**	**$ 14,290,332**	**-$ 633,627**	**$ 240,965,429**	**-$ 115,799,421**	**-$ 5,584,900**	**$ 633,627**	**-$ 120,750,694**	**$ 120,214,735**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 5,584,900**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 5,584,900

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS updated for Settlement conference
Year 2015

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Projected	Cost: Projected	Cost: Updated Projected Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 3,289,175	$ 368,740		$ 3,657,916	-$ 2,851,451	-$ 144,536		-$ 2,995,988	$ 661,928
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1806	Land Rights	$ 1,604,396			$ 1,604,396	-$ 925,261	-$ 57,034		-$ 982,295	$ 622,101
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,637	$ -		-$ 111,637	$ 1
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 3,833,013			$ 3,833,013	-$ 777,994	-$ 76,660		-$ 854,654	$ 2,978,359
47	1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 1,535,543			$ 1,535,543	-$ 249,278	-$ 36,851		-$ 286,129	$ 1,249,414
47	1815	Transformer Station Equipment > 50 kV (1716)	$ 46,955			$ 46,955	-$ 47,860	$ 905		-$ 46,955	-$ 0
47	1815	Transformer Station Equipment > 50 kV (1717)	$ 610,734			$ 610,734	-$ 214,406	-$ 13,339		-$ 227,745	$ 382,989
47	1815	Transformer Station Equipment > 50 kV (1719)	$ 625,179			$ 625,179	-$ 263,660	-$ 35,747		-$ 299,407	$ 325,772
47	1820	Distribution Station Equipment <50 kV	$ 4,239,170			$ 4,239,170	-$ 2,191,003	-$ 61,516		-$ 2,252,520	$ 1,986,650
47	1820	Distribution Station Equipment <50 Kv (1821)	$ 2,619,866			$ 2,619,866	-$ 869,003	-$ 81,222		-$ 950,226	$ 1,669,641
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures - Wood	$ 42,310,535	$ 2,191,067		$ 44,501,603	-$ 23,778,003	-$ 460,266		-$ 24,238,269	$ 20,263,334
47	1830	Poles, Towers & Fixtures - (1831) Concrete	$ 3,100,971			$ 3,100,971	-$ 1,307,748	-$ 35,212		-$ 1,342,960	$ 1,758,011
47	1835	Overhead Conductors & Devices	$ 24,655,836	$ 1,164,812		$ 25,820,649	-$ 8,972,918	-$ 299,353		-$ 9,272,271	$ 16,548,377
47	1835	Overhead Conductors & Devices (1836)	$ 2,718,424	$ 101,000		$ 2,819,424	-$ 1,348,676	-$ 208,937		-$ 1,557,613	$ 1,261,810
47	1835	Overhead Conductors & Devices (1837)	$ 2,660,769	$ 30,162		$ 2,690,931	-$ 603,525	-$ 84,210		-$ 687,735	$ 2,003,196
47	1840	Underground Conduit	$ 10,793,125	$ 1,327,447		$ 12,120,571	-$ 2,537,784	-$ 203,015		-$ 2,740,798	$ 9,379,773
47	1845	Underground Conductors & Devices	$ 66,750,122	$ 1,625,160		$ 68,375,282	-$ 39,184,294	-$ 1,228,322		-$ 40,412,616	$ 27,962,666
47	1845	Underground Conductors & Devices (1846)	$ 2,210,839	$ 561,196		$ 2,772,036	-$ 1,091,242	-$ 61,092		-$ 1,152,334	$ 1,619,702
47	1850	Line Transformers (1850) Polemount	$ 19,004,123	$ 885,008		$ 19,889,131	-$ 13,415,289	-$ 215,357		-$ 13,630,646	$ 6,258,485
47	1850	Line Transformers (1853) Padmount	$ 19,603,996	$ 662,260		$ 20,266,256	-$ 8,824,017	-$ 547,748		-$ 9,371,765	$ 10,894,491
47	1855	Services (Overhead & Underground)	$ 6,103,960	$ 1,018,443		$ 7,122,403	-$ 1,541,644	-$ 264,526		-$ 1,806,171	$ 5,316,232
47	1860	Meters	$ 3,428,811	$ 284,541		$ 3,713,352	-$ 1,151,744	-$ 184,385		-$ 1,336,129	$ 2,377,223
47	1860	Meters (Smart Meters)	$ 5,927,361	$ 143,150		$ 6,070,511	-$ 1,442,514	-$ 409,581		-$ 1,852,095	$ 4,218,415
47	1865	Other Installations on Customer's Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1875	Street Lighting and Signal Systems	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 16,714,533	$ 86,640		$ 16,801,173	-$ 2,949,008	-$ 283,873		-$ 3,232,881	$ 13,568,293
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,651,565	$ 32,824		$ 1,684,388	-$ 1,029,667	-$ 110,019		-$ 1,139,686	$ 544,702
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,474,736	$ 240,248		$ 2,714,984	-$ 1,692,320	-$ 272,863		-$ 1,965,183	$ 749,801
10	1930	Transportation Equipment (1931)	$ 705,984	$ 114,086	-$ 63,099	$ 756,970	-$ 432,198	-$ 65,721	$ 63,099	-$ 434,819	$ 322,151
10	1930	Transportation Equipment (1932) Large Trucks	$ 7,739,048	$ 513,992	-$ 250,482	$ 8,002,558	-$ 3,738,244	-$ 341,100	$ 250,482	-$ 3,828,862	$ 4,173,696
10	1930	Transportation Equipment (1933) Trailers	$ 349,901	$ 70,800		$ 420,701	-$ 235,561	-$ 8,382		-$ 243,943	$ 176,758
8	1935	Stores Equipment	$ 284,057	$ -		$ 284,057	-$ 208,661	-$ 9,770		-$ 218,430	$ 65,627
8	1940	Tools, Shop & Garage Equipment	$ 2,022,339	$ 60,803		$ 2,083,141	-$ 1,611,356	-$ 81,710		-$ 1,693,066	$ 390,075
8	1945	Measurement & Testing Equipment	$ 204,006	$ 1,000		$ 205,006	-$ 186,352	-$ 3,433		-$ 189,785	$ 15,221
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ 1,104,926	$ 215,000		$ 1,319,926	-$ 212,809	-$ 52,272		-$ 265,082	$ 1,054,844
8	1955	Communication Equipment (Smart Meters)	$ -	$ 1,000		$ 1,000	$ -			$ -	$ 1,000
8	1960	Miscellaneous Equipment	$ 72,951	$ -		$ 72,951	-$ 72,704	-$ 258		-$ 72,962	-$ 11
47	1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 22,986,705	-$ 827,800		-$ 23,814,505	$ 7,141,175	$ 903,332		$ 8,044,508	-$ 15,769,998
47	2440	Deferred Revenue[5]	$ -			$ -	$ -				$ -
47	2005	2005-Property Under Capital Leases	$ -			$ -	$ -				$ -
						$ -				$ -	$ -
		Sub-Total	**$ 240,965,429**	**$ 10,871,580**	**-$ 313,581**	**$ 251,523,428**	**-$ 120,750,694**	**-$ 5,034,074**	**$ 313,581**	**-$ 125,471,186**	**$ 126,052,242**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 240,965,429**	**$ 10,871,580**	**-$ 313,581**	**$ 251,523,428**	**-$ 120,750,694**	**-$ 5,034,074**	**$ 313,581**	**-$ 125,471,186**	**$ 126,052,242**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 5,034,074**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 5,034,074

Appendix 1.1-B—RRWF and RRWF tracking sheet

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Version 5.00

Utility Name	Niagara Peninsula Energy Inc.
Service Territory	
Assigned EB Number	EB-2014-0096
Name and Title	Suzanne Wilson, VP Finance
Phone Number	905-353-6004
Email Address	suzanne.wilson@npei.ca

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.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

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***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Data Input (1)

		Initial Application	(2)	Adjustments	Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$247,689,793		($1,445,365)	$ 246,244,429			$246,244,429	
	Accumulated Depreciation (average)	($123,945,922)	(5)	$834,982	($123,110,940)			($123,110,940)	
	Allowance for Working Capital:								
	Controllable Expenses	$17,041,580		($616,585)	$ 16,424,995			$16,424,995	
	Cost of Power	$136,943,243		$7,206,425.71	$ 144,149,669			$144,149,669	
	Working Capital Rate (%)	13.00%	(9)		13.00%	(9)		13.00%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$28,371,080		$294,112	$28,665,192				
	Distribution Revenue at Proposed Rates	$29,374,853		($709,662)	$28,665,191				
	Other Revenue:								
	Specific Service Charges	$803,285		($0)	$803,285				
	Late Payment Charges	$361,000		$0	$361,000				
	Other Distribution Revenue	$251,187		$6,047	$257,234				
	Other Income and Deductions	$181,003		$0	$181,003				
	Total Revenue Offsets	$1,596,475	(7)	$6,047	$1,602,522				
	Operating Expenses:								
	OM+A Expenses	$16,754,348		($616,585)	$ 16,137,763		$ -	$16,137,763	
	Depreciation/Amortization	$4,936,879		$97,195	$ 5,034,074			$5,034,074	
	Property taxes	$287,232			$ 287,232			$287,232	
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($4,814,861)	(3)		($4,598,147)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$34,407			$120,121				
	Income taxes (grossed up)	$43,189			$163,430				
	Federal tax (%)	15.00%			15.00%				
	Provincial tax (%)	5.33%			11.50%				
	Income Tax Credits	($81,003)			($81,003)				
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.28%			3.92%			3.92%	
	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 (%)	0.00%							

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.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$247,689,793	($1,445,365)	$246,244,429	$ -	$246,244,429
2	Accumulated Depreciation (average)	(3)	($123,945,922)	$834,982	($123,110,940)	$ -	($123,110,940)
3	Net Fixed Assets (average)	(3)	$123,743,871	($610,383)	$123,133,488	$ -	$123,133,488
4	Allowance for Working Capital	(1)	$20,018,027	$856,679	$20,874,706	$ -	$20,874,706
5	**Total Rate Base**		$143,761,898	$246,296	$144,008,195	$ -	$144,008,195

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$17,041,580	($616,585)	$16,424,995	$ -	$16,424,995
7	Cost of Power		$136,943,243	$7,206,426	$144,149,669	$ -	$144,149,669
8	Working Capital Base		$153,984,823	$6,589,841	$160,574,664	$ -	$160,574,664
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$20,018,027	$856,679	$20,874,706	$ -	$20,874,706

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.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$29,374,853	($709,662)	$28,665,191	$ -	$28,665,191
2	Other Revenue	(1)	$1,596,475	$6,047	$1,602,522	$ -	$1,602,522
3	Total Operating Revenues		$30,971,328	($703,615)	$30,267,713	$ -	$30,267,713
	Operating Expenses:						
4	OM+A Expenses		$16,754,348	($616,585)	$16,137,763	$ -	$16,137,763
5	Depreciation/Amortization		$4,936,879	$97,195	$5,034,074	$ -	$5,034,074
6	Property taxes		$287,232	$ -	$287,232	$ -	$287,232
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$21,978,459	($519,390)	$21,459,069	$ -	$21,459,069
10	Deemed Interest Expense		$3,567,234	($279,124)	$3,288,110	$ -	$3,288,110
11	Total Expenses (lines 9 to 10)		$25,545,693	($798,514)	$24,747,179	$ -	$24,747,179
12	**Utility income before income taxes**		$5,425,635	$94,899	$5,520,534	$ -	$5,520,534
13	Income taxes (grossed-up)		$43,189	$120,241	$163,430	$ -	$163,430
14	**Utility net income**		$5,382,446	($25,342)	$5,357,104	$ -	$5,357,104

Notes

Other Revenues / Revenue Offsets

		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$803,285	($0)	$803,285		$803,285
	Late Payment Charges	$361,000	$ -	$361,000		$361,000
	Other Distribution Revenue	$251,187	$6,047	$257,234		$257,234
	Other Income and Deductions	$181,003	$ -	$181,003		$181,003
	Total Revenue Offsets	$1,596,475	$6,047	$1,602,522	$ -	$1,602,522

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$5,382,445	$5,357,105	$5,357,105
2	Adjustments required to arrive at taxable utility income	($4,814,861)	($4,598,147)	($4,814,861)
3	Taxable income	$567,584	$758,958	$542,244
	Calculation of Utility income Taxes			
4	Income taxes	$34,407	$120,121	$120,121
6	Total taxes	$34,407	$120,121	$120,121
7	Gross-up of Income Taxes	$8,782	$43,309	$43,309
8	Grossed-up Income Taxes	$43,189	$163,430	$163,430
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$43,189	$163,430	$163,430
10	Other tax Credits	($81,003)	($81,003)	($81,003)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	5.33%	11.50%	11.50%
13	Total tax rate (%)	20.33%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$80,506,663	4.28%	$3,445,899
2	Short-term Debt	4.00%	$5,750,476	2.11%	$121,335
3	**Total Debt**	60.00%	$86,257,139	4.14%	$3,567,234
	Equity				
4	Common Equity	40.00%	$57,504,759	9.36%	$5,382,445
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$57,504,759	9.36%	$5,382,445
7	**Total**	100.00%	$143,761,898	6.23%	$8,949,680
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$80,644,589	3.92%	$3,163,687
2	Short-term Debt	4.00%	$5,760,328	2.16%	$124,423
3	**Total Debt**	60.00%	$86,404,917	3.81%	$3,288,110
	Equity				
4	Common Equity	40.00%	$57,603,278	9.30%	$5,357,105
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$57,603,278	9.30%	$5,357,105
7	**Total**	100.00%	$144,008,195	6.00%	$8,645,215
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$80,644,589	3.92%	$3,163,687
9	Short-term Debt	4.00%	$5,760,328	2.16%	$124,423
10	**Total Debt**	60.00%	$86,404,917	3.81%	$3,288,110
	Equity				
11	Common Equity	40.00%	$57,603,278	9.30%	$5,357,105
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$57,603,278	9.30%	$5,357,105
14	**Total**	100.00%	$144,008,195	6.00%	$8,645,215

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,003,772		($0)		($0)
2	Distribution Revenue	$28,371,080	$28,371,081	$28,665,192	$28,665,191	$28,665,192	$28,665,191
3	Other Operating Revenue Offsets - net	$1,596,475	$1,596,475	$1,602,522	$1,602,522	$1,602,522	$1,602,522
4	**Total Revenue**	$29,967,555	$30,971,328	$30,267,714	$30,267,713	$30,267,714	$30,267,713
5	Operating Expenses	$21,978,459	$21,978,459	$21,459,069	$21,459,069	$21,459,069	$21,459,069
6	Deemed Interest Expense	$3,567,234	$3,567,234	$3,288,110	$3,288,110	$3,288,110	$3,288,110
8	**Total Cost and Expenses**	$25,545,693	$25,545,693	$24,747,179	$24,747,179	$24,747,179	$24,747,179
9	**Utility Income Before Income Taxes**	$4,421,862	$5,425,635	$5,520,535	$5,520,534	$5,520,535	$5,520,534
10	Tax Adjustments to Accounting Income per 2013 PILs model	($4,814,861)	($4,814,861)	($4,598,147)	($4,598,147)	($4,598,147)	($4,598,147)
11	**Taxable Income**	($392,999)	$610,774	$922,388	$922,387	$922,388	$922,387
12	Income Tax Rate	20.33%	20.33%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	($79,911)	$124,192	$244,433	$244,433	$244,433	$244,433
14	**Income Tax Credits**	($81,003)	($81,003)	($81,003)	($81,003)	($81,003)	($81,003)
15	**Utility Net Income**	$4,582,775	$5,382,446	$5,357,105	$5,357,104	$5,357,105	$5,357,104
16	**Utility Rate Base**	$143,761,898	$143,761,898	$144,008,195	$144,008,195	$144,008,195	$144,008,195
17	Deemed Equity Portion of Rate Base	$57,504,759	$57,504,759	$57,603,278	$57,603,278	$57,603,278	$57,603,278
18	Income/(Equity Portion of Rate Base)	7.97%	9.36%	9.30%	9.30%	9.30%	9.30%
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	-1.39%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.67%	6.23%	6.00%	6.00%	6.00%	6.00%
22	Requested Rate of Return on Rate Base	6.23%	6.23%	6.00%	6.00%	6.00%	6.00%
23	Deficiency/Sufficiency in Rate of Return	-0.56%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Target Return on Equity	$5,382,445	$5,382,445	$5,357,105	$5,357,105	$5,357,105	$5,357,105
25	Revenue Deficiency/(Sufficiency)	$799,670	$0	($0)	($1)	($0)	($1)
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,003,772 **(1)**		($0) **(1)**		($0) **(1)**	

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$16,754,348		$16,137,763		$16,137,763	
2	Amortization/Depreciation	$4,936,879		$5,034,074		$5,034,074	
3	Property Taxes	$287,232		$287,232		$287,232	
5	Income Taxes (Grossed up)	$43,189		$163,430		$163,430	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$3,567,234		$3,288,110		$3,288,110	
	Return on Deemed Equity	$5,382,445		$5,357,105		$5,357,105	
8	**Service Revenue Requirement (before Revenues)**	$30,971,328		$30,267,714		$30,267,714	
9	Revenue Offsets	$1,596,475		$1,602,522		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$29,374,853		$28,665,192		$30,267,714	
11	Distribution revenue	$29,374,853		$28,665,191		$28,665,191	
12	Other revenue	$1,596,475		$1,602,522		$1,602,522	
13	**Total revenue**	$30,971,328		$30,267,713		$30,267,713	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	**(1)**	($1)	**(1)**	($1)	**(1)**

Notes

(1) Line 11 - Line 8

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Tracking Form

The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)
Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.
(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)
(2) Short description of change, issue, etc.

60 Tracking Rows have been provided below. If you require more, please contact Industry Relations @ IndustryRelations@ontarioenergyboard.ca.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 8,949,680	6.23%	$ 143,761,898	$ 153,984,823	$ 20,018,027	$ 4,936,879	$ 43,189	$ 16,754,348	$ 30,971,328	$ 1,596,475	$ 29,374,853	$ 1,003,772
1														

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Tracking Form

The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	**Item / Description [2]**	**Regulated Return on Capital**	**Regulated Rate of Return**	**Rate Base**	**Working Capital**	**Working Capital Allowance ($)**	**Amortization / Depreciation**	**Taxes/PILs**	**OM&A**	**Service Revenue Requirement**	**Other Revenues**	**Base Revenue Requirement**	**Grossed up Revenue Deficiency / Sufficiency**
		Original Application	$ 8,949,680	6.23%	$ 143,761,898	$ 153,984,823	$ 20,018,027	$ 4,936,879	$ 43,189	$ 16,754,348	$ 30,971,328	$ 1,596,475	$ 29,374,853	$ 1,003,773
1	1-EP-2	Correct amortization period of regulatory costs to 5 years	$ 8,949,306	6.23%	$ 143,759,342	$ 153,965,160	$ 20,015,471	$ 4,936,879	$ 43,156	$ 16,734,685	$ 30,951,258	$ 1,596,475	$ 29,354,783	$ 983,703
		Change	-$ 374	0.00%	-$ 2,556	-$ 19,663	-$ 2,556	$ -	-$ 33	-$ 19,663	-$ 20,070	$ -	-$ 20,070	-$ 20,070
2	8-VECC-48	Update RTSR Model for proposed 2015 UTRs	$ 8,950,011	6.23%	$ 143,770,651	$ 154,052,148	$ 20,026,779	$ 4,936,879	$ 43,300	$ 16,734,685	$ 30,952,107	$ 1,596,475	$ 29,355,632	$ 984,552
		Change	$ 705	$ -	$ 11,309	$ 86,988	$ 11,308	$ -	$ 144	$ -	$ 849	$ -	$ 849	$ 849
3	3-EP-12	Update COP for Oct 2014 RPP Report	$ 8,986,700	6.23%	$ 144,360,019	$ 158,585,748	$ 20,616,147	$ 4,936,879	$ 50,787	$ 16,734,685	$ 30,996,285	$ 1,596,475	$ 29,399,809	$ 1,028,729
		Change	$ 36,689	$ -	$ 589,368	$ 4,533,600	$ 589,368	$ -	$ 7,487	$ -	$ 44,178	$ -	$ 44,177	$ 44,177
4	3-EP-20, 3-VECC-24	Update SSS Admin Revenue	$ 8,986,700	6.23%	$ 144,360,019	$ 158,585,748	$ 20,616,147	$ 4,936,879	$ 50,787	$ 16,734,685	$ 30,996,285	$ 1,602,522	$ 29,393,762	$ 1,022,682
		Change	-$ 0	$ -	$ 0	$ -	$ -	$ -	-$ 0	$ -	$ -	$ 6,047	-$ 6,047	-$ 6,047
5	3-VECC-16, 3-VECC-17, 3-VECC-18	Update CDM for 2013 final verified. Update 2015 CDM target. Correct double counting of CDM variable in regression model	$ 9,008,080	6.23%	$ 144,703,471	$ 161,227,692	$ 20,959,600	$ 4,936,879	$ 55,165	$ 16,734,685	$ 31,022,042	$ 1,602,522	$ 29,419,520	$ 754,328
		Change	$ 21,380	$ -	$ 343,452	$ 2,641,944	$ 343,453	$ -	$ 4,378	$ -	$ 25,757	$ -	$ 25,758	-$ 268,354
6	5-EP-34	Update 2015 Cost of Capital Parameters	$ 8,862,798	6.12%	$ 144,703,471	$ 161,227,692	$ 20,959,600	$ 4,936,879	$ 43,366	$ 16,734,685	$ 30,864,961	$ 1,602,522	$ 29,262,439	$ 597,247
		Change	-$ 145,282	-$ 0	$ -	$ -	$ -	$ -	-$ 11,799	$ -	-$ 157,081	$ -	-$ 157,081	-$ 157,081
7	4-Staff-41	Update 2015 PILs to reflect elimination of Small Business Deduction	$ 8,862,798	6.12%	$ 144,703,471	$ 161,227,692	$ 20,959,600	$ 4,936,879	$ 94,620	$ 16,734,685	$ 30,916,215	$ 1,602,522	$ 29,313,693	$ 648,501
		Change	-$ 0	$ -	$ 0	-$ 0	-$ 0	$ -	$ 51,254	$ -	$ 51,254	-$ 0	$ 51,254	$ 51,254
8	2-EP-41TC	Correct PILs Model to include ($827,800) of 2015 Capital Contributions	$ 8,862,798	6.12%	$ 144,703,471	$ 161,227,692	$ 20,959,600	$ 4,936,879	$ 106,559	$ 16,734,685	$ 30,928,154	$ 1,602,522	$ 29,325,632	$ 660,440
		Change	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,939	$ -	$ 11,939	$ -	$ 11,939	$ 11,939
9	2-EP-41TC	Update 2014 and 2015 capital expenditures for projections and carry forwards.	$ 8,886,494	6.12%	$ 145,090,356	$ 161,227,692	$ 20,959,600	$ 5,094,111	$ 220,565	$ 16,734,685	$ 31,223,089	$ 1,602,522	$ 29,620,567	$ 955,375
		Change	$ 23,696	-$ 0	$ 386,885	$ 0	$ 0	$ 157,232	$ 114,006	$ -	$ 294,935	$ 0	$ 294,935	$ 294,935
10	8-EP-60TC	Update RTSR model for 2015 UTR rates approved on Jan 8, 2015.	$ 8,886,047	6.12%	$ 145,083,062	$ 161,171,587	$ 20,952,306	$ 5,094,111	$ 220,468	$ 16,734,685	$ 31,222,544	$ 1,602,522	$ 29,620,022	$ 954,830
		Change	-$ 447	$ -	-$ 7,294	-$ 56,105	-$ 7,294	$ -	-$ 97	$ -	-$ 545	$ -	-$ 545	-$ 545
11	Settlement Proposal	Adjust notional debt rate. Correct PILs CCA calculation. Update for 2014 projected capital. Remove NPC capital costs. Reduce OM&A by $297K.	$ 8,648,388	6.00%	$ 144,061,040	$ 160,874,587	$ 20,913,696	$ 5,034,354	$ 163,836	$ 16,437,685	$ 30,571,496	$ 1,602,522	$ 28,968,974	$ 303,782
		Change	-$ 237,659	-0.12%	-$ 1,022,022	-$ 297,000	-$ 38,610	-$ 59,757	-$ 56,632	-$ 297,000	-$ 651,048	$ -	-$ 651,048	-$ 651,048
12	Settlement Proposal	Remove $28K OPEB capital. Reduce OM&A by $300K.	$ 8,645,215	6.00%	$ 144,008,190	$ 160,574,663	$ 20,874,706	$ 5,034,074	$ 163,430	$ 16,137,763	$ 30,267,714	$ 1,602,522	$ 28,665,192	$ -
		Change	-$ 3,173	$ -	-$ 52,850	-$ 299,924	-$ 38,990	-$ 280	-$ 406	-$ 299,923	-$ 303,782	$ -	-$ 303,782	-$ 303,782

Appendix 1.1-C—Cost of Power

Niagara Penisula Energy Inc. (ED-2007-0749)

2015 EDR Application (EB-2014-0096)

February 23, 2015

Electricity (Commodity)	**Customer**	**Revenue**	**Expense**	**2015**	*rate ($/kWh):*	$ 0.09528
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4006	4705	426,602,336		40,646,671
kWh	General Service < 50 kW	4010	4705	126,837,721		12,085,098
kWh	General Service > 50	4035	4705	702,089,231		66,895,062
kWh	Unmetered Scattered Load	4010	4705	2,321,201		221,164
kWh	Sentinel Lighting	4030	4705	271,893		25,906
kWh	Street Lighting	4025	4705	7,836,336		746,646
	TOTAL	0	0	**1,265,958,719**		**120,620,547**
Transmission - Network	**Customer**	**Revenue**	**Expense**		**2015**	
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**
kWh	Residential	4066	4714	426,602,336	$ 0.0076	3,223,310
kWh	General Service < 50 kW	4066	4714	126,837,721	$ 0.0068	866,460
kW	General Service > 50	4066	4714	1,771,675	$ 2.8172	4,991,100
kWh	Unmetered Scattered Load	4066	4714	2,321,201	$ 0.0068	15,857
kW	Sentinel Lighting	4066	4714	705	$ 2.0858	1,471
kW	Street Lighting	4066	4714	21,184	$ 2.1297	45,116
	TOTAL	0	0	**557,554,823**		**9,143,312**
Transmission - Connection	**Customer**	**Revenue**	**Expense**		**2015**	
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**
kWh	Residential	4068	4716	426,602,336	$ 0.0053	2,248,559
kWh	General Service < 50 kW	4068	4716	126,837,721	$ 0.0046	588,318
kW	General Service > 50	4068	4716	1,771,675	$ 1.8413	3,262,222
kWh	Unmetered Scattered Load	4068	4716	2,321,201	$ 0.0046	10,767
kW	Sentinel Lighting	4068	4716	705	$ 1.5386	1,085
kW	Street Lighting	4068	4716	21,184	$ 1.4147	29,969
	TOTAL	0	0	**557,554,823**		**6,140,919**
Wholesale Market Service	**Customer**	**Revenue**	**Expense**	**2015**	*rate ($/kWh):*	$ 0.00440
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4062	4708	426,602,336	$ 0.0044	1,877,050
kWh	General Service < 50 kW	4062	4708	126,837,721	$ 0.0044	558,086
kWh	General Service > 50	4062	4708	702,089,231	$ 0.0044	3,089,193
kWh	Unmetered Scattered Load	4062	4708	2,321,201	$ 0.0044	10,213
kWh	Sentinel Lighting	4062	4708	271,893	$ 0.0044	1,196
kWh	Street Lighting	4062	4708	7,836,336	$ 0.0044	34,480
	TOTAL	0	0	**1,265,958,719**		**5,570,218**
Rural Rate Protection	**Customer**	**Revenue**	**Expense**	**2015**	*rate ($/kWh):*	$ 0.00130
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4062	4708	426,602,336	$ 0.00130	554,583
kWh	General Service < 50 kW	4062	4708	126,837,721	$ 0.00130	164,889
kWh	General Service > 50	4062	4708	702,089,231	$ 0.00130	912,716
kWh	Unmetered Scattered Load	4062	4708	2,321,201	$ 0.00130	3,018
kWh	Sentinel Lighting	4062	4708	271,893	$ 0.00130	353
kWh	Street Lighting	4062	4708	7,836,336	$ 0.00130	10,187
	TOTAL	0	0	**1,265,958,719**		**1,645,746**
Low Voltage Charges	**Customer**	**Revenue**	**Expense**		**2015**	0
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**
kWh	Residential	4075	4750	407,092,792	0.0005	203,546
kWh	General Service < 50 kW	4075	4750	121,037,129	0.0004	48,415
kW	General Service > 50	4075	4750	1,771,675	0.1612	285,594
kWh	Unmetered Scattered Load	4075	4750	2,215,047	0.0004	886
kW	Sentinel Lighting	4075	4750	705	0.1347	95
kW	Street Lighting	4075	4750	21,184	0.1239	2,625
	TOTAL	0	0	**532,138,532**		**541,161**
0	**Customer**	**Revenue**	**Expense**	**2015**		0.79
Smart Metering Entity	**Class Name**	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4076	4751	407,092,792	47,067	446,191
kWh	General Service < 50 kW	4076	4751	121,037,129	4,385	41,574
kWh	General Service > 50	4076	4751	669,981,013		0
kWh	Unmetered Scattered Load	4076	4751	2,215,047		0
kWh	Sentinel Lighting	4076	4751	259,459		0
kWh	Street Lighting	4076	4751	7,477,962		0
	TOTAL	0	0	**1,208,063,402**		**487,765**
GRAND TOTAL		0	0	**0**		**144,149,669**

Appendix 1.1-D—Capital Structure and Cost of Capital

File Number:	EB-2014-0096
Exhibit:	5
Tab:	1
Schedule:	1
Page:	1
Date:	23-Feb-15

Appendix 2-OA
Capital Structure and Cost of Capital UPDATED

This table must be completed for the last Board approved year and the test year.

Year: 2015

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$80,644,586	3.92%	$3,163,687
2	Short-term Debt	4.00%	(1)	$5,760,328	2.16%	$124,423
3	**Total Debt**	60.0%		$86,404,914	3.81%	$3,288,110
	Equity					
4	Common Equity	40.00%		$57,603,276	9.30%	$5,357,105
5	Preferred Shares	0.00%		$ -		$ -
6	**Total Equity**	40.0%		$57,603,276	9.30%	$5,357,105
7	**Total**	100.0%		$144,008,190	6.00%	$8,645,215

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

Year: 2011 Board Approved

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$66,964,502	5.16%	$3,452,039
2	Short-term Debt	4.00%	(1)	$4,783,179	2.46%	$117,666
3	**Total Debt**	60.0%		$71,747,680	4.98%	$3,569,705
	Equity					
4	Common Equity	40.00%		$47,831,787	9.58%	$4,582,285
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$47,831,787	9.58%	$4,582,285
7	**Total**	100.0%		$119,579,467	6.82%	$8,151,990

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

File Number:	EB-2014-0096
Exhibit:	5
Tab:	1
Schedule:	1
Page:	2
Date:	23-Feb-15

Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2009 This is 2010

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0725	$ 1,595,000	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0725	$ 261,369	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 4,237,226	0.0644	$ 248,408	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 8,703,329	0.0458	$ 383,217	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 4,500,000	0.0497	$ 81,384	Per amortization schedule
12									$ -	
Total							$ 43,045,645	0.0597	$ 2,569,378	

Year 2009 This is 2011 BOARD APPROVED

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0532	$ 1,170,400	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0532	$ 191,791	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 3,398,502	0.0644	$ 192,771	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 7,965,243	0.0458	$ 348,793	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 4,143,643	0.0497	$ 215,605	Per amortization schedule
6									$ -	
Total							$ 41,112,478	0.0516	$ 2,119,360	

Year 2009 This is 2011 ACTUAL

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0725	$ 1,595,000	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0725	$ 261,369	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 2,951,322	0.0644	$ 192,771	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 7,578,939	0.0458	$ 348,692	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 4,180,500	0.0497	$ 207,786	Per amortization schedule
12									$ -	
Total							$ 40,315,851	0.0646	$ 2,605,618	

Year 2012

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.058	$ 1,276,550	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0582	$ 209,740	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 2,027,297	0.0644	$ 133,443	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 6,788,719	0.0458	$ 313,473	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 3,712,500	0.0497	$ 186,416	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 135,781	Interest only repayments
Total							$ 48,133,606	0.0469	$ 2,255,403	

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0532	$ 1,170,400	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0532	$ 191,791	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 1,041,976	0.0644	$ 70,180	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 5,961,538	0.0458	$ 274,771	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 3,262,500	0.0497	$ 162,554	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 288,035	Interest only repayments
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-13	5	$ 10,000,000	0.02933	$ 14,465	Interest only repayments
Total							$ 55,871,104	0.0389	$ 2,172,196	

Year 2014 BRIDGE YEAR

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0532	$ 1,170,400	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0532	$ 191,791	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 223,632	0.0644	$ 10,065	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 5,095,208	0.0458	$ 235,175	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 2,812,500	0.0497	$ 140,680	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 280,000	Interest only repayments
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-13	5	$ 10,000,000	0.02933	$ 293,300	Interest only repayments
7	Term Loan payable-NEW	To be Determined	Third-Party	Fixed Rate	30-Nov-14	5	$ 849,315	0.02663	$ 35,020	Updated for 48 days O/S vs 31 days
Total							$ 54,585,745	0.0432	$ 2,356,431	

Year 2015 TEST YEAR

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.04806	$ 1,057,356	4 months @4.88% 8mths @ 4.77%
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.04806	$ 173,267	4 months @4.88% 8mths @ 4.77%
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 4,188,358	0.0458	$ 193,728	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ -	0.0497	$ 90,905	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 280,000	Interest only repayments
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-13	5	$ 10,000,000	0.02933	$ 293,300	Interest only repayments
7	Term Loan payable-NEW	To be Determined	Third-Party	Fixed Rate	30-Nov-14	5	$ 10,000,000	0.02663	$ 266,300	Interest only repayments
Total							$ 59,793,448	0.0394	$ 2,354,856	

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any subsequent update issued by the Board.

3 Add more lines above row 12 if necessary.

Year 2015 Deemed Interest Calculation

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0477	$ 1,049,400	Updated for 2014 parameters
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0477	$ 171,963	Updated for 2014 parameters
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 4,188,358	0.0458	$ 193,728	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ -	0.0497	$ 90,905	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 280,000	Interest only repayments
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-13	5	$ 10,000,000	0.02933	$ 293,300	Interest only repayments
7	Term Loan payable-NEW	To be Determined	Third-Party	Fixed Rate	30-Nov-14	5	$ 10,000,000	0.02663	$ 266,300	Interest only repayments
Total							$ 59,793,448	0.03923	$ 2,345,596	
				Remaining subject to deemed interest			$ 20,851,139	0.03923	$ 818,091	
							$ 80,644,586	0.03923	$ 3,163,687	

Year 2015 Deemed Interest Calculation with Notional debt removed

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0477	$ 1,049,400	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0477	$ 171,963	
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 4,188,358	0.0458	$ 193,728	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ -	0.0497	$ 90,905	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 280,000	Interest only repayments
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-13	5	$ 10,000,000	0.02933	$ 293,300	Interest only repayments
7	Term Loan payable-NEW	To be Determined	Third-Party	Fixed Rate	30-Nov-14	5	$ 10,000,000	0.02663	$ 266,300	Interest only repayments
Total							$ 59,793,448	0.0392	$ 2,345,596	
				Remaining subject to deemed interest			$ -	0	$ -	
							$ 59,793,448	0.03923	$ 2,345,596	

Appendix 2.1-A—Specific Service Charges

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Returned cheque (plus bank charges)	$	20.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary Service – Install & remove – underground – no transformer	$	300.00
Temporary Service Install & Remove – Overhead – With Transformer	$	1,000.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

Appendix 2.1-B—Other Operating Revenue

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2011 Board Approved Restated	2011 Actual	2012 Actual	2013 Actual²	Bridge Year³	Test Year
		2011	2011	2012	2013	2014	2015
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS
4305	**Regulatory Debit**	$ -	$ -	$ -	($3,054,566)	($3,333,862)	$ -
	Other Revenue						
4235	**Specific Service Charges**	$ 924,416	$ 874,868	$ 794,766	$ 810,536	$ 620,261	$ 803,285
4225	**Late Payment Charges**	$ 381,550	$ 419,155	$ 372,203	$ 353,574	$ 357,661	$ 361,000
4080-01	**MicroFit Charges**	$ -	$ 4,486	$ 11,087	$ 16,187	$ 20,542	$ 21,060
4082	**Retail Services Revenues**	$ 80,749	$ 68,150	$ 49,123	$ 44,006	$ 44,318	$ 44,424
4084	**Service Transaction Requests (STR) Revenues**	$ 2,970	$ 1,898	$ 1,323	$ 1,071	$ 1,024	$ 1,047
4086	**SSS Administration Revenue**	$ 126,094	$ 132,759	$ 138,433	$ 142,218	$ 145,406	$ 146,703
4215	**Other Utility Operating Income**	$ 32,416	$ 43,664	$ 42,683	$ 48,359	$ 43,100	$ 44,000
4355	**Gain on Disposition of Utility and Other Property**	$ -	$ 16,397	$ 359	$ 11,121	$ -	$ -
4360	**Loss on Disposition of Utility and Other Property**	$ -	$ -	$ -	($1,135)	$ -	$ -
4362	**Loss on Retirement of Utility & Other Property**	$ -	$ -	$ -	($66,865)	$ -	$ -
4375	**Revenue from Non-Utility Operations**	$ 550,885	$ 1,334,964	$ 1,825,918	$ 2,018,308	$ 1,632,123	$ -
4380	**Expenses from Non-Utility Operations**	($260,000)	($1,136,686)	($1,482,009)	(1,871,114)	-$ 1,606,051	0
4390	**Miscellaneous Non-Operating Income**	$ 40,000	$ 58,882	$ 118,923	$ 118,062	$ 111,027	$ 81,003
4405	**Interest and Dividend Income including Carrying Charges**	$ 127,863	$ 140,673	$ 174,715	$ 180,173	$ 307,684	$ 157,000
		$ 2,006,943	$ 1,959,211	$ 2,047,525	$ 1,804,502	$ 1,677,093	$ 1,659,522
	Less Carrying Charges in 4405	(45,195)	(55,431)	(54,350)	(63,298)	(187,684)	(57,000)
	Total Miscellaneous Revenue	$ 1,961,748	$ 1,903,780	$ 1,993,175	$ 1,741,204	$ 1,489,409	$ 1,602,522
Summary							
Specific Service Charges		$ 924,416	$ 874,868	$ 794,766	$ 810,536	$ 620,261	$ 803,285
Late Payment Charges		$ 381,550	$ 419,155	$ 372,203	$ 353,574	$ 357,661	$ 361,000
Other Operating Revenues		$ 242,229	$ 250,957	$ 242,649	$ 251,841	$ 254,389	$ 257,234
Other Income or Deductions Excluding Carrying Charges		$ 413,553	$ 358,799	$ 583,556	$ 325,252	$ 257,099	$ 181,003
Total		**$ 1,961,748**	**$ 1,903,780**	**$ 1,993,175**	**$ 1,741,204**	**$ 1,489,409**	**$ 1,602,522**

Appendix 2.3-A—Updated PILS model

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Version **3.0**

Utility Name	Niagara Peninsula Energy Inc.
Assigned EB Number	EB-2014-0096
Name and Title	Suzanne Wilson, VP Finance
Phone Number	905-353-6004
Email Address	Suzanne.wilson@npei.ca
Date	9/23/2014
Last COS Re-based Year	**2011**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

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.

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Rate Base			**$ 144,008,190**	

Return on Ratebase

Deemed ShortTerm Debt %	4.00%	T	$ 5,760,328	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$ 80,644,586	*X = S * U*
Deemed Equity %	40.00%	V	$ 57,603,276	*Y = S * V*
Short Term Interest Rate	2.16%	Z	$ 124,423	*AC = W * Z*
Long Term Interest	3.92%	AA	$ 3,163,687	*AD = X * AA*
Return on Equity (Regulatory Income)	9.30%	AB	**$ 5,357,105**	*AE = Y * AB*
Return on Rate Base			**$ 8,645,215**	*AF = AC + AD + AE*

Questions that must be answered

	Historical	Bridge	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	Yes	Yes
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	Yes	Yes	Yes
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Tax Rates Federal & Provincial As of June 20, 2012	Effective ################	Effective ################	Effective ################	Effective ################	Effective ################
Federal income tax					
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business					
Federal small business threshold	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	0
Federal small business rate	11.00%	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%	0.00%

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year
1	Distribution System - post 1987	56,259,372		56,259,372
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	0		0
2	Distribution System - pre 1988	3,633,291		3,633,291
8	General Office/Stores Equip	1,666,790		1,666,790
10	Computer Hardware/ Vehicles	2,705,841		2,705,841
10.1	Certain Automobiles			0
12	Computer Software	57,371		57,371
13_1	Lease # 1			0
13_2	Lease #2			0
13_3	Lease # 3			0
13_4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	282,408		282,408
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04	2,832		2,832
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	48,060,734		48,060,734
50	Data Network Infrastructure Equipment - post Mar 2007	364,650		364,650
52	Computer Hardware and system software			0
95	CWIP			0
3	Buildings acquired before 1988	1,275,277		1,275,277
1b	Buildings > 18-03-07	4,969,771		4,969,771
1b	Buildings > 18-03-07	2,425,531		2,425,531
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	121,703,868	0	121,703,868

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filer

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**1,050,008**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**1,050,008**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**1,050,008**
Current Year Deduction		**1,050,008**	**x 7% =**	**73,501**
Cumulative Eligible Capital - Closing Balance				**976,507**

Ontario Energy Board

Income Tax/PILs Workform for 2

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**0**	**0**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 7-1 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historical			0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historical			0

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	**A**	3,187,387		3,187,387
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	5,321,041		5,321,041
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121			0
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126			0
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
Previous years apprenticeship tax credit claimed	294	106,351		106,351
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
Change in Employee Future Benefits		107,944		107,944

Change in Regulatory variance accounts		879,966		879,966
Inducement - ITA 12(1)(x)-ITC from apprenticeship job creation expenditures		12,572		12,572
				0
				0
				0
				0
				0
				0
				0
Total Additions		**6,427,874**	**0**	**6,427,874**
Deductions:				
Gain on disposal of assets per financial statements	401			0
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	8,552,056		8,552,056
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	73,501		73,501
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
Apprenticeship credits included in FS income		118,062		118,062
				0
				0
				0
				0
				0
				0
Total Deductions		**8,743,619**	**0**	**8,743,619**
Net Income for Tax Purposes		**871,642**	**0**	**871,642**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**871,642**	**0**	**871,642**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

						Wires Only	
Regulatory Taxable Income						$ 871,642	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 100,239	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction (negative)	-7.00%	**E**	-$ 35,000	**F = D * E**		
Ontario Income tax						$ 65,239	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			7.48%	**K = J / A**		
	Federal tax rate (Maximum 15%)			15.00%	**L**		
	Combined tax rate					22.48%	**M = K + L**
Total Income Taxes						**$ 195,985**	N = A * M
Investment Tax Credits						$ 8,909	**O**
Miscellaneous Tax Credits						$ 109,153	**P**
Total Tax Credits						**$ 118,062**	Q = O + P
Corporate PILs/Income Tax Provision for Historical Year						**$ 77,923**	R = N - Q

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historical Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 56,259,372			$ 56,259,372	$ -	$ 56,259,372	4%	$ 2,250,375	$ 54,008,997
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 3,633,291			$ 3,633,291	$ -	$ 3,633,291	6%	$ 217,997	$ 3,415,294
8	General Office/Stores Equip	$ 1,666,790	$ 526,500		$ 2,193,290	$ 263,250	$ 1,930,040	20%	$ 386,008	$ 1,807,282
10	Computer Hardware/ Vehicles	$ 2,705,841	$ 672,000	$ -	$ 3,377,841	$ 336,000	$ 3,041,841	30%	$ 912,552	$ 2,465,289
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 57,371	$ 652,966		$ 710,337	$ 326,483	$ 383,854	100%	$ 383,854	$ 326,483
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 282,408			$ 282,408	$ -	$ 282,408	8%	$ 22,593	$ 259,815
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 2,832			$ 2,832	$ -	$ 2,832	45%	$ 1,274	$ 1,558
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 48,060,734	$ 10,678,726	$ -	$ 58,739,460	$ 5,339,363	$ 53,400,097	8%	$ 4,272,008	$ 54,467,452
50	Data Network Infrastructure Equipment - post Mar 2007	$ 364,650	$ 302,295		$ 666,945	$ 151,148	$ 515,798	55%	$ 283,689	$ 383,256
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
3	Buildings acquired before 1988	$ 1,275,277			$ 1,275,277	$ -	$ 1,275,277	5%	$ 63,764	$ 1,211,513
1b	Buildings > 18-03-07	$ 4,969,771	$ 1,457,845		$ 6,427,616	$ 728,923	$ 5,698,694	6%	$ 341,922	$ 6,085,694
1b	Buildings > 18-03-07	$ 2,425,531			$ 2,425,531	$ -	$ 2,425,531	6%	$ 145,532	$ 2,279,999
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 121,703,868	$ 14,290,332	$ -	$ 135,994,200	$ 7,145,166	$ 128,849,034		$ 9,281,567	$ 126,712,633

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filer

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				**976,507**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**976,507**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**976,507**
Current Year Deduction		**976,507**	**x 7% =**	**68,356**
Cumulative Eligible Capital - Closing Balance				**908,152**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historical Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filer

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	**Total**
Actual Historical	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	0
Balance available for use in Test Year	0
Amount to be used in Bridge Year	0
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	**Total**
Actual Historical	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	**A**	3,884,895

Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	
Amortization of intangible assets	106	5,584,950
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Adjusted Taxable Income - Bridge Year

Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		8,909
Change in Employee Benefits		20,994
Previous years Ontario apprenticeship tax credits claimed		109,153
Change in regulatory variance accounts		0
Total Additions		**5,724,006**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	9,281,567
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	68,356
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		

Ontario Energy Board

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Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Apprenticeship credits included in FS income		111,027
Total Deductions		**9,460,950**
Net Income for Tax Purposes		**147,952**
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**147,952**

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Income Tax/PILs Workform for 2015 Filers

PILS Tax Provision - Bridge Year

						Wires Only	
Regulatory Taxable Income						$ 147,952	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	4.50%	**B**	$ 6,658	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**				
	Rate reduction	-7.00%	**E**	$ -	**F = D * E**		
Ontario Income tax						$ 6,658	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			4.50%	**K = J / A**		
	Federal tax rate (Maximum 15%)			11.00%	**L**		
	Combined tax rate					15.50%	**M = K + L**
Total Income Taxes						**$ 22,932**	**N = A * M**
Investment Tax Credits						$ 7,329	**O**
Miscellaneous Tax Credits						$ 103,699	**P**
Total Tax Credits						**$ 111,028**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year						**$ -**	**R = N - Q**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

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Income Tax/PILs Workform for 2015 Filers

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 54,008,997			$ 54,008,997	$ -	$ 54,008,997	4%	$ 2,160,360	$ 51,848,637
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 3,415,294			$ 3,415,294	$ -	$ 3,415,294	6%	$ 204,918	$ 3,210,376
8	General Office/Stores Equip	$ 1,807,282	310,627		$ 2,117,909	$ 155,313	$ 1,962,595	20%	$ 392,519	$ 1,725,389
10	Computer Hardware/ Vehicles	$ 2,465,289	698,878	0	$ 3,164,167	$ 349,439	$ 2,814,728	30%	$ 844,418	$ 2,319,748
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 326,483	368,740		$ 695,223	$ 184,370	$ 510,853	100%	$ 510,853	$ 184,370
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than B	$ 259,815			$ 259,815	$ -	$ 259,815	8%	$ 20,785	$ 239,030
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 1,558			$ 1,558	$ -	$ 1,558	45%	$ 701	$ 857
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 54,467,452	9,166,447		$ 63,633,899	$ 4,583,224	$ 59,050,676	8%	$ 4,724,054	$ 58,909,845
50	Data Network Infrastructure Equipment - post Mar 2007	$ 383,256	240,248		$ 623,504	$ 120,124	$ 503,380	55%	$ 276,859	$ 346,645
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
3	Buildings acquired before 1988	$ 1,211,513			$ 1,211,513	$ -	$ 1,211,513	5%	$ 60,576	$ 1,150,937
1b	Buildings > 18-03-07	$ 6,085,694			$ 6,085,694	$ -	$ 6,085,694	6%	$ 365,142	$ 5,720,553
1b	Buildings > 18-03-07	$ 2,279,999	86,640		$ 2,366,639	$ 43,320	$ 2,323,319	6%	$ 139,399	$ 2,227,240
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 126,712,633	$ 10,871,580	$ -	$ 137,584,213	$ 5,435,790	$ 132,148,423		$ 9,700,584	$ 127,883,629

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Schedule 10 CEC - Test Year

Cumulative Eligible Capital				**908,152**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**908,152**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**908,152**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**908,152**	**x 7% =**	**63,571**
Cumulative Eligible Capital - Closing Balance				**844,581**

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Income Tax/PILs Workform for 2015 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments Additions	Test Year Adjustments Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year	0		0
			0
Other Adjustments Add (+) Deduct (-)	0		0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year	0		0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year	0		0
			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Ontario Energy Board

Income Tax/PILs Workform for 2015 Fi

Taxable Income - Test Year

		Test Year Taxable Income
Net Income Before Taxes		5,357,105

	T2 S1 line #	
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	5,034,074
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		7,329
Change in Regulatory variance accounts		0
Change in Employee future benefits		101,909
Previous years Ontario apprenticeship tax credit claimed		103,699
Total Additions		**5,247,011**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	9,700,584
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	63,571
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Apprenticeship credits included in FS income		81,003
Total Deductions		**9,845,158**
NET INCOME FOR TAX PURPOSES		**758,958**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**758,958**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 758,958	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$	87,280	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**					
	Rate reduction	-11.50%	**E**	$	-	**F = D * E**		
Ontario Income tax							$ 87,280	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate				11.50%	**K = J / A**		
	Federal tax rate (Maximum 15%)				15.00%	**L**		
	Combined tax rate						26.50%	**M = K + L**
Total Income Taxes							**$ 201,124**	**N = A * M**
Investment Tax Credits							$ 6,208	**O**
Miscellaneous Tax Credits							$ 74,795	**P**
Total Tax Credits							**$ 81,003**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year							**$ 120,121**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]					73.50%	**S = 1 - M**	**$ 43,309**	**T = R / S - R**
Income Tax (grossed-up)							**$ 163,430**	**U = R + T**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Appendix 3.1-A—CDM Load Forecast

File Number:	EB-2014-0096
Exhibit:	3
Tab:	1
Schedule:	1
Page:	1
Date:	29-Aug-14

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2015)

The 2014 bridge year is the last year of the current four year (2011-2014) CDM program, and 2015 is the first year of a new six year (2015-2020) CDM program, per the Ministirial directives of March 31, 2014. Thus, with 2015, there is a need to recognize the final year of the current 2011-2014 CDM program, as well as to estimate reasonable impacts each year for the new 2015-2020 CDM program. These are combined to estimate the adjustment for CDM program impacts on the 2015 load forecast.

Appendix 2-I was developed to help determine what would be the amount of CDM savings needed in each year to cumulatively achieve the four year 2011-2014 CDM target. This then determined the amount of kWh (and with translation, kW of demand) savings that were converted in dollars balances for the LRAMVA, and also to determine the related adjustment to the load forecast to account for OPA-reported savings. Beginning for the 2015 year, it has been adjusted because of the persistence of 2011-2014 CDM programs will be an adjustment to the load forecast in addition to the estimated savings for the first year (2015) for the new 2015-2020 CDM plan.

It is assumed that the new six year (2015-2020) CDM program will work similar to the existing 2011-2014 CDM program, meaning that distributors will offer programs each year that, cumulatively over the six years (from January 1, 2015 to December 31, 2020) will cumulatively achieve the new six year CDM target. This is the approach contemplated in the Ministerial directive letters of March 31, 2014 to the Board and to the OPA. Thus, distributors will be able to offer programs on a basis so that cumulatively over the period, the impacts, including persistence, of the CDM programs will accumulate towards achieving each distributor's 2015-2020 CDM target.

With this approach, it is necessary to account for estimated savings for the last year of the current program, particularly the estimated savings for new CDM programs offered in 2014, as well as the estimated savings for new CDM programs that the distributor will offer in 2015 towards achievement of the new six year (2015-2020) CDM program. This necessitates expansion of this Appendix 2-I to deal with both the 2011-2014 and 2015-2020 CDM plans. It is expected that this approach will be updated each year.

2011-2014 CDM Program - 2014, last year of the current CDM plan

Input the 2011-2014 CDM target in Cell B21.

Input the measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 into cells B31 to E31. These results are taken from the final 2011 CDM Report issued by the OPA for that distributor in the fall of 2012.

Measured results for 2012 CDM programs for each of the years 2012 and persistence into 2013 and 2014 are input into cells C32 to E32. These results are taken from the final 2012 CDM Report issued by the OPA for that distributor in the fall of 2013.

Measured results for 2013 CDM programs for each of the years 2013 and persistence into 2014 are input into cells C33 to E33. These results are taken from the final 2013 CDM Report issued by the OPA for that distributor in the fall of 2014. Until that report is issued, the distributor should use the results from the preliminary 2013 CDM Report issued in the spring of 2014.

Based on these inputs, the residual kWh to achieve the 4 year CDM target icalculated for 2014 CDM under the assumption that the distributor will at least achieve the 2011-2014 CDM target that is currently a condition of the utility's Distribution Licence. If the distributor has met its cumulative kWh savings target by the end of 2013, the incremental savings for 2014 are assumed to be zero. Any further savings for 2014 CDM savings and any further compensation for meeting or exceeding the four-year (2011-2014) targets will be dealt with through the disposition of the 2011-2014 LRAMVA balance, which will occur in the next cost of service application filed after the final 2014 CDM Reports issued by the OPA in the fall of 2015.

		4 Year (2011-2014) kWh Target:			
		58,000,000			
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	8.67%	8.67%	8.52%	8.52%	34.38%
2012 CDM Programs	0.00%	9.68%	9.72%	9.68%	29.09%
2013 CDM Programs	0.00%	0.00%	6.35%	6.35%	12.70%
Adjustments to Prior Years resu	1.03%	5.86%	5.86%	5.86%	18.62%
2014 CDM Programs				5.22%	5.22%
Total in Year	**9.70%**	**24.21%**	**30.46%**	**35.63%**	**100.00%**
		kWh			
2011 CDM Programs	5,026,978.00	5,026,978.00	4,942,830.00	4,942,830.00	19,939,616.00
2012 CDM Programs		5,615,949.00	5,639,392.00	5,615,949.00	16,871,290.00
2013 CDM Programs			3,682,087.00	3,682,087.00	7,364,174.00
Adjustments to Prior Years resu	597,125.00	3,400,379.00	3,400,379.00	3,400,379.00	10,798,262.00
2014 CDM Programs				3,026,658.00	3,026,658.00
Total in Year	**5,624,103.00**	**14,043,306.00**	**17,664,688.00**	**20,667,903.00**	**58,000,000.00**

2015-2020 CDM Program - 2015, first year of the current CDM plan

For the first year of the new 2015-2020 CDM plan, it is assumed that each year's program will achieve an equal amount of new CDM savings. The new targets for 2015-2020 do not take into account persistence beyond the first year, but the OPA will encourage distributors to promote and implement CDM plans that will have longer term persistence of savings. This results in each year's program being about 1/6 (18.67%) of the cumulative 2015-2020 CDM target for kWh savings. A distributor may propose an alternative approach but would be expected to document in its application why it believes that its proposal is more reasonable. In its proposal, the distributor should ensure that the sum of the results for each year's CDM program from 2015 to 2020 add up to its 2015-2020 CDM target as

6 Year (2015-2020) kWh Target:							
74,440,000							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
%							
2015 CDM Programs	16.67%						16.67%
2016 CDM Programs		16.67%					16.67%
2017 CDM Programs			16.67%				16.67%
2018 CDM Programs				16.67%			16.67%
2019 CDM Programs					16.67%		16.67%
2020 CDM Programs						16.67%	16.67%
Total in Year	**16.67%**	**16.67%**	**16.67%**	**16.67%**	**16.67%**	**16.67%**	**100.00%**
kWh							
2015 CDM Programs	12,406,666.67						12,406,666.67
2016 CDM Programs		12,406,666.67					12,406,666.67
2017 CDM Programs			12,406,666.67				12,406,666.67
2018 CDM Programs				12,406,666.67			12,406,666.67
2019 CDM Programs					12,406,666.67		12,406,666.67
2020 CDM Programs						12,406,666.67	12,406,666.67
Total in Year	**12,406,666.67**	**12,406,666.67**	**12,406,666.67**	**12,406,666.67**	**12,406,666.67**	**12,406,666.67**	**74,440,000.00**

Determination of 2015 Load Forecast Adjustment

The Board has determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the Board in other 2013 and 2-14 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis. Sheet 2-I defaults to the adjustment being done on a "net" basis consistent with Board policy and practice.

From each of the 2006-2010 CDM Final Report, and the 2011, 2012 and 2013 CDM Final Reports, issued by the OPA for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2014 into cells D31 to E33. The model will calculate the cumulative savings for all programs from 2006 to 2012 and determine the "net" to "gross" factor "g".

Net-to-Gross Conversion				
Is CDM adjustment being done on a "net" or "gross" basis?				**net**
Persistence of Historical CDM programs to 2014	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**Conversion Factor ('g')**
2006-2010 CDM programs				
2011 CDM program				
2012 CDM program				
2013 CDM program				
2006 to 2013 OPA CDM programs: Persistence to 2015	0	0	0	0.00%

The default values represent the factor that each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1" from the drop-down menu for each cell, but must support its alternatives.

These factors do not mean that CDM programs are excluded, but also reflect the assumption that impacts of 2011 and 2012 programs are already implicitly reflected in the actual data for those years that are the basis for the load forecast prior to any manual CDM adjustment.

Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast

	2011	2012	2013	2014	2015	
Weight Factor for each year's CDM program impact on 2015 load forecast	**0**	**0**	**0**	**1**	**0.5**	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Full year persistence of 2011 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2011 (first year) but full year persistence impact on 2012 and 2013, and thus reflected in base forecast before the CDM adjustment.*	*Full year persistence of 2012 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2012 (first year) but full year persistence impact on 2013, and thus reflected in base forecast before the CDM adjustment.*	*Full year impact of persistence of 2013 CDM programs on 2015 load forecast, but 50% impact in base forecast (first year impact of 2013 CDM programs on 2013 load forecast, which is part of the data for the load forecast.*	*Full year impact of persistence of 2014 programs on 2015 load forecast. 2014 CDM programs not in base forecast.*	*Only 50% of 2015 CDM programs are assumed to impact the 2015 load forecast based on the "half-year" rule.*	

2011-2014 and 2015-2020 LRAMVA and 2015 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2015 load forecast is made. However, the distributor will have two associated annualized CDM impacts, one for the 2011-2014 CDM program and the second for the 2015-2020 CDM plan. In addition, the distributor needs to reflect the CDM adjustment that was explicitly factored into its 2011 load forecast in its 2011 cost of service application (assuming that it rebased in that year). this amount, and equal persistence for 2012, 2013 and 2014 is used as an offset to determine what the net balance of the 2011-2014 LRAMVA balance should be for disposition.

The Amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2014, for assessing performance against the four-year target. The base amount for 2011-2013 is 0 (zero) for 2014 Cost of Service applications, as the utility rebased prior to the 2011-2014 CDM programs, and there was no adjustment to reflect the impacts of the 2011-2014 programs on the load forecast used to determine their last cost of service-based rates.

The proposed loss factor should correspond with the loss factor calculated in Appendix 2-R

The Manual Adjustment for the 2015 Load Forecast is the amount manually subtracted from the load forecast derived from the base forecast from historical data, and is intended to reflect the further CDM savings that the distributor needs to achieve assuming that they meet 100% of the 2011-2014 CDM target that is a condition of their target.

If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner (e.g. taking into account what programs and what OPA-measured impacts were directed at specific customer classes), for both the LRAMVA and for the load forecast adjustment.

	2011	2012	2013	2014 kWh	2015	Total for 2014	Total for 2015
Amount used for CDM threshold for LRAMVA (2015)	4,942,830.00	5,615,949.00	3,682,087.00	3,026,658.00		17,267,524.00	
2011 CDM adjustment (per Board Decision in 2011 Cost of Service Application)	5,800,000.00	5,800,000.00	5,800,000.00	5,800,000.00		23,200,000.00	
Amount used for CDM threshold for LRAMVA (2015)					12,406,666.67		12,406,666.67
Manual Adjustment for 2015 Load Forecast (billed basis)	-	-	-	3,026,658.00	6,203,333.33		9,229,991.33
Proposed Loss Factor (TLF)	4.79%	Format: X.XX%					
Manual Adjustment for 2015 Load Forecast (system purchased basis)	-	-	-	3,171,634.92	6,500,473.00		9,672,107.92

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used calculate the impact of each year's program on the CDM adjustment to the 2014 load forecast.

Appendix 2-IA
Summary and Variances of Actual and Forecast Data

Replace "Rate Class #" with the appropriate rate classification.

	2011 Board Approved	2011	2012	2013	2014 Bridge	2015 Test
Residential						
# of Customers	46,900	45,996	45,871	46,274	46,669	47,067
kWh	462,790,265	418,849,931	414,592,237	412,298,278	403,803,143	407,092,792
kW						
Variance Analysis						
# of Customers	46,900	-1.93%	-2.19%	-1.33%	-0.49%	0.36%
kWh	462,790,265	-9.49%	-10.41%	-10.91%	-12.75%	-12.04%
kW	-	0.00%	0.00%	0.00%	0.00%	0.00%
General Service < 50 kW						
# of Customers	4,352	4,307	4,260	4,315	4,350	4,385
kWh	122,331,880	129,680,926	125,465,897	124,179,905	121,349,037	121,037,129
kW						
Variance Analysis						
# of Customers	4,352	-1.03%	-2.11%	-0.85%	-0.04%	0.77%
kWh	122,331,880	6.01%	2.56%	1.51%	-0.80%	-1.06%
kW	-	0.00%	0.00%	0.00%	0.00%	0.00%
General Service > 50 kW						
# of Customers	848	859	855	863	863	862
kWh	628,090,148	675,128,624	664,095,955	655,968,805	654,912,817	669,981,013
kW	1,818,411	1,793,543	1,761,221	1,721,554	1,731,829	1,771,675
Variance Analysis						
# of Customers	848	1.30%	0.83%	1.77%	1.72%	1.65%
kWh	628,090,148	7.49%	5.73%	4.44%	4.27%	6.67%
kW	1,818,411	-1.37%	-3.15%	-5.33%	-4.76%	-2.57%
Unmetered Scattered Load						
# of Connections	465	424	384	422	422	422
kWh	2,335,428	1,798,316	2,264,271	2,247,877	2,231,402	2,215,047
kW						
Variance Analysis						
# of Connections	465	-8.82%	-17.42%	-9.25%	-9.34%	-9.35%
kWh	2,335,428	-23.00%	-3.05%	-3.75%	-4.45%	-5.15%
kW	-	0.00%	0.00%	0.00%	0.00%	0.00%
Sentinel Lighting						
# of Connections	560	369	343	337	320	303
kWh	292,817	246,192	267,435	265,619	262,521	259,459
kW	809	679	721	716	713	705
Variance Analysis						
# of Connections	560	-34.11%	-38.75%	-39.82%	-42.94%	-45.89%
kWh	292,817	-15.92%	-8.67%	-9.29%	-10.35%	-11.39%
kW	809	-16.07%	-10.88%	-11.47%	-11.82%	-12.85%
Street Lighting						
# of Connections	12,408	12,540	12,507	12,702	12,845	12,989
kWh	7,467,591	7,294,838	7,329,519	7,344,781	7,411,072	7,477,962
kW	20,107	20,391	21,037	20,809	20,995	21,184
Variance Analysis						
# of Connections	12,408	1.06%	0.80%	2.37%	3.52%	4.68%
kWh	7,467,591	-2.31%	-1.85%	-1.64%	-0.76%	0.14%
kW	20,107	1.41%	4.63%	3.49%	4.42%	5.36%

Totals

Customers / Connections	65,533	64,495	64,220	64,913	65,467	66,028
kWh	1,223,308,129	1,232,998,827	1,214,015,314	1,202,305,265	1,189,969,992	1,208,063,402
kW from applicable classes	1,839,327	1,814,613	1,782,979	1,743,079	1,753,537	1,793,564

Totals - Variance

Customers / Connections	65,533	-1.58%	-2.00%	-0.95%	-0.10%	0.76%
kWh	1,223,308,129	0.79%	-0.76%	-1.72%	-2.73%	-1.25%
kW from applicable classes	1,839,327	-1.34%	-3.06%	-5.23%	-4.66%	-2.49%

Appendix 3.2-A—Cost Allocation Model (in excel)

File name: 2015_Cost_Allocation_Model_V3_2_20140626_Settlement

File Number:	EB-2014-0096
Exhibit:	7
Tab:	4
Schedule:	1
Page:	1
Date:	23-Dec-14

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 21,014,764	66.12%	$ 20,940,354	69.18%
GS < 50 kW	$ 3,602,085	11.33%	$ 3,203,396	10.58%
GS > 50 kW	$ 6,500,897	20.46%	$ 5,604,282	18.52%
Street Lighting	$ 376,122	1.18%	$ 320,851	1.06%
Sentinel Lighting	$ 145,569	0.46%	$ 89,264	0.29%
Unmetered Scattered Load (USL)	$ 141,174	0.44%	$ 109,566	0.36%
Total	$ 31,780,610	100.00%	$ 30,267,713	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E	
	Load Forecast (LF) X current approved rates	L.F. X current approved rates X (1 + d)	LF X proposed rates	Miscellaneous Revenue	Difference in Base Dx Revenue 7(D)-7(B)
Residential	$ 15,624,862	$ 15,624,862	$ 17,928,848	$ 1,262,498	$ 2,303,986
GS < 50 kW	$ 3,659,015	$ 3,659,015	$ 3,655,627	$ 188,449	-$ 3,388
GS > 50 kW	$ 8,920,210	$ 8,920,210	$ 6,587,012	$ 138,127	-$ 2,333,198
Street Lighting	$ 273,855	$ 273,855	$ 288,013	$ 6,039	$ 14,158
Sentinel Lighting	$ 58,115	$ 58,115	$ 76,552	$ 5,257	$ 18,437
Unmetered Scattered Load (USL)	$ 129,135	$ 129,135	$ 129,140	$ 2,153	$ 5
Total	$ 28,665,192	$ 28,665,192	$ 28,665,191	$ 1,602,522	-$ 1

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2014	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	85.00%	80.65	91.65	85 - 115
GS < 50 kW	109.09%	120.11	120.00	80 - 120
GS > 50 kW	145.83%	161.63	120.00	80 - 120
Street Lighting	70.00%	87.23	91.65	70 - 120
Sentinel Lighting	70.00%	70.99	91.65	80 - 120
Unmetered Scattered Load (USL)	101.51%	119.83	119.83	80 - 120

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before Rebalancing".

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2015	2016	2017	
	%	%	%	%
Residential	91.65	91.65	91.65	85 - 115
GS < 50 kW	120.00	120.00	120.00	80 - 120
GS > 50 kW	120.00	120.00	120.00	80 - 120
Street Lighting	91.65	91.65	91.65	70 - 120
Sentinel Lighting	91.65	91.65	91.65	80 - 120
Unmetered Scattered Load (USL)	119.83	119.83	119.83	80 - 120

Note

1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2015 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2016. In 2015 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2015 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Appendix 3.2-B—Sheet O.1 Revenue to Cost Summary Worksheet (from the Cost Allocation model)

EB-2014-0096

Sheet O1 Revenue to Cost Summary Worksheet - Public

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Rate Base Assets								
crev	Distribution Revenue at Existing Rates	$28,665,192	$15,624,862	$3,659,015	$8,920,210	$273,855	$58,115	$129,135
mi	Miscellaneous Revenue (mi)	$1,602,522	$1,262,498	$188,449	$138,127	$6,039	$5,257	$2,153
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$30,267,714	$16,887,360	$3,847,464	$9,058,337	$279,894	$63,371	$131,288
	Factor required to recover deficiency (1 + D)	1.0000						
	Distribution Revenue at Status Quo Rates	$28,665,192	$15,624,862	$3,659,015	$8,920,210	$273,855	$58,115	$129,135
	Miscellaneous Revenue (mi)	$1,602,522	$1,262,498	$188,449	$138,127	$6,039	$5,257	$2,153
	Total Revenue at Status Quo Rates	$30,267,713	$16,887,360	$3,847,464	$9,058,337	$279,894	$63,371	$131,288
	Expenses							
di	Distribution Costs (di)	$6,076,213	$4,018,843	$618,590	$1,299,617	$90,672	$17,907	$30,584
cu	Customer Related Costs (cu)	$5,792,820	$4,649,821	$675,876	$441,373	$3,294	$20,563	$1,892
ad	General and Administration (ad)	$4,555,962	$3,281,707	$492,679	$713,895	$39,584	$14,471	$13,625
dep	Depreciation and Amortization (dep)	$5,034,074	$3,275,023	$523,330	$1,137,742	$63,935	$12,376	$21,669
INPUT	PILs (INPUT)	$163,430	$106,032	$16,567	$37,323	$2,289	$444	$775
INT	Interest	$3,288,110	$2,133,293	$333,312	$750,915	$46,050	$8,939	$15,602
	Total Expenses	$24,910,609	$17,464,719	$2,660,353	$4,380,865	$245,824	$74,700	$84,147
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$5,357,105	$3,475,636	$543,043	$1,223,417	$75,026	$14,563	$25,419
	Revenue Requirement (includes NI)	$30,267,713	$20,940,354	$3,203,396	$5,604,282	$320,851	$89,264	$109,566
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$229,999,767	$151,033,396	$23,262,519	$50,507,950	$3,384,945	$663,701	$1,147,255
gp	General Plant - Gross	$39,645,270	$25,884,419	$4,049,658	$8,857,703	$556,478	$108,498	$188,514
accum dep	Accumulated Depreciation	($123,110,941)	($81,042,583)	($12,303,241)	($26,874,620)	($1,882,186)	($370,108)	($638,203)
co	Capital Contribution	($23,400,607)	($15,897,099)	($2,509,930)	($4,479,479)	($334,057)	($66,954)	($113,088)
	Total Net Plant	$123,133,488	$79,978,133	$12,499,006	$28,011,553	$1,725,180	$335,138	$584,478
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$144,149,669	$48,575,506	$14,442,505	$79,944,100	$892,292	$30,959	$264,306
	OM&A Expenses	$16,424,995	$11,950,372	$1,787,145	$2,454,885	$133,550	$52,942	$46,101
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$160,574,663*	*$60,525,878*	*$16,229,650*	*$82,398,985*	*$1,025,843*	*$83,901*	*$310,407*
	Working Capital	$20,874,706	$7,868,364	$2,109,854	$10,711,868	$133,360	$10,907	$40,353
	Total Rate Base	$144,008,195	$87,846,497	$14,608,861	$38,723,421	$1,858,540	$346,045	$624,831
		Rate Base Input equals Output						
	Equity Component of Rate Base	$57,603,278	$35,138,599	$5,843,544	$15,489,368	$743,416	$138,418	$249,932
	Net Income on Allocated Assets	$5,357,105	($577,359)	$1,187,111	$4,677,472	$34,070	($11,329)	$47,141
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$5,357,105	($577,359)	$1,187,111	$4,677,472	$34,070	($11,329)	$47,141
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	80.65%	120.11%	161.63%	87.23%	70.99%	119.83%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$0	($4,052,994)	$644,067	$3,454,055	($40,957)	($25,892)	$21,722
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED COST	$0	($4,052,995)	$644,067	$3,454,055	($40,957)	($25,892)	$21,722
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.30%	-1.64%	20.31%	30.20%	4.58%	-8.18%	18.86%

Appendix 3.4-A—RTRS model (in excel)

File name: 2015_RTRS Model_V4_0_20140226_Settlement

Appendix 4.2-A—Updated Appendix 2-EC-Account 1576 and EDVARR Model (in excel)

File name: 2015_EDDVAR_Continuity_Schedule_CoS_V2_4_20140718_Settlement

Appendix 2-EC
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2011 Rebasing Year	2011	2012	2013	2014	2015 Rebasing Year
Reporting Basis	CGAAP	IRM	IRM	IRM	IRM	MIFRS
	Forecast	Actual	Actual	Actual	Forecast	Forecast
					$	$
PP&E Values under former CGAAP						
Opening net PP&E - Note 1				103,982,941	108,454,734	
Net Additions - Note 4				11,439,655	13,656,705	
Net Depreciation (amounts should be negative) - Note 4				-6,967,863	-8,066,602	
Closing net PP&E (1)				108,454,734	114,044,837	
PP&E Values under revised CGAAP (Starts from 2013)						
Opening net PP&E - Note 1				103,982,941	111,509,300	
Net Additions - Note 4				11,439,655	13,656,705	
Net Depreciation (amounts should be negative) - Note 4				-3,913,296	-4,951,273	
Closing net PP&E (2)				111,509,300	120,214,733	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-3,054,567	-6,169,896	

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-	6,169,896
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	740,792
Amount included in Deferral and Variance Account Rate Rider Calculation	-	6,910,688

WACC	6.00%
# of years of rate rider disposition period	2

Appendix 4.2-B—Draft Accounting Order-OPEB’s

Draft Accounting Order

OPEB Deferral Account

NPEI shall establish the following deferral account effective January 1, 2015:

- **Account 1508 Other Regulatory Assets, Subaccount – Other Post-Employment Benefits Deferral Account**

NPEI shall establish the Other Post-Employment Benefits ("OPEB") Deferral Account to record the cumulative actuarial gains or losses with respect to NPEI's post-retirement benefits in Account 1508, Other Regulatory Assets, Sub-account OPEB Deferral Account.

Upon rebasing on a MIFRS basis, effective from 2015 to the next time NPEI's rates are rebased, the deferral account shall be adjusted as required to record changes in the cumulative actuarial gains or losses in NPEI's post-employment benefits as supported by updated actuarial valuations prepared for NPEI.

The adjustments that will be recorded in this account shall be supported by actuarial valuations when disposition of the deferral account is sought by NPEI.

No carrying charges shall be recorded in this account.

Sample Journal Entry

The following is an example of the journal entry that will be made by NPEI.

To record the unrecognized actuarial gain relating to Other Post-Employment Benefits upon transition to IFRS, the following entry will be made. (Assuming unamortized accumulated OPEB actuarial gain of $1,570,621 as of January 1, 2015)

	$	
	Dr.	Cr.
OPEB liability (balance sheet)	1,570,621	
Other Regulatory Assets account 1508:		
Subaccount OPEB Deferral Account		1,570,621

Appendix 4.2-C—Draft Accounting Order-MIST meter Deferral Account

Draft Accounting Order – MIST Meters Variance Account

NPEI shall establish the following variance account effective January 1, 2015:

- Account 1508 Other Regulatory Assets
    - Subaccount – MIST Meters Variance Account

This account shall be used to record the variance in costs above or below $43,760 which is the amount included in the 2015 Test Year meter reading expense, relating to the implementation of MIST meters between 2015 and 2019, that may be incurred as a result of the amendment to section 5.1.3 of the Distribution System Code.

Disposition of the account is proposed to occur in NPEI's next cost of service rate application and will be subject to the Board's prudence review.

No carrying charges will be recorded on this account.

Sample Journal Entry

The following is an example of the journal entry that will be made by NPEI.

The example assumes that incremental MIST meter reading costs are higher than the amount included in the 2015 Test Year by $50,000. This amount is assumed for illustration purposes only.

	$	
	Dr.	Cr.
Other Regulatory Assets account 1508:		
Subaccount MIST Meters Variance Account	50,000	
Accounts Payable		50,000