St. Thomas Energy Inc.
135 Edward St.
St. Thomas, ON
N5P 4A8

November 4, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Walli,

RE: St. Thomas Energy Inc.'s
2015 Cost of Service Electricity Distribution Rate Application;
Settlement Proposal; EB-2014-0113

Pursuant to Procedural Order No. 1 in the above-captioned matter, a Settlement Conference was convened in this proceeding on October 6, 2014 and concluded on October 7, 2014.

St. Thomas Energy Inc. ("STEI") is pleased to advise that the Parties have achieved a full settlement in this matter; accordingly, along with the attached Settlement Proposal.

Sincerely,

Robert Kent, CPA, CGA
Director of Finance and Regulatory Affairs
St. Thomas Energy Inc.
(519)-631-5550 x 5258 rkent@sttenergy.com

St. Thomas energy inc.
We're Your Local Power Distributor
a division of Ascent

EB-2014-0113

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by St. Thomas Energy Inc. to the Ontario Energy Board for an Order approving just and reasonable rates and other charges, effective January 1, 2015.

St. Thomas Energy Inc.

Settlement Proposal

Filed: November 4, 2014

Table of Contents

INTRODUCTION

St. Thomas Energy Inc. ("STEI") is owned by the Ascent Group Inc., which is wholly owned by the City of St. Thomas and is licensed as an electricity distributor by the Ontario Energy Board (Distribution License number ED 2002-0523).

STEI is responsible for the delivery of electricity from the transmission system to approximately 16,700 Residential, General Service, Street Light and Sentinel Light customers in the City of St. Thomas. STEI owns the poles, conduit systems, meters, transformers, wires and substations and is responsible for the construction, expansion, operation and maintenance of the electrical distribution system.

STEI filed an application (the "Application") with the Ontario Energy Board (the "Board" and "OEB") on April 30, 2014 under section 78 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that STEI charges for electricity distribution, to be effective January 1, 2015. The Board assigned File Number EB-2014-0113 to the Application.

The Board issued A Notice of Application and Hearing on July 7, 2014. Three Intervenors requested and were granted Intervenor status:

1. Energy Probe Research Foundation ("Energy Probe")
2. School Energy Coalition ("SEC")
3. Vulnerable Energy Consumers Coalition ("VECC")

Procedural Order No. 1 issued August 6, 2014, scheduled dates for written interrogatories from Board staff and Intervenors (August 19, 2014), STEI's interrogatory responses (September 9, 2014), a Technical Conference (September 22-23, 2014), a Settlement Conference (October 6-7, 2014) and the date on which the Settlement Proposal should be filed (October 28, 2014).

Prior to the Settlement Conference, the Board reviewed the proposed issues list and approved it on October 2, 2014 for the purpose of this proceeding.

The Intervenors, together with STEI (collectively, the "Parties"), engaged in a settlement conference, which resulted in a full settlement of the issues in this proceeding.

This document sets out the terms of that settlement.

SETTLEMENT PROCESS

The Settlement Conference was convened on October 6, 2014 in accordance with Procedural Order No. 1. The Settlement Conference concluded on October 7, 2014. The following Intervenors, in addition to STEI, participated in the Settlement Conference:

1. Energy Probe
2. SEC
3. VECC

The Parties have settled all issues on the Board's approved Issues List. The specific components of this settlement, including all evidentiary supporting references, are described in detail below on an issue-by-issue basis in the section entitled Settlement Proposal.

The role adopted by Board staff in the Settlement Conference was consistent with the guidance set out on page 5 of the Board's Practice Direction on Settlement Conferences (the "Practice Direction"). Although Board staff is not a party to this Settlement Proposal, as noted in the Practice Direction, the Board staff who participated in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Practice Direction. 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 the settlement – or not – of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal.

This document comprises the Settlement Proposal, and it is presented jointly to the Board by the Parties. This document is called a "Settlement Proposal" because it is a proposal by the Parties to the Board to settle the issues in this proceeding. It is termed a proposal 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 obligations, and binding and enforceable in accordance with its terms. As set forth later in this preamble, this agreement is subject to a condition subsequent, that if it 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 into this agreement the Parties understand and agree that, pursuant to the Act, the Board has exclusive jurisdiction with respect to the interpretation or enforcement of the terms hereof.

This Settlement Proposal provides a description of each of the settled issues, together with references to the evidence before the Board. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the responses to Interrogatories and Technical Conference Questions and Undertakings, and all other components of the record up to and including the date hereof, including additional information included by the Parties in this Settlement Proposal, and the Appendices to this document.

The supporting Parties for each settled issue agree that the evidence in respect of that issue is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate and robust evidentiary record to support acceptance by the Board of this Settlement Proposal.

There are Appendices to this Settlement Proposal that provide further support for the proposed settlement. The Parties agree that this Settlement Proposal and the Appendices form part of the record in EB-2014-0113. The Applicant prepared the Appendices. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the Applicant's accuracy and completeness in entering into this Settlement Proposal.

Outlined below are the final agreements of the Parties following the Settlement Conference. For ease of reference, this Settlement Proposal follows the format of the final approved Issues List for the Application attached to the Issue List Decision issued on October 2, 2014. The Parties explicitly request that the Board consider and accept this Settlement Proposal as a package. None of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Settlement Proposal. The distinct issues addressed in this proposal are intricately interrelated, and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this proposal that may be unacceptable to one or more of the Parties. If the Board does not accept the Settlement Proposal in its entirety, then there is no agreement unless the Parties agree in writing that the balance of this Settlement Proposal may continue as a valid settlement, subject to any revisions that may be agreed upon by the Parties.

It is further acknowledged and agreed that none of the Parties will withdraw from this agreement under any circumstances, except as provided under Rule 32.05 of the Board's *Rules of Practice and Procedure.*

In the event that 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.

Unless otherwise expressly stated in this Settlement Proposal, the agreement by the Parties to the settlement of each issue shall be interpreted as being for the purpose of settlement only and not a statement of principle applicable in any other situation. Where, if at all, the Parties have agreed that a particular principle should be applicable generally, this Settlement Proposal so states expressly. This is consistent with Board policy, under which settlements and their approval by the Board are considered to be specific to the facts of the particular case.

It is also acknowledged and agreed that this Settlement Proposal is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Settlement Proposal. However, none of the Parties will, in any subsequent proceeding, take the position that the resolution therein of any issue settled in this Settlement Proposal, if contrary to the terms of this Settlement Proposal, should be applicable to STEI for any part of the 2015 Test Year.

The Settlement Proposal is presented to the Board for its consideration and adoption as an inter-related package. That is, the Parties have agreed to the terms of settlement in their entirety and request that the Board approve it as such.

SETTLEMENT PROPOSAL OVERVIEW

RRFE & STEI's 2015 Cost of Service Application

On October 18, 2012 the Board released its Report entitled "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" ("RRFE") A central objective of the RRFE, which the Board described as "an important step in the continued evolution of electricity regulation in Ontario" is to support the cost-effective planning and operation of the electricity distribution network.

The Board emphasized that its renewed regulatory framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. *"The Board believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation. The Board has concluded that the following outcomes are appropriate for distributors: Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance."*[1] The Parties focused upon these specific outcomes throughout the Settlement Conference discussions.

The RRFE provides for the option of filing a rebasing Application, followed by four years of Price Cap IR. STEI selected the Price Cap IR approach on the basis that it is the best approach for the utility at this time to ensure that it continues to have adequate financial capacity and cash flow to manage its utility, and address investments in its system, over the next five years.

The Parties believe that the settlement of each issue as outlined in this Settlement Agreement is consistent with the RRFE. Further details are included in the section below, and under each issue.

[1] RRFE, page 2

OVERVIEW OF SETTLED ISSUES

The Parties have accepted, with some reductions, the operating and capital plan proposed by the Applicant. STEI has, in turn, accepted the principle that its investment plan will allow it to respond to the renewal of its system, while at the same time driving efficiencies in its operating costs, within the context of the Board's Price Cap IR. All of this will allow STEI to maintain and enhance its historical record as a low cost, efficient distributor of electricity to its customers.

The following is a summary of the major changes to the Application as filed. The details are contained in the body of this Settlement Proposal:

- The Parties have agreed to a reduction to the Bridge Year capital expenditures of $107,000 and to the Test Year capital expenditures of $88,000 from the amounts sought in the Application. In addition, STEI agreed to remove the fair market value adjustment related to the assets purchased from an affiliated company in 2012, to increase the contributed capital in both the Bridge and Test Years by $15,000 and to remove $422,504 in stranded meter capital from the Test year opening rate base. These changes have been reflected in the settled revenue requirement.

  For the purposes of setting rates, the Parties acknowledge that the capital expenditure agreed upon in this Settlement Proposal is an envelope amount, and that St. Thomas Energy Inc. may make its reductions as it considers appropriate.

- The Parties have agreed to a reduction of $158,760 in OM&A expenditures and to a transfer of $23,400 of costs from OM&A expenditures to account 4380, Expenses from Non-Rate Regulated Utility Operations. After review of the revised OM&A budget, all Parties agreed that the proposed OM&A provides appropriate resources to operate effectively, while providing for continuing efficiency initiatives to keep costs as low as possible. The Parties acknowledge that the OM&A Budget is a current forecast, and the inclusion of that budget in this Settlement Proposal is not intended to detract from the normal principle that utility management makes operating decisions within the overall envelope, in light of conditions and priorities at the time, and is not restricted to the amounts in the sub-categories included in the approved budget.

  The STEI revised OM&A budget is provided in Settlement Table 1 under Issue 1.1.

- The Parties have agreed that the net Other Revenues budget should be increased by $1,600. Specifically, the Other Revenues have been increased by $25,000 to reflect a notional allocation of 25% of postage costs to its billing partner. The $25,000 increase is then offset by the $23,400 of cost transferred from OM&A expenditures to account 4380, Expenses from Non-Rate Regulated Utility Operations referred to above.

- The parties have agreed to recognize the assets transferred to STEI from its affiliate on January 1, 2012 at their Net Book Value as opposed to their Fair Market Value as originally proposed in the Application.

Following the adjustments made as a result of this Settlement Proposal, the total bill impact for a typical Residential Class Customer consuming 800 kWh per month would be an increase of $0.35 or 0.31%. In addition, the bill impact for typical General Service < 50 kW Class Customer consuming 2,000 kWh per month would be a decrease of $1.50 or 0.57%.

The Parties believe that, if accepted by the Board as the Parties request, this Settlement Proposal will also achieve the following outcomes in the Test Year:

Customer Focus

This Settlement Proposal will respond to the primary concerns of STEI's customers, which are rates and reliability. This Settlement Proposal ensures that STEI will continue to have sufficient resources to invest in its system to optimize the performance of its assets at a reasonable cost in consideration of: customer service expectations, system reliability, technology innovation and public and employee safety and to maintain high levels of operating quality and efficiency.

The customer engagement requirements of RRFE are new. STEI is taking steps to comply with those requirements. Within the Application STEI identified a number of initiatives specifically rated to:

- Customer Access;
- Customer Communication;
- Working with Social Agencies;
- Roving Energy Manager; and
- Customer Engagement Surveys
    - External surveys conducted by UtiliyPulse
    - An internal survey conducted by customer service staff

The Parties recognize that, in this transition period, customer engagement is evolving, and is not yet comprehensive or perfectly designed and executed. STEI intends to more actively engage its customer over the next five-years.

Operational Effectiveness

St. Thomas Energy Inc. has described its operational effectiveness initiatives in the Application. STEI identified that the implementation of a Geographical Information System, ("GIS") will enable STEI to better manager distribution assets and provide the basis for a new and improved outage identification process and outage communications. STEI is also party to a Mutual Assistance Plan between eight distributors and is a member of two additional collaborative groups, Utility Collaborative Group ("UCS") and CustomerFirst initiative.

Operational effectiveness is an ongoing process, and STEI expects to implement additional operational effectiveness initiatives over the course of the next five years, as opportunities arise and as new industry best practices are identified. It is STEI's intent, when possible, to provide sustainable operating efficiencies, optimizing service levels and cost reductions to mitigate customer rate impacts. The Intervenors accept and support the Applicant's commitment to continuous improvement.

Public Policy Responsiveness

This Settlement Proposal provides the resources in the 2015 Test Year that will allow STEI to meet all known obligations mandated by government relevant to the Application in the Test Year, including in respect of renewable energy and any other current obligations that are mandated as a condition of St. Thomas Energy Inc.'s distribution licence.

Financial Performance

This Settlement Proposal will, if accepted by the Board, produce rates in the 2015 Test Year that will allow St. Thomas Energy Inc. to meet its obligations to its customers while maintaining its financial viability. STEI's goal is to achieve sustainable shareholder returns while providing sustainable operating efficiencies, optimizing service levels and cost reductions to mitigate customer rate impacts.

Based on the foregoing, and the evidence and rationale provided in this Settlement Proposal, the Parties agree that this Settlement Proposal is appropriate and recommend its acceptance by the Board.

ATTACHMENTS

The attachments below are provided on a preliminary basis and are subject to change following the Board's decision on the unsettled matters, STEI's updates to its cost of capital parameters and its cost of power forecast. The following attachments accompany this Settlement Proposal:

"**A**" – Board's Approved Issue List

"**B**" – Updated Chapter 2 Appendices (*from the Filling Requirements for Electricity Distribution Rate Applications*)

The following list identifies those Appendices that have been updated since the original April 30, 2014 filing:

OEB Appendix **2-AB**	Capital Expenditures
OEB Appendix **2-BA2**	Fixed Asset Continuity Schedules
OEB Appendix **2-CE**	Depreciation and Amortization Expense
OEB Appendix **2-H**	Other Operating Revenue
OEB Appendix **2-JA**	Summary of Recoverable OM&A Expenses
OEB Appendix **2-OA**	Capital Structure & Cost of Capital
OEB Appendix **2-P**	Cost Allocation
OEB Appendix **2-V**	Revenue Reconciliation
OEB Appendix **2-W**	Bill Impacts

1 PLANNING

1.1 Capital

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:

- customer feedback and preferences;
- productivity;
- benchmarking of costs;
- reliability and service quality;
- impact on distribution rates;
- trade-offs with OM&A spending;
- government-mandated obligations; and
- the applicant's objectives.

Status: Complete Settlement

Supporting Parties: STEI, Energy Probe, SEC, VECC

The Parties have agreed to a reduction of $88,000 in the Test Year capital. The capital reduction is largely based upon a shift of capital projects from 2014 into 2015 and from 2015 into 2016 based upon revised project completion percentages. Details of the reduction can be found under **Section 2.1.1 Rate Base Amount, Net Fixed Assets.**

The Parties accept that the Distribution System Plan filed in this proceeding, combined with the resources made available to STEI in the Test Year under the terms of this Settlement Proposal, provide an appropriate foundation to STEI in the Test Year to: (a) pursue continuous improvement in productivity; (b) attain appropriate system reliability and service quality objectives; and (c) maintain reliable and safe operation of its distribution system.

As per Exhibit 1 Tab 5 Schedule 1, STEI has described its ongoing productivity initiatives. The Parties accept STEI's ongoing commitment to continuous improvement.

The Parties accept that the Applicant's past reliability performance (which can be found in STEI's Application at Exhibit 2, Tab 8, Schedule 1) supports the Application, as amended by this Settlement Proposal, for 2015, and that the Settlement Proposal provides the Applicant with sufficient resources to maintain appropriate levels of reliability in the Test Year. St. Thomas Energy Inc. will continue to strive for reliability and customer satisfaction while maintaining a focus on safety and productivity.

For the purposes of settlement of the issues in this proceeding, the Parties accept STEI's confirmation that the resources available to it in the Test Year as a result of this Settlement Proposal will allow it to meet all obligations mandated by government as of the time of the filing of this Application, including in respect of renewable energy and any other obligations that are mandated as a condition of STEI's electricity distribution licence.

A summary of the Capital Additions on the *Applied-For vs. Settlement Basis is a follows*:

Settlement Table 1: *2015 Capital Additions DS Plan Applied-For Vs Settlement Basis*

Capital Additions - DS Plan vs Settlement			
	Original 2015 TY Filing	**Settlement Adjustments**	**Settlement 2015TY**
System Access	200,000	-	200,000
System Renewal	1,341,250	(172,000)	1,169,250
System Service	208,750	-	208,750
General Plant	513,000	84,000	597,000
Total Capital Additions	2,263,000	(88,000)	2,175,000
Contributed Capital	(100,000)	(15,000)	(115,000)
Net Capital Additions	**2,163,000**	**(103,000)**	**2,060,000**

Application Evidence:
Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 2 Tab 1 Schedule 6
Exhibit 2 Tab 1 DSP

Interrogatories:
2-Staff-7, 2-staff-8, 2-Staff-9, 2-staff-10, 2-staff-11, 2-Staff-12, 2-Staff-13, 2-Staff-14, 2-Staff-15, 2-Staff-16
2-EP-6, 2-EP-9
2-VECC-7, 2-VECC-8, 2-VECC-9, 2-VECC-11
2-SEC-7, 2-SEC-8, 2-SEC-9, 2-SEC-10, 2-SEC-11

Technical Conference:
Staff Ref 2-Staff-7, 2-Staff-11, 2-Staff-12, 2-EP-9, 2-EP-11

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:

- customer feedback and preferences;
- productivity;
- benchmarking of costs;
- reliability and service quality;
- impact on distribution rates;
- trade-offs with OM&A spending;
- government-mandated obligations; and
- the applicant's objectives.

Status: Complete Settlement

Supporting Parties: STEI, Energy Probe, SEC, VECC

St. Thomas Energy Inc. advises that its overall strategy is to continue to improve its operations, with employee safety and reliability being of foremost importance.

The current plan continues to focus efforts on providing an effective and efficient distribution system, maintaining system reliability standards, workforce investments, a safe work environment for employees and the public, and investments in billing and collecting, operating and financial systems in an effort to achieve increased efficiencies.

St. Thomas Energy Inc. will continue to strive for strong customer relations and continue to achieve customer satisfaction results that exceed the Ontario average.

The Parties accept STEI's statement of its overall objectives, and have agreed that the revised OM&A budget will allow STEI to achieve those objectives in the Test Year and the following IRM period.

The Parties agreements with respect to Customer Preferences and Expectations, Productivity, Benchmarking, Reliability, and other issues, described under Issue 1.1 above, apply as well to OM&A.

Notwithstanding the allocation of the OM&A reduction set out below, the Parties acknowledge that under the forward Test Year approach to rate-setting, STEI will retain the responsibility to make actual spending decisions during the Test Year, which may include variances from that presented below.

The parties agreed for the purposes of settlement on a 2015 test year OM&A budget of $4,490,000 which represents a 11.9% increase over 2013 actual OMA expenditures to account for one-time adjustments and allow for a reasonable increase in OM&A budget to account for inflation, growth, and other factors.

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

Settlement Table 2: *2015 OM&A Expenditures Applied-For vs Settlement Basis*

2015 OM&A Expenditures vs Settlement

	Original 2015 TY Filing	Technical Conference	Settlement Reallocation	Settlement Reduction	Settlement 2015TY
Operations	977,701	8,570	-	(19,380)	966,891
Maintenance	340,842	8,570	-	(19,380)	330,032
Customer Service	965,058	13,500	(23,400)	-	955,158
Administration	2,351,019	6,900	-	(120,000)	2,237,919
TOTAL OM&A	**4,634,620**	**37,540**	**(23,400)**	**(158,760)**	**4,490,000**

Evidence:

Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 2 Tab 1 Schedule 1
Exhibit 2 Tab 1 DSP
Exhibit 4 Tab 1 Schedule 1, 2, 3 and 4

Interrogatories:
4-Staff-21, 4-Staff-22, 4-Staff-23, 4-Staff-24, 4-Staff-25, 4-Staff-26, 4-Staff-27
1-EP-1, 1-EP-4, 2-EP-6, 3-EP-17, 4-EP-20, 4-EP-25
1-SEC-5, 4-SEC-16, 4-SEC-12, 4-SEC-13, 4-SEC-14, 4-SEC-16, 5-SEC-17, 4-SEC-18, 4-SEC-19, 4-SEC-20, 4-SEC-21, 4-SEC-22, 4-SEC-23,4-SEC-24, 4-SEC-25
4-VECC-30

Technical Conference:
1-EP-43TC
4-VECC-48, reference 4-VECC-30

2 REVENUE REQUIREMENT

2.1 Have all elements of the Base Revenue Requirement been appropriately determined in accordance with Board policies and practices?

Status: Complete Settlement

Supporting Parties: STEI, Energy Probe, SEC, VECC

Settlement Table 3 below provides the components of the Base Revenue Requirement on an Applied-For vs Settlement Basis. St. Thomas Energy Inc. has updated its Service Revenue Requirement as part of the interrogatory process.

Settlement Table 3: *Revenue Requirement Applied-For Vs Settlement Basis*

2015TY Revenue Requirement vs Settlement	Original 2015 TY Filing	Technical Conference	Settlement Agreement	$ Change	% Change
OM&A Expenses	4,634,620	4,672,160	4,490,000	(182,160)	-3.9%
Amortization / Depreciation	1,208,219	1,208,219	1,154,077	(54,142)	-4.5%
Income Taxes (Grossed up)	54,162	32,205	20,892	(11,313)	-35.1%
Return					
Deemed Interest Expense	886,973	879,786	791,290	(88,496)	-10.1%
Return on Deemed Equity	1,178,768	1,169,217	1,097,418	(71,799)	-6.1%
Service Revenue Requirement	**7,962,742**	**7,961,587**	**7,553,677**	**(407,910)**	**-5.1%**
Other Operating Revenue and Offsets	496,044	511,044	512,644	1,600	0.3%
Base Revenue Requirement	**7,466,698**	**7,450,543**	**7,041,033**	**(409,510)**	**-5.5%**

2.1.1 Rate Base Amount

In its Application, STEI proposed a forecast rate base of $31,484,195 for the 2015 Test Year, composed of $26,434,846 in Net Fixed Assets and $5,049,349 in Working Capital Allowance.

The agreed upon rate base of $29,311,377 is $1,917,720 less than the Technical Conference amount of $31,229,195. The agreed upon rate base is comprised of $25,762,736 in Net Fixed Assets and $3,548,641 in Working Capital Allowance. The working capital allowance is based upon a working capital rate of 9.75% (as opposed to the applied for rate of 13%).

With respect to the settled working capital rate of 9.75%, Intervenors have suggested that the Board's default rate of 13% is too high, particularly for a distributor, like STEI, that provides monthly as opposed to bi-monthly billing to the majority of its customers; for the purposes of Settlement STEI agreed to reflect a reduction in the Board's default 13% rate, using instead the negotiated 9.75% rate for the purpose of setting rates.

Settlement Table 4 below provides the rate base components on an *Applied-For vs Settlement Basis.*

Settlement Table 4: Rate Base Applied-For Vs Settlement Basis

2015TY Rate Base vs Settlement

	Original 2015 TY Filing	Technical Conference	Settlement Agreement	Changes
Gross Fixed Assets (average)	52,172,331	52,172,331	50,459,323	(1,713,008)
Accumulated Depreciation (average)	(25,737,485)	(25,737,485)	(24,696,587)	1,040,898
Average Net Fixed Assets	**26,434,846**	**26,434,846**	**25,762,736**	**(672,110)**
Allowance for Working Capital				
Controllable Expenses	4,634,620	4,672,160	4,490,000	(182,160)
Cost of Power	34,206,528	32,206,692	31,906,320	(300,372)
Working Capital Base	**38,841,148**	**36,878,852**	**36,396,320**	**(482,532)**
Working Capital Rate	**13.00%**	**13.00%**	**9.75%**	**-3.25%**
Allowance for Working Capital	5,049,349	4,794,251	3,548,641	(1,245,610)
Rate Base	**31,484,195**	**31,229,097**	**29,311,377**	**(1,917,720)**

Evidence

Application:
Exhibit 1 Tab 5 Schedule 1

Exhibit 2 Tab 1 Schedules 1, 2 and 3
Interrogatories:
1-Staff-2, 2-Staff-5, 4-Staff-29
2-EP-6, 2-EP-8, 4-EP-31

Technical Conference:
2-EP-44TC, 4-EP-50TC
2-VECC-40

Net Fixed Assets

The Parties reached a complete settlement with respect to the Net Fixed Assets.

The Parties agreed to the following changes in the Net Fixed Assets:

Gross Fixed Assets:

1. Removal of FMV markup on transferred assets, $548,000
2. 2014 net capital reductions, $107,000
3. 2014 increased contributed capital $15,000
4. 2015 net capital reductions, $88,000
5. 2015 increased contributed capital $15,000

Accumulated Amortization

1. Removal of FMV markup on transferred assets, $276,987
2. 2014 net capital reductions, $4,431
3. 2015 net capital reductions, $6,446

The 2014 and 2015 net capital reductions primarily reflect a shift of capital projects from 2014 into 2015 and from 2015 into 2016 based upon revised project in service dates. Additionally, a number of smaller projects that were not specifically identified in the original Application have been added to 2014 to reflect actual capital additions for that year. A further adjustment has been applied to the 2015 Test Year Capital Additions to reflect a more appropriate pacing of capital expenditures for the period 2015 to 2019.

Settlement Table 4a provides the details of the 2014 and 2015 net capital addition adjustments.

Settlement Table 4a: Capital Adjustments per Settlement Proposal

Capital Adjustments			
Project #	**Adjustment**	**2014**	**2015**
41	50% 2014, 50% 2015	(350,000)	350,000
42	50% 2014, 50% 2015	(160,000)	160,000
47	25% 2015, 75% 2016	-	(270,000)
49	25% 2015, 75% 2016	-	(156,000)
		(510,000)	84,000
STEI additional capital projects		403,000	-
Pacing adjustment			(172,000)
Total		**(107,000)**	**(88,000)**

Settlement Table 4b provides the project summary of the additional capital projects that have been added to the 2014 Bridge Year to reflect actual capital additions.

Settlement Table 4b: Capital Additions per Settlement Proposal

Miscellaneous Capital Jobs - 2014		
Job-#	**Description**	**Cost**
SU-210020	Pole replacement, Mandeville, Hemlock, Gaylord	25,000
SU-210116	Warehouse St., Park Ave to Fairview sub 9 conversion	65,000
SU-210135	Mandeville Rd W to First Ave	28,000
SU-210138	Replace switch, Bill Martin Parkway	20,000
Total		**138,000**
ND-210097	Orchard Park phase 4B	130,000
ND-210115	Remove T599 at Talbot St. install 3ph	10,000
ND-210117	Pole relocation Balaclava	10,000
ND-210124	Talbot St Global Pet Food - 200A. 120/208V	75,000
ND-210080	5 Frisch, 341 Talbot	10,000
Total		**235,000**
Miscellaneous Developer		**30,000**
Total Additions		**403,000**

Settlement Table 5 provides the Net Fixed Assets components on an Applied-For vs Settlement Basis.

Settlement Table 5: *Net Fixed Assets Applied-For vs. Settlement Basis*

2015TY Net Fixed Assets vs Settlement	Original 2014BY Filing	Settlement Agreement	Settled 2014 BY	Original 2015 TY Filing	Settlement Agreement	Settled 2015 TY
Opening Balance Gross Fixed Assets	49,565,396	(548,061)	49,017,335	52,082,188	(2,652,775)	49,429,413
Closing Balance Gross Fixed Assets	52,082,188	(2,652,775)	49,429,413	52,262,474	(773,241)	51,489,233
Average Net Fixed Assets	**50,823,792**	**(1,600,418)**	**49,223,374**	**52,172,331**	**(1,713,008)**	**50,459,323**
Opening Balance Accumulated Amortization	(24,686,619)	181,597	(24,505,022)	(25,913,481)	1,793,933	(24,119,548)
Closing Balance Accumulated Amortization	(25,913,481)	1,793,933	(24,119,548)	(25,561,490)	287,864	(25,273,626)
Average Balance Gross Fixed Assets	**(25,300,050)**	**987,765**	**(24,312,285)**	**(25,737,485)**	**1,040,898**	**(24,696,587)**
Average Net Fixed Assets	**25,523,742**	**(612,653)**	**24,911,089**	**26,434,845**	**(672,109)**	**25,762,736**

Evidence

Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 6 Tab 1 Schedule 1

Working Capital Allowance

The Parties reached a complete settlement on the issue of the working capital allowance.

The dollar amount of the cost of power and controllable expenses and the working capital percentage have all been agreed to.

Working Capital Allowance Percentage

As noted above, the Parties reached a settlement on the issue of the Working Capital Allowance percentage of 9.75%.

As per **Settlement Table 3,** STEI has updated its Revenue Requirement with respect to the settled issues and, as per **Settlement Table 4**. STEI has submitted its calculated Working Capital Allowance based on the settled amount 9.75% of the Cost of Power and eligible controllable expenses (i.e. Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General inclusive of property taxes).

Cost of Power and Controllable Expenses

Exhibit 2 Tab 1 Schedule 1 of the Application provides the components of Cost of Power and Controllable Expenses used to determine the Working Capital Allowance.

Settlement Table 6, below provides the Working Capital Allowance Base on an Applied-For vs Settlement Basis.

Settlement Table 6: *Working Capital Allowance Base Applied-For vs Settlement Basis*

2015 Working Capital Allowance vs Settlement

	Original 2015 TY Filing	Technical Conference	Settlement Reallocation	Settlement Reduction	Settlement 2015TY
Cost of Power	34,206,528	(1,999,836)		(300,372)	**31,906,320**
Operations	977,701	8,570		(19,380)	**966,891**
Maintenance	340,842	8,570		(19,380)	**330,032**
Customer Service	965,058	13,500	(23,400)	-	**955,158**
Administration	2,351,019	6,900		(120,000)	**2,237,919**
Working Capital	**38,841,148**	**(1,962,296)**	**(23,400)**	**(459,132)**	**36,396,320**

Cost of Power

The Parties have reached a complete settlement and agreed that STEI will adjust its Cost of Power to recognize the adjustment to the load forecast.

Refer to section 3.1.2 Load and Customer Forecast and CDM Adjustments.

Cost of Power - 2015 Settlement	
Electricity (Commodity)	**26,335,313**
Transmission - Network	**2,143,471**
Transmission - Connection	**1,602,954**
Wholesale Market Service	**1,285,092**
Rural Rate Protection	**379,686**
Smart Meter Entity Charge	**159,804**
GRAND TOTAL	**31,906,320**

Controllable Expenses

As noted above the Parties have agreed to make the following changes to STEI's controllable expenses, which in turn affects the working capital allowance calculation:

1. Reduce OM&A Expenses by $158,760 and an OM&A reallocation of $23,400, (for more details on the OM&A reduction, refer to *Issue 1.2* above)

Evidence:

Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 2 Tab 1 Schedule 1
Exhibit 6 Tab 1 Schedule 1

2.1.2 OM&A Expense Amount

The Parties have reached a complete settlement with regards to the OM&A expense for the 2015 Test Year and agreed to an OM&A expenditure reduction of $158,760 and an OM&A expenditure reallocation to account 4380 of $23,400. The Parties acknowledge that STEI will retain the responsibility to make actual spending decisions during the Test Year.

The Parties have agreed for the purposes of settlement that the adjusted levels of OM&A expenditures are reasonable and that the expenditures are expected to enable St. Thomas Energy Inc. to maintain and improve its reliability and service quality. The Parties agreed that the proposed OM&A expenditures are appropriately balanced, and that the agreed-upon revenue requirement (including reductions in OM&A expenditures to those which were proposed in the Application) is expected to permit St. Thomas Energy Inc. to meet its regulatory obligations and operate and maintain its distribution system at a high standard while maintaining its financial viability.

Refer to **Settlement Table 2** above for the revised OM&A budget for the Test Year.

Evidence:

Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 2 Tab 1 Schedule 1
Exhibit 2 Tab 1 DSP
Exhibit 4 Tab 1 Schedule 1, 2, 3, and 5

Interrogatories:
4-Staff-21, 4-Staff-22, 4 -Staff-23, 4-Staff-24, 4-Staff-25, 4-Staff-26, 4-Staff-27, 4-Staff-28
1-EP-1, 1-EP-4, 2-EP-6, 3-EP-17, 4-EP-19, 4-EP-20, 4-EP-21, 4-EP-22, 4-EP-23, 4-EP-24, 4-EP-25, 4-EP-26, 4-EP-27, 4-EP-28, 4-EP-29, 4-EP-30
1-SEC-1, 1-SEC-3, 1-SEC-4, 1-SEC-5, 1-SEC-6, 4-SEC-16, 4-SEC-17, 4-SEC-24, 4-SEC-25
4-VECC-21, 4-VECC-22, 4-VECC-23, 4-VECC-24, 4-VECC-25, 4-VECC-26, 4-VECC-27, 4-VECC-28
4-VECC-29, 4-VECC-30

Technical Conference:
1-EP-43TC
4-VECC-48, reference 4-VECC-30

2.1.3 Depreciation and Amortization Expense

The Parties have reached a complete settlement with regards to the Depreciation and Amortization Expense for the 2015 Test Year and agreed that a reduction in Depreciation and Amortization Expense of $54,142 will be made.

$47,695 of the Depreciation and Amortization reduction is directly related to the change from Fair Market Value to Net Book Value on the transfer of assets to St. Thomas Energy Inc. from its affiliate on January 1, 2012.

Refer to Section 5.1 for more details.

The Application calculates Depreciation and Amortization Expense on the basis of the half-year rule for capital additions during the Test Year.

Settlement Table 7: *Depreciation Applied-For vs. Settlement Basis*

2015 Amortization/Depreciation vs Settlement				
	Original 2015 TY Filing	Technical Conference	Settlement Adjustments	Settlement 2015TY
Amortization/Depreciation	1,208,219	-	(54,142)	1,154,077

Evidence:

Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 1 Tab 5 Schedule 17
Exhibit 2 Tab 1 Schedules 1, 2, 3 and 7
Exhibit 4 tab 1 Schedule 1, 11

Interrogatories:
1-Staff-3, 2-Staff-6, 4-Staff-29
2-EP-6, 2-EP-10, 4-EP-31
3-VECC-13, 4-VECC-30,

2.1.4 Payments in Lieu of Taxes ("PILs") Amount

The Parties reached a complete settlement with respect to the PILs. STEI has recalculated its PILs in light of this Settlement Proposal, and that amount is included in **Settlement Table 3**.

Settlement Table 8: *Payment in Lieu of Taxes vs. Settlement Basis*

2015 Payment in Lieu of Taxes vs Settlement				
	Original 2015 TY Filing	Technical Conference	Settlement Adjustments	Settlement 2015TY
Payment in Lieu of Taxes	54,162	(21,957)	(11,313)	20,892

Evidence:

Application:
Exhibit 4 Tab 1 Schedule 12

Interrogatories:
4-Staff-31
4-EP-32, 4-EP-33, 4-EP-34, 4-EP-35, 4-EP-36

Technical Conference:
4-EP-53TC

2.1.5 Capital Structure, Rate of Return on Equity and Short Term Debt Rate

Settlement Table 9 below provides Capital Structure, Rate of Return on Equity and Short Term Debt Rate components used in the determination of Deemed Debt and Equity and Cost of Capital Parameters. The Capital Structure, Rate of Return on Equity and Short Term Debt Rate have been settled.

Settlement Table 9: *Capital Structure and Return Applied-For Vs Settlement Basis*

2015 Capital Structure vs Settlement				
	Original 2015 TY Filing	Technical Conference	Settlement Adjustments	Settlement 2015TY
OEB Deemed Debt/Equity	31,484,195	(255,099)	(1,917,719)	29,311,377

Capital Structure

In determining the cost of capital, St. Thomas Energy Inc. followed the Board's Report on Cost of Capital for Ontario's Regulated Utilities, issued December 11, 2009. To comply with this report, STEI has prepared this Application with deemed capital structure of 56% Long Term debt, 4% Short Term debt and 40% Equity.

The Parties have reached a complete settlement on the issue and agreed that STEI's proposed capital structure is appropriate.

Cost of Capital Parameters

The Parties have agreed to make the following changes, as shown in Settlement Table 10 below, to STEI's Cost of Capital Parameters:

- STEI will set its weighted long-term debt rate of 4.67% based upon the weighted-average of the following debt instruments:
    - City of St. Thomas Promissory note, $7,714,426 at 4.88%
    - Bank of Nova Scotia Revolving Term Loan $3,500,000:
        - Fixed by interest swap, $1,750,000 at 4.87%
        - Prime plus 0.55%, $1,750,000 at 3.55%

Settlement Table 10: *Cost of Capital vs. Settlement Basis*

2015 Capital Structure vs Settlement	Original 2015 TY Filing	Technical Conference	Settlement Adjustments	Settlement 2015TY
Long-Term Debt	4.88%	0.00%	-0.21%	4.67%
Short - Tern Debt	2.11%	0.00%	0.00%	2.11%
Equity	9.36%	0.00%	0.00%	9.36%

STEI will update its Cost of Capital parameters for the long-term debt, short-term debt and equity percentages and rates according to the Board's next Cost of Capital Parameter Updates for January 1, 2015 Cost of Service applications, which is expected to be released in November 2014.

Evidence:

Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 5 Tab 1 Schedule 1
Exhibit 5 Tab 1 Schedule 2

Interrogatory:
5-EP-38, 5-EP-39
5-VECC-31

Technical Conference
5-EP-54TC

2.1.6 Deemed Interest Expense Amount

The Parties have reached a complete settlement, subject to updates to the Cost of Capital Parameters. The Parties have agreed to make the following changes to the Deemed Interest Expense Amount used in the determination for the Company's Base Revenue Requirement:

- Update the Short Term Debt and Long Term Debt rate parameters as outlined above, at the time the Board issues its Decision and Order with respect to STEI's 2015 Cost of Service Application.

Refer to **Settlement Table 10** above for more details.

Evidence:

Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 5 Tab 1 Schedule 1
Exhibit 5 Tab 1 Schedule 2

2.1.7 Deemed Return on Equity Amount

The Parties have reached a complete settlement subject to updates to the Cost of Capital Parameters and Cost of Power Forecast. The Parties agreed to make the following change to the Deemed Return on Equity Amount used in the determination of the STEI's Base Revenue Requirement.

- STEI will update its Return on Equity Percentage according to the Board's next Cost of Capital Parameter Updates for 2015 Cost of Service Applications, which is expected to be released in November 2014.

Evidence:

Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 5 Tab 1 Schedule 1
Exhibit 5 Tab 1 Schedule 2

Interrogatory:
5-EP-37
5-VECC-32
4-SEC-26

2.1.8 Other Revenue

The Parties have reached a complete settlement and agreed to make the following change to the Other Revenue used as the revenue offset for the determination of Base Revenue Requirement:

- The Parties agreed that STEI's forecasted other revenues would be increased by $1,600 for the 2015 Test Year from the amount filed in the Application which has the effect of lowering the Base Revenue Requirement by the same amount.

- The $1,600 is comprised of:
    - Increased notional allocation of postage costs to its affiliate in the amount of $25,000 in relation to the Water and Sewer Billing Services, largely offset by;

    - Transfer of OM&A expenditures in the amount of $23,400 to account 4380, also in relation to the Water and Sewer Billing and Collecting Services.

Evidence:

Application:
Exhibit 3 Tab 1 Schedule 6

Interrogatory:
8-Staff-33
3-EP-16, 3-EP-17

Technical Conference
3-VECC-46

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

Status: **Complete Settlement**

Supporting Parties: STEI, Energy Probe, SEC, VECC

The Parties agree that the Base Revenue Requirement has been accurately determined with one exception: (1) the updates that STEI will make to its cost of capital parameters. Once the Board makes its decision with respect to STEI's 2015 Cost of Service Rate Application, STEI will make the adjustments as required to reflect the Board Decision.

Evidence:

Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 3 Tab 1 Schedule 5
Exhibit 6 Tab 1 Schedule 1

Interrogatory:
1-EP-3, 1-EP-4

Technical Conference
3-EP-49TC
4-SEC-32

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, and, to the extent applicable, are they an appropriate reflection of the energy and demand requirements of the applicant's customer?

Status: Complete Settlement

Supporting Parties: STEI, Energy Probe, SEC, VECC

Evidence:

Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 3 Tab 1 Schedule 1, 2, 3, 4 and 5
Exhibit 7 Tab 1 Schedule 1, 2, and 3
Exhibit 8, Tab 1, Schedule 1

Interrogatory:
3-Staff-17, 3-Staff-18, 3-Staff-19, 3-Staff-20
3-VECC-14, -VECC-15, 3-VEC-16, 3-VECC-17, 3-VECC-18, 3-VECC-19, 3-VECC-20, 7-VECC-33
7-VECC-34, 7-VECC-35, 8-VECC-36
3-EP-12, 3-EP-13, 3-EP-14, 3-EP-15, 7-EP-41

Technical Conference:
3-VECC-41, 3-VECC-44, 3-VECC-45, 8-VECC-49
7-EP-58-TC, 8-EP-59TC

3.1.1 Proposed Customer forecast

The Parties have reached a complete settlement and agreed with the Proposed Customer forecast as filed in the Application.

3.1.2 Load and Customer Forecast and CDM Adjustments

The Parties have reached a complete settlement regarding STEI's Load and Customer Forecast and CDM Adjustments. The Parties agreed on all aspects of the load forecast, customer forecast, and CDM Adjustments as filed with an exception of:

- STEI agreed to add back 112,045 kWh per month and 235kW per month for a single GS>50 customer that has closed and has a reduced "maintenance" load that was omitted in the original application;

- STEI agreed to update the 2014 CDM forecasts and the impact in the 2015 load.

The adjusted customer load forecast and CDM adjustment is presented in the following table.

Adjustment To Load Forecast
St. Thomas Energy Inc.

Retail kWh	Weather Normalized 2015F (Elenchus) A	C = A / B	CDM Load Forecast Adjustment E = D * C	2015 CDM Adjusted Load Forecast F = A - E		Adjustment for Add Back of GS > 50 customer	2015 Final Forecast
Residential (kWh)	122,350,506	43%	1,746,598	120,603,908			120,603,908
GS<50 (kWh)	41,245,470	14%	588,794	40,656,676			40,656,676
GS>50 (kW)	118,183,915	41%	1,687,119	116,496,796		112,045	116,608,841
Street Lights (kW)	3,163,332	1%	45,158	3,118,174			3,118,174
USL (kWh)	23,170	0%	331	22,839			22,839
Total Customer (kWh)	284,966,393	100%	4,068,000	280,898,393	-1.4%	112,045	281,010,438
	B		D				

kW	Weather Normalized 2015F (Elenchus) G	I = G / H	CDM Load Forecast Adjustment * J = G / A * E	2015 CDM Adjusted Load Forecast K = G - J		Adjustment for Add Back of GS > 50 customer	2015 Final Forecast
Residential (kWh)	-	0%		-			-
GS<50 (kWh)	-	0%		-			-
GS>50 (kW)	301,426	97%	4,303	297,123		237	297,360
Street Lights (kW)	8,754	3%	125	8,629			8,629
USL (kWh)	177	0%	3	174			174
Total Customer (kWh)	310,357	100%	4,430	305,927	-1.4%	237	306,163

The following table provides the updated load forecast for the "maintenance" load of the closed GS>50, that was added back to the load forecast, based upon 12-months consumption from November 1, 2013 to October 1, 2014.

Sum of Usage	Stat Code			Billed Demand	
Read Date	Before Loss	Losses	Grand Total	Read Date	Total
2013-11-01	106,750.03	2,636.73	**109,386.76**	2013-11-01	196.42
2013-12-01	116,679.67	2,881.99	**119,561.66**	2013-12-01	290.98
2014-01-01	146,714.96	3,623.86	**150,338.82**	2014-01-01	240.57
2014-02-01	142,966.35	3,531.27	**146,497.62**	2014-02-01	227.35
2014-03-01	144,906.04	3,579.18	**148,485.22**	2014-03-01	251.16
2014-04-01	166,420.89	4,110.60	**170,531.49**	2014-04-01	289.31
2014-05-01	119,086.44	2,941.44	**122,027.88**	2014-05-01	274.72
2014-06-01	111,204.51	2,746.75	**113,951.26**	2014-06-01	256.13
2014-07-01	85,422.31	2,109.93	**87,532.24**	2014-07-01	208.87
2014-08-01	89,061.13	2,199.81	**91,260.94**	2014-08-01	160.85
2014-09-01	61,612.90	1,521.84	**63,134.74**	2014-09-01	284.52
2014-10-01	53,713.04	1,326.71	**55,039.75**	2014-09-01	161.31

3.1.3 Loss Factors

The Parties have reached a complete settlement and agreed that the Proposed Loss Factors are appropriate as filed in the Application. The loss factor was increased from 3.60% to 3.93%. The original loss factor as calculated per Board Appendix 2-R was not completed properly. The following adjustments were made during the technical conference that resulted in increasing the loss factor.

- The Supply Facilities Loss Factor shown in Row H of Appendix 2-R was an error. STEI is using 1.0035 as the SFLF as provided in its 2011 COS application.

- Line B should have had zero entered as opposed to being left blank for each of the years with no figures.

Evidence:

Application:
Exhibit 2 Tab 1 Schedule 1
Exhibit 8 Tab 1 Schedule 8

Interrogatory:
8-VECC-37

3.1.4 Billing Determinants

The Parties have agreed on the issue regarding the Billing Determinants that STEI computed and used in its Application.

There was complete settlement regarding STEI's forecast of the number of customers for each class, the number of connections for non-metered customer classes and to all volumetric kWh and kW billing determinants as discussed in issue 3.1.2 above.

Billing Determinants

	Customer / Connections	kWh	kW
Residential	15,120	120,603,908	-
General Service < 50 kW	1,737	40,656,676	-
General Service > 50	144	116,608,841	297,360
Sentinel Lighting	52	22,839	174
Street Lighting	4,918	3,118,174	8,629
Totals	**21,971**	**281,010,438**	**306,163**

Evidence:

Application:
Exhibit 1 Tab 1 Schedule 1
Exhibit 3 Tab 1 Schedule 1
Exhibit 8 Tab 1 Schedule 8

Interrogatory:
3-Staff-18

3.2 Is the proposed cost allocation methodology including the revenue-to-cost ratios appropriate?

Status: Complete Settlement

Supporting Parties: STEI, Energy Probe, SEC, VECC

The Parties have reached a complete settlement with respect to the allocations resulting from the cost allocation study performed by STEI and the revenue-to-cost ratios determined by STEI with the following adjustments:

- It was agreed that in reducing the Sentinel Lighting revenue-to-cost ratio to the maximum, 120%, STEI will increase the revenue-to-cost ratio for only the GS > 50 class, and leave all other rate class revenue-to-cost ratios at their existing level. STEI notes that after this adjustment, GS > 50 continues to experience the lowest revenue-to-cost ratio.

STEI has provided Appendix B, which includes the Chapter 2 Appendix 2-P which details the proposed revenue to cost ratios for all classes based on the updated information contained in the Cost Allocation model referenced above.

STEI has provided an Appendix D which includes an updated output sheet O1 Revenue to Cost|RR from the Cost Allocation Study Model based on the fully-settled Base Revenue Requirement included in Issue 2.1 above.

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

Status: Complete Settlement

Supporting Parties: STEI, Energy Probe, SEC, VECC

The parties have reached a complete settlement with respect STEI's proposal for rate design with the following adjustment.

- The fixed charge for GS > 50 customer class will remain at the 2014 Board Approved rate of $72.31, **(see Section 3.4)**.

STEI's original application requested a GS > 50 fixed charge of $81.43 comprised of the May 1, 2014 service charge of $72.31 and the Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement of $9.12; the Parties agreed as part of the settlement to instead leave the service charge at the status quo level, which is already in excess of the calculated ceiling.

Evidence:

Application:
Exhibit 8

Interrogatory:
8-EP-42
8-VECC-36

Technical Conference:
8-VECC-49

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

Status: Complete Settlement

Supporting Parties: STEI, Energy Probe, SEC, VECC

The Parties have reached a complete settlement with respect to STEI's proposals regarding fixed/variable ratios with the following adjustment:

- STEI will maintain the existing fixed/variable proportions for rate design purposes except where the resulting fixed rate is either currently at or above the ceiling rate (see above with respect to the Gs>50 fixed charge). If the existing fixed rate is at or above the ceiling rate then the fixed rate will not be increased.

Settlement Table 11 provides a comparison of the resulting fixed and variable distribution revenue splits for each of the proposed Customer Classes on an Applied-For vs Settlement Basis.

Settlement Table 11: *Fixed Variable Ratios vs. Settlement Basis*

Class	Applied				Settled			
	Fixed $	Variable $	Fixed %	Variable %	Fixed $	Variable $	Fixed %	Variable %
Residential	2,734,449	2,155,773	55.9%	44.1%	2,585,496	2,029,331	56.0%	44.0%
GS < 50	513,043	686,546	42.8%	57.2%	484,884	644,690	42.9%	57.1%
GS > 50	140,711	1,007,731	12.3%	87.7%	124,952	955,817	11.6%	88.4%
Sentinel light	3,119	1,063	74.6%	25.4%	2,934	989	74.8%	25.2%
Street light	223,941	322	99.9%	0.1%	211,639	302	99.9%	0.1%
Base Revenue	**3,615,263**	**3,851,435**			**3,409,904**	**3,631,129**		

Settlement Table 12 below provides a comparison of the fixed and variable distribution rates for each of the proposed Customer Classes on an Applied-For vs Settlement Basis.

Settlement Table 12: Comparison of Fixed/Variable Distribution Rates Applied-For Vs Settlement Basis

Settlement Table 12: *Fixed Variable Rates vs. Settlement Basis*

		Applied		Settlement	
Class	**Volumetric**	**Fixed $**	**Variable $**	**Fixed $**	**Variable $**
Residential	kWh	15.07	0.01780	14.25	0.01680
GS < 50	kWh	24.61	0.01680	23.26	0.01590
GS > 50	KW	81.43	3.62580	72.31	3.47180
Sentinel light	kW	5.00	6.04100	4.70	5.68300
Street light	kW	3.79	0.03710	3.59	0.03500

Evidence:

Application:
Exhibit 8

3.5 Are the proposed Retail Transmission Service Rates appropriate?

Status: Complete Settlement

Supporting Parties: STEI, Energy Probe, SEC, and VECC:

The Parties have reached a complete settlement with regard to the Retail Transmission Service Rates ("RTSR"). STEI updated the RTSR's to reflect the most recent Uniform Transmission Rates and Sub-transmission rates available at that time as set out in Technical Conference Undertaking JT1.6.

STEI will revise the RTSR model if updated rates are available before the Board issues its final rate order for the application.

Evidence:

Application:
Exhibit 8 Tab 1 Schedule 2

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?

Status: Complete Settlement

Supporting Parties: STEI, Energy Probe, SEC, VECC

Subject to Issue 4.2 below, in reaching a complete agreement the Parties have accepted STEI's evidence regarding the impacts of any changes in accounting standards, policies, estimates and adjustments, and the appropriateness of the ratemaking treatment of those changes.

Evidence:

Application:
Exhibit 1 Tab 4 Schedule 2
Exhibit 1 Tab 5 Schedule 4

Interrogatories:
2-Staff-6, 9-Staff-37, 9-Staff-38

Technical Conference:
Board Staff – Reference 9-Staff-38

4.2 Are the applicant's proposals for deferral and variance accounts including the balances in the existing accounts and their disposition and then continuation of existing accounts appropriate?

Status: Complete Settlement

Supporting Parties: STEI, Energy Probe, SEC, VECC

The Parties were able to reach an agreement with regard to the amounts and disposition periods for all Deferral and Variance Accounts requested for disposition.

For Account 1576 – Accounting Changes under CGAAP Deferral Account, see section 4.2.2 below.

Evidence:

Application:
Exhibit 1 Tab 5 Schedule 1
Exhibit 9

Interrogatories:
9-Staff-35, 9-Staff-36, 9-Staff-37, 9-Staff-38, 9-Staff-39, 9-Staff-40, 9-Staff-41, 9-Staff-42
9-VECC-38

Technical Conference:
Board Staff – Reference 9-Staff-37, 9-Staff-38

4.2.1 Deferral and Variance Accounts

The Parties were able to reach an agreement with regard to the amounts and disposition periods for all Deferral and Variance Accounts requested for disposition including Account 1576 – Accounting Changes under CGAAP Deferral Account, see **section 4.2.2 below**.

STEI did not request disposition of account 1508 Other Regulatory Assets – Sub-Account – Deferred IFRS Transition Costs as STEI is anticipating additional material costs in the 2015 Test Year with regards to financial reporting.

In addition, the Parties agreed to the inclusion of two rate riders that were not requested for disposition in STEI's original Application.

- Recovery of account 1568 LRAMVA
  - The LRAMVA amount was originally not deemed to meet the materiality threshold. As STEI had filed an LRAMVA within 2014 IRM Application EB-2013-0171 it was agreed that the balance of $32,131 should be disposed.

- Inclusion of account 1551 SME charges.
  - The original EDVAR model did not include this item. STEI refiled an updated EDVAR model that included recovery of the SME charges in the amount of $10,016.

Smart Meter Capital and Recovery Offset Variance - Sub-Account 1555 - Stranded Meter Costs.

Agreement on the amount requested for recovery in the amount of $422,504.

In STEI's original application, STEI identified that they were unable to calculate the specific recovery of the Net Book Value by customer class and as such was seeking a Residential and GS<50 kW recovery based upon 2015TY customer count. In response to Board staff interrogatory 9-42, STEI revised the customer class specific rate rider by determining the weighted average of the installed meter costs based upon the number of meters removed per the Board Smart Meter model included in Board Decision and Order EB-2012-0348 and the average installed metered costs based upon the cost allocation model included in EB-2010-0141.

The change in the Stranded Meter Rate Rider is as follows:

Stranded Meter Rate Rider

	Applied for	Settlement
Residential	0.42	0.37
GS<50	0.42	0.79

4.2.2 Account 1576 - Accounting Changes under CGAAP Deferral Account

STEI's original Application, despite identifying an account 1576 recovery of $85,019, requested that the amount be considered as having no balance owing to the utility.

The Parties have accepted STEI's original proposal that, although the amount to be disposed in account 1576, even after adjusting the calculation to reflect the NBV of the assets transferred from an affiliate to STEI as of January 1, 2012, is a net credit to the benefit of STEI, 1576 will be considered as having no balance owing.

What follows is a reconciliation of the calculated amount in 1576 for reference purposes; as noted the proposal, which was been accepted by the Parties, is to treat the account as having a zero balance for the purpose of clearance.

STEI has reproduced the original Board Appendix 2-ED:

Appendix 2-ED
Account 1576 - Accounting Changes under CGAAP
2012 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

	2011 Rebasing Year	2011	2012	2013	2014	2015 Rebasing Year	2016	2017	2018
Reporting Basis	CGAAP	IRM	IRM	IRM	IRM	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Actual	Forecast	Forecast			
			$	$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1			18,970,924	24,537,286	24,907,841				
Net Additions - Note 4			7,931,734	2,313,499	3,382,552				
Net Depreciation (amounts should be negative) - Note 4			-2,365,372	-1,942,944	-2,036,666				
Closing net PP&E (1)			24,537,286	24,907,841	26,253,727				
PP&E Values under revised CGAAP (Starts from 2012)									
Opening net PP&E - Note 1			18,970,924	24,491,365	24,878,778				
Net Additions - Note 4			7,069,689	1,523,521	2,516,792				
Net Depreciation (amounts should be negative) - Note 4			-1,549,248	-1,136,108	-1,226,862				
Closing net PP&E (2)			24,491,365	24,878,778	26,168,708				
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			45,921	29,063	85,019				

STEI provided the following revised Account 1576 balance in response to Board Staff Technical Conference question reference 9-Staff-37. The revised table identified and quantified the components of the Account 1576 balance.

The revised calculation increased the amount owing to STEI by $277,069 from $85,019 to $362,088 as provided in the table on the following page.

	2012	2013	2014	Total
Amortization change	(812,124)	(806,836)	(809,804)	(2,428,764)
OM&A Increase	661,071	588,867	665,125	1,915,063
Additional amortization (excluding smart meters)	283,778	273,078	318,932	875,789
Net Shareholder Impact	**132,725**	**55,109**	**174,253**	**362,088**

During the settlement process it was agreed that STEI would provide a new table that calculated the Account 1576 balance excluding the fair market value on the January 1, 2012 asset transfer from an affiliate.

Board staff requested STEI has provided Settlement Table 13, a reconciliation table to support the changes and the ending balance in account 1576, on the same basis as the table provided in the Technical Conference response.

The Account 1576 balance has been reduced by $318,499 to $43,589 from $362,088.

Settlement Table 13, Account 1576 Summary

Account 1576

	2012	2013	2014	Total
Amortization change	(812,124)	(806,836)	(809,804)	(2,428,764)
OM&A Increase	661,071	588,867	665,125	1,915,063
Additional OM&A	283,778	273,078	318,932	875,789
Deduct FMV	(459,496)	93,032	47,965	(318,499)
Account 1576	**(326,771)**	**148,141**	**222,218**	**43,589**

The following table provides the summary of the removal of the fair market value that reconciles to STEI's audited financial statements (note 6) and to Settlement Table 13.

Settlement Table 14, Removal of FMV

	Opening	Closing	
FMV Transfer, 2012	586,061		
Amortization 2012	(126,565)	**459,496**	**Equals Note 6 2012 audited F/S**
2013 Disposal	(38,000)		
Disposal Acc Amort	7,600		
Amortization 2013	(62,632)	**366,464**	**Equals Note 6, 2013 audited F/S**
Amortization 2014	(47,965)	**318,499**	**2014 Ending BV**
Amortization 2015	(47,965)	**270,534**	**2015 Ending BV**

STEI has provided a revised Board Appendix 2-ED on the following page that reconciles to the Settlement Table 13 balance of $43,589.

Appendix 2-ED
Account 1576 - Accounting Changes under CGAAP
2012 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

	2011 Rebasing Year	2011	2012	2013	2014	2015 Rebasing Year	2016	2017	2018
Reporting Basis	CGAAP	IRM	IRM	IRM	IRM	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Actual	Forecast	Forecast			
			$	$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1			18,970,924	24,164,594	24,700,148				
Net Additions - Note 4			7,555,042	2,478,498	3,548,815				
Net Depreciation (amounts should be negative) - Note 4			-2,361,372	-1,942,944	-2,036,666				
Closing net PP&E (1)			24,164,594	24,700,148	26,212,297				
PP&E Values under revised CGAAP (Starts from 2012)									
Opening net PP&E - Note 1			18,970,924	24,491,365	24,878,778				
Net Additions - Note 4			7,069,689	1,523,521	2,516,792				
Net Depreciation (amounts should be negative) - Note 4			-1,549,248	-1,136,108	-1,226,862				
Closing net PP&E (2)			24,491,365	24,878,778	26,168,708				
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			-326,771	-178,630	43,589				

Effect on Deferral and Variance Account Rate Riders			
Closing balance in Account 1576	43,589	**WACC**	6.44% confirm
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	14,036	**# of years of rate rider disposition period**	5
Amount included in Deferral and Variance Account Rate Rider Calculation	57,625		

5 Other

5.1 Are the changes due to STEI's restructuring appropriate and reflective of the Board's accounting Policies?

Status: Complete Settlement

Supporting Parties: STEI, Energy Probe, SEC, VECC

As part of the Application, STEI proposed with respect to the restructuring, to recognize assets transferred from its affiliate on January 1, 2012 at their Fair Market Value as noted in STEI's audited financial statements, Exhibit 1 Tab 5 Schedule 3.

The Parties have agreed as part of this settlement proposal that STEI will recognize the assets transferred from its affiliate at their Net Book Value effective January 1, 2012. The impact of this change in recognized value is reflected in Settlement Table 14.

With this change, the Parties agree as part of this settlement proposal that the changes due to STEI's restructuring are appropriate and properly reflective of the Board's accounting policies.

Evidence:

Application:
Exhibit 1 Tab 5 Schedule 17
Exhibit 4 Tab 1 Schedule 1, 2

Interrogatories:
1-Staff-1

Appendix A - Board's Approved Issues List

ISSUES LIST
EB-2014-0113
St. Thomas Energy Inc.

1. PLANNING

1.1 Capital

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:

- customer feedback and preferences;
- productivity;
- benchmarking of costs;
- reliability and service quality;
- impact on distribution rates;
- trade-offs with OM&A spending;
- government-mandated obligations; and
- the applicant's objectives.

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:

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

2. REVENUE REQUIREMENT

2.1 Have all elements of the Base Revenue Requirement, been appropriately determined in accordance with Board policies and practices?

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

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, and, to the extent applicable, are they an appropriate reflection of the energy and demand requirements of the applicant's customers?

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

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

3.4 Are the proposed Retail Transmission Service Rates appropriate?

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?

4.2 Are the applicant's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition and the continuation of existing accounts appropriate?

5. Other

5.1 Are the changes due to STEI's restructuring appropriate and reflective of the Board's accounting policies?

Appendix B - Updated Chapter Appendices

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2015*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2010			2011			2012			2013			2014			2015	2016	2017	2018	2019
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	953,819	693,867	-27.3%	759,731	735,219	-3.2%	551,200	3,943,790	615.5%	719,000	580,417	-19.3%	200,000		-100.0%	200,000	200,000	200,000	200,000	200,000
System Renewal	872,154	778,473	-10.7%	1,143,467	1,146,535	0.3%	978,700	1,077,181	10.1%	827,423	1,008,816	21.9%	1,600,000		-100.0%	1,169,250	1,590,000	1,530,000	1,215,000	1,560,000
System Service	-	45,076	--	285,510	-	-100.0%	-	-	--	-	-	--	-		--	208,750	-	-	305,000	-
General Plant	-	-	--	-	-	--	743,500	2,381,685	220.3%	888,000	538,637	-39.3%	621,050		-100.0%	597,000	436,000	458,000	265,000	222,000
Contributed Capital	- 302,000	- 384,629	27.4%	- 251,000	- 266,363	6.1%	- 230,500	- 318,521	38.2%	- 311,000	- 596,144	91.7%	- 115,000			- 115,000	- 115,000	- 115,000	- 115,000	- 115,000
TOTAL EXPENDITURE	1,523,973	1,132,787	-25.7%	1,937,708	1,615,391	-16.6%	2,042,900	7,084,134	246.8%	2,123,423	1,531,726	-27.9%	2,306,050	-	-100.0%	2,060,000	2,111,000	2,073,000	1,870,000	1,867,000
System O&M	$ 988,508	$1,085,310	9.8%	$ 916,682	$ 923,291	0.7%	$ 1,371,654	$1,311,270	-4.4%	$1,305,830	$1,224,643	-6.2%	$1,259,102		-100.0%	$1,318,543	$1,346,233	$ 1,374,503	$1,403,368	$1,432,839

Fixed Asset Continuity Schedule - CGAAP

Year **2012**

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ -	$ 476,100		$ 476,100	$ -	-$ 97,936		-$ 97,936	$ 378,164
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 6,734	$ 904		$ 7,638	$ -			$ -	$ 7,638
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 850,125	$ -		$ 850,125	-$ 831,276	-$ 836		-$ 832,112	$ 18,013
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,458,646	$ 188,797		$ 8,647,444	-$ 3,876,606	-$ 120,686		-$ 3,997,292	$ 4,650,151
47	1835	Overhead Conductors & Devices	$ 7,482,814	$ 195,298		$ 7,678,113	-$ 3,933,151	-$ 69,636		-$ 4,002,787	$ 3,675,326
47	1840	Underground Conduit	$ 3,936,612	$ 459,743		$ 4,396,355	-$ 1,906,280	-$ 83,919		-$ 1,990,199	$ 2,406,156
47	1845	Underground Conductors & Devices	$ 8,017,557	$ 559,389		$ 8,576,946	-$ 3,749,510	-$ 141,840		-$ 3,891,350	$ 4,685,596
47	1850	Line Transformers	$ 9,153,189	$ 338,735		$ 9,491,924	-$ 4,893,407	-$ 149,108		-$ 5,042,515	$ 4,449,408
47	1855	Services (Overhead & Underground)	$ 5,204,841	$ 158,551		$ 5,363,391	-$ 2,335,566	-$ 87,925		-$ 2,423,491	$ 2,939,900
47	1860	Meters	$ 2,441,644	$ 4,238		$ 2,445,881	-$ 1,519,263	-$ 76,024		-$ 1,595,287	$ 850,594
47	1860	Meters (Smart Meters)	$ -	$ 3,100,869		$ 3,100,869	$ -	-$ 571,777		-$ 571,777	$ 2,529,092
N/A	1905	Land	$ 174,188			$ 174,188	$ -			$ -	$ 174,188
47	1908	Buildings & Fixtures	$ 2,385,250	$ 15,493		$ 2,400,743	-$ 900,207	-$ 36,971		-$ 937,178	$ 1,463,565
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ 71,937		$ 71,937	$ -	-$ 7,194		-$ 7,194	$ 64,743
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ 136,794		$ 136,794	$ -	-$ 40,379		-$ 40,379	$ 96,415
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -	$ 378,015		$ 378,015	$ -	-$ 38,957		-$ 38,957	$ 339,058
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -	$ 85,392		$ 85,392	$ -	-$ 14,161		-$ 14,161	$ 71,231
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -	$ 12,466		$ 12,466	$ -	-$ 2,493		-$ 2,493	$ 9,973
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ 207,111		$ 207,111	$ -	-$ 13,807		-$ 13,807	$ 193,304
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 43,592	$ 412,316		$ 455,909	-$ 31,695	-$ 31,788		-$ 63,483	$ 392,426
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 7,183,004	-$ 318,521		-$ 7,501,525	$ 1,975,698	$ 162,754		$ 2,138,452	-$ 5,363,073
	etc.		$ -			$ -	$ -			$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 40,972,186**	**$ 6,483,628**	**$ -**	**$ 47,455,814**	**-$ 22,001,262**	**-$ 1,422,683**	**$ -**	**-$ 23,423,945**	**$ 24,031,869**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 40,972,186**	**$ 6,483,628**	**$ -**	**$ 47,455,814**	**-$ 22,001,262**	**-$ 1,422,683**	**$ -**	**-$ 23,423,945**	**$ 24,031,869**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**-$ 1,422,683**			
				$ 6,802,149							
				7402655							
10		Transportation		-$ 600,506							
8		Stores Equipment									

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 1,422,683

Appendix 2-BA
Fixed Asset Continuity Schedule - CGAAP

Year 2013

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: 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)	$ 476,100	$ 15,135		$ 491,235	-$ 97,936	-$ 62,933		-$ 160,870	$ 330,366
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 7,638	$ -		$ 7,638	$ -			$ -	$ 7,638
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 850,125	$ -		$ 850,125	-$ 832,112	-$ 836		-$ 832,947	$ 17,178
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,647,444	$ 286,820		$ 8,934,264	-$ 3,997,292	-$ 127,060		-$ 4,124,352	$ 4,809,912
47	1835	Overhead Conductors & Devices	$ 7,678,113	$ 192,087		$ 7,870,199	-$ 4,002,787	-$ 72,838		-$ 4,075,625	$ 3,794,574
47	1840	Underground Conduit	$ 4,396,355	$ 284,763		$ 4,681,118	-$ 1,990,199	-$ 91,038		-$ 2,081,236	$ 2,599,881
47	1845	Underground Conductors & Devices	$ 8,576,946	$ 314,373		$ 8,891,318	-$ 3,891,350	-$ 149,699		-$ 4,041,049	$ 4,850,269
47	1850	Line Transformers	$ 9,491,924	$ 347,422		$ 9,839,345	-$ 5,042,515	-$ 157,794		-$ 5,200,309	$ 4,639,036
47	1855	Services (Overhead & Underground)	$ 5,363,391	$ 146,631		$ 5,510,023	-$ 2,423,491	-$ 91,591		-$ 2,515,082	$ 2,994,941
47	1860	Meters	$ 2,445,881	$ 456		$ 2,446,338	-$ 1,595,287	-$ 74,902		-$ 1,670,189	$ 776,148
47	1860	Meters (Smart Meters)	$ 3,100,869	$ 46,475		$ 3,147,344	-$ 571,777	-$ 209,823		-$ 781,599	$ 2,365,744
N/A	1905	Land	$ 174,188			$ 174,188	$ -			$ -	$ 174,188
47	1908	Buildings & Fixtures	$ 2,400,743	$ 17,973		$ 2,418,716	-$ 937,178	-$ 37,160		-$ 974,338	$ 1,444,379
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 71,937	$ -		$ 71,937	-$ 7,194	-$ 7,194		-$ 14,387	$ 57,550
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 136,794	$ 165,763		$ 302,557	-$ 40,379	-$ 60,511		-$ 100,890	$ 201,667
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 378,015	$ 247,083	$ -	$ 625,098	-$ 38,957	-$ 52,089	$ -	-$ 91,046	$ 534,052
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 85,392	$ 22,888		$ 108,280	-$ 14,161	-$ 10,828		-$ 24,989	$ 83,291
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 12,466	$ -		$ 12,466	-$ 2,493	-$ 2,493		-$ 4,986	$ 7,479
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 207,111	$ -		$ 207,111	-$ 13,807	-$ 13,807		-$ 27,614	$ 179,497
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 455,909	$ 69,795		$ 525,704	-$ 63,483	-$ 36,441		-$ 99,925	$ 425,779
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 7,501,525	-$ 596,144		-$ 8,097,669	$ 2,138,452	$ 177,961		$ 2,316,412	-$ 5,781,256
	etc.		$ -			$ -	$ -			$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 47,455,814**	**$ 1,561,521**	**$ -**	**$ 49,017,335**	**-$ 23,423,945**	**-$ 1,081,077**	**$ -**	**-$ 24,505,022**	**$ 24,512,313**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 47,455,814**	**$ 1,561,521**	**$ -**	**$ 49,017,335**	**-$ 23,423,945**	**-$ 1,081,077**	**$ -**	**-$ 24,505,022**	**$ 24,512,313**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**-$ 1,081,077**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 1,081,077

Appendix 2-BA
Fixed Asset Continuity Schedule - CGAAP

Year 2014

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: 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)	$ 491,235	$ 96,500		$ 587,735	-$ 160,870	-$ 80,234		-$ 241,103	$ 346,632
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 7,638			$ 7,638	$ -			$ -	$ 7,638
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 850,125			$ 850,125	-$ 832,947	-$ 836		-$ 833,783	$ 16,342
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 8,934,264	$ 337,027		$ 9,271,291	-$ 4,124,352	-$ 134,549		-$ 4,258,901	$ 5,012,390
47	1835	Overhead Conductors & Devices	$ 7,870,199	$ 276,757		$ 8,146,956	-$ 4,075,625	-$ 77,450		-$ 4,153,075	$ 3,993,881
47	1840	Underground Conduit	$ 4,681,118	$ 338,922		$ 5,020,040	-$ 2,081,236	-$ 99,511		-$ 2,180,747	$ 2,839,293
47	1845	Underground Conductors & Devices	$ 8,891,318	$ 291,948		$ 9,183,266	-$ 4,041,049	-$ 156,998		-$ 4,198,047	$ 4,985,219
47	1850	Line Transformers	$ 9,839,345	$ 397,485		$ 10,236,830	-$ 5,200,309	-$ 167,731		-$ 5,368,040	$ 4,868,790
47	1855	Services (Overhead & Underground)	$ 5,510,023	$ 144,843		$ 5,654,866	-$ 2,515,082	-$ 95,212		-$ 2,610,294	$ 3,044,572
47	1860	Meters	$ 2,446,338	$ -	-$ 2,278,507	$ 167,831	-$ 1,670,189	-$ 71,895	$ 1,690,378	-$ 51,706	$ 116,125
47	1860	Meters (Smart Meters)	$ 3,147,344	$ 13,018		$ 3,160,362	-$ 781,599	-$ 210,691		-$ 992,290	$ 2,168,072
N/A	1905	Land	$ 174,188			$ 174,188	$ -			$ -	$ 174,188
47	1908	Buildings & Fixtures	$ 2,418,716	$ 100,000		$ 2,518,716	-$ 974,338	-$ 39,493		-$ 1,013,831	$ 1,504,886
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 71,937	$ 10,000		$ 81,937	-$ 14,387	-$ 8,194		-$ 22,581	$ 59,356
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 302,557	$ 19,500		$ 322,057	-$ 100,890	-$ 64,411		-$ 165,301	$ 156,756
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 625,098	$ 352,792		$ 977,891	-$ 91,046	-$ 75,422		-$ 166,468	$ 811,423
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 108,280	$ 28,000		$ 136,280	-$ 24,989	-$ 13,628		-$ 38,617	$ 97,663
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 12,466			$ 12,466	-$ 4,986	-$ 2,493		-$ 7,479	$ 4,986
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 207,111			$ 207,111	-$ 27,614	-$ 13,807		-$ 41,421	$ 165,690
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 525,704	$ 103,000		$ 628,704	-$ 99,925	-$ 43,308		-$ 143,233	$ 485,471
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 8,097,669	-$ 115,000	$ 295,793	-$ 7,916,876	$ 2,316,412	$ 181,127	-$ 130,168	$ 2,367,371	-$ 5,549,504
	etc.		$ -			$ -	$ -			$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 49,017,335**	**$ 2,394,792**	**-$ 1,982,714**	**$ 49,429,413**	**-$ 24,505,022**	**-$ 1,174,736**	**$ 1,560,210**	**-$ 24,119,548**	**$ 25,309,865**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 49,017,335**	**$ 2,394,792**	**-$ 1,982,714**	**$ 49,429,413**	**-$ 24,505,022**	**-$ 1,174,736**	**$ 1,560,210**	**-$ 24,119,548**	**$ 25,309,865**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**-$ 1,174,736**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,174,736

Appendix 2-BA
Fixed Asset Continuity Schedule - IFRS

Year **2015**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 587,735	$ 13,000		$ 600,735	-$ 241,103	-$ 65,245		-$ 306,348	$ 294,387
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 7,638			$ 7,638	$ -			$ -	$ 7,638
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 850,125			$ 850,125	-$ 833,783	-$ 836		-$ 834,619	$ 15,506
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 9,271,291	$ 294,310		$ 9,565,601	-$ 4,258,901	-$ 137,819		-$ 4,396,720	$ 5,168,881
47	1835	Overhead Conductors & Devices	$ 8,146,956	$ 241,715		$ 8,388,671	-$ 4,153,075	-$ 79,465		-$ 4,232,540	$ 4,156,131
47	1840	Underground Conduit	$ 5,020,040	$ 297,256		$ 5,317,296	-$ 2,180,747	-$ 103,226		-$ 2,283,973	$ 3,033,323
47	1845	Underground Conductors & Devices	$ 9,183,266	$ 257,119		$ 9,440,385	-$ 4,198,047	-$ 160,212		-$ 4,358,259	$ 5,082,126
47	1850	Line Transformers	$ 10,236,830	$ 347,511		$ 10,584,341	-$ 5,368,040	-$ 172,077		-$ 5,540,117	$ 5,044,224
47	1855	Services (Overhead & Underground)	$ 5,654,866	$ 126,935		$ 5,781,801	-$ 2,610,294	-$ 96,799		-$ 2,707,093	$ 3,074,708
47	1860	Meters	$ 167,831			$ 167,831	-$ 51,706	-$ 9,451		-$ 61,157	$ 106,674
47	1860	Meters (Smart Meters)	$ 3,160,362	$ 12,974		$ 3,173,336	-$ 992,290	-$ 211,556		-$ 1,203,846	$ 1,969,490
N/A	1905	Land	$ 174,188			$ 174,188	$ -			$ -	$ 174,188
47	1908	Buildings & Fixtures	$ 2,518,716	$ 100,000		$ 2,618,716	-$ 1,013,831	-$ 40,326		-$ 1,054,157	$ 1,564,559
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 81,937	$ 112,000		$ 193,937	-$ 22,581	-$ 13,794		-$ 36,375	$ 157,562
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 322,057	$ 85,000		$ 407,057	-$ 165,301	-$ 69,587		-$ 234,888	$ 172,169
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 977,891	$ 125,000		$ 1,102,891	-$ 166,468	-$ 81,672		-$ 248,140	$ 854,751
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 136,280	$ 20,000		$ 156,280	-$ 38,617	-$ 14,628		-$ 53,245	$ 103,035
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 12,466			$ 12,466	-$ 7,479	-$ 2,493		-$ 9,973	$ 2,493
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 207,111			$ 207,111	-$ 41,421	-$ 13,807		-$ 55,228	$ 151,883
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 628,704	$ 142,000		$ 770,704	-$ 143,233	-$ 47,625		-$ 190,858	$ 579,846
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 7,916,876	-$ 115,000	$ -	-$ 8,031,876	$ 2,367,371	$ 166,541		$ 2,533,912	-$ 5,497,963
	etc.		$ -			$ -	$ -			$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 49,429,413**	**$ 2,059,820**	**$ -**	**$ 51,489,233**	**-$ 24,119,548**	**-$ 1,154,077**	**$ -**	**-$ 25,273,625**	**$ 26,215,608**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 49,429,413**	**$ 2,059,820**	**$ -**	**$ 51,489,233**	**-$ 24,119,548**	**-$ 1,154,077**	**$ -**	**-$ 25,273,625**	**$ 26,215,608**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**-$ 1,154,077**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 1,154,077

Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2012

2015 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2015 Depreciation Expense [1] (h)=2013 Full Year Depreciation + ((d)*0.5)/(f)	2015 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 13,000	5.00	20.00%	$ 118,847	$ 65,244.00	$ 53,603
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -
1805	Land		-	0.00%	$ -		$ -
1808	Buildings			0.00%	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ -		$ -
1820	Distribution Station Equipment <50 kV		45.00	2.22%	$ 785	$ 836.00	-$ 51
1825	Storage Battery Equipment			0.00%	$ -		$ -
1830	Poles, Towers & Fixtures	$ 294,310	45.00	2.22%	$ 138,817	$ 137,819.00	$ 998
1835	Overhead Conductors & Devices	$ 241,715	60.00	1.67%	$ 81,346	$ 79,465.00	$ 1,881
1840	Underground Conduit	$ 297,256	40.00	2.50%	$ 100,813	$ 103,226.00	-$ 2,413
1845	Underground Conductors & Devices	$ 257,119	40.00	2.50%	$ 150,914	$ 160,212.00	-$ 9,298
1850	Line Transformers	$ 347,511	40.00	2.50%	$ 173,428	$ 172,077.00	$ 1,351
1855	Services (Overhead & Underground)	$ 126,935	40.00	2.50%	$ 97,228	$ 96,798.00	$ 430
1860	Meters		15.00	6.67%	$ 71,265	$ 9,451.00	$ 61,814
1860	Meters (Smart Meters)	$ 12,974	15.00	6.67%	$ 211,123	$ 211,555.00	-$ 432
1905	Land			0.00%	$ -		$ -
1908	Buildings & Fixtures	$ 100,000	60.00	1.67%	$ 37,594	$ 40,327.00	-$ 2,733
1910	Leasehold Improvements			0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 112,000	10.00	10.00%	$ 13,794	$ 13,794.00	-$ 0
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 85,000	5.00	20.00%	$ 91,151	$ 69,589.00	$ 21,562
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -
1930	Transportation Equipment	$ 125,000	10.00	10.00%	$ 37,372	$ 81,672.00	-$ 44,300
1935	Stores Equipment			0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 20,000	10.00	10.00%	$ 14,628	$ 14,628.00	$ 0
1945	Measurement & Testing Equipment			0.00%	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -
1955	Communications Equipment	$ -	5.00	20.00%	$ 831	$ 2,493.00	-$ 1,662
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -
1960	Miscellaneous Equipment	$ -	10.00	10.00%	$ 13,807	$ 13,807.00	$ 0
1970	Load Management Controls Customer Premises			0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -
1980	System Supervisor Equipment	$ 142,000	15.00	6.67%	$ 44,732	$ 47,625.00	-$ 2,893
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -
1995	Contributions & Grants	-$ 115,000	40.00	2.50%	-$ 184,976	-$ 166,541.00	-$ 18,435
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	**$ 2,059,820**			**$ 1,213,498**	**$ 1,154,077**	**$ 59,421**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)						
	Total Depreciation expense to be included in the test year revenue requirement				**$ 1,213,498**		

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2011 Approved	2011 Actual	2011 Actual	2012 Actual	2013 Actual[2]	Bridge Year[3] 2014	Bridge Year[3] 2014	Test Year 2015
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS
4080	**Standard Supply Service**	$ 33,130	$ 48,039	$ 48,039	$ 57,834	$ 58,337		$ 50,000	$ 37,410
4082	**Retail Services Revenues**	$ 37,386	$ 31,980	$ 31,980	$ 27,269	$ 25,111		$ 29,252	$ 29,245
4084	**STR Processing**	$ 967	$ 898	$ 898	$ 696	$ 631		$ 746	$ 746
4210	**Rent from Electric Property**	$ 305,058	$ 312,994	$ 312,994	$ 77,313	$ 34,074		$ 30,000	$ 29,994
4220	**Other Electric Revenues**	$ 69,935	$ 69,935	$ 69,935	$ 70,135	$ 69,935		$ 65,000	$ 65,000
4225	**Late Payment Charges**	$ 138,817	$ 122,874	$ 122,874	$ 118,049	$ 130,857		$ 120,000	$ 120,000
4235	**Specific Service Charges**	$ 163,834	$ 147,745	$ 147,745	$ 165,278	$ 168,396		$ 149,000	$ 149,000
4355	**Gain on Disposal**		$ -	$ -					
4375	**Revenues from Non Rate-Regulated Utility Operations**	$ 58,374	$ 343,085	$ 343,085	$ 1,064,456	$ 1,458,239		$ 342,000	$ 354,000
4380	**Expenses from Non Rate-Regulated Utility Operations**								-$ 322,751
4390	**Miscellaneous Non-Operating Income**	$ 41,000	$ 41,000	$ 41,000	$ 71,848	$ 129,922		$ 60,000	$ 15,000
Specific Service Charges		$ 163,834	$ 147,745	$ 147,745	$ 165,278	$ 168,396	$ -	$ 149,000	$ 149,000
Late Payment Charges		$ 138,817	$ 122,874	$ 122,874	$ 118,049	$ 130,857	$ -	$ 120,000	$ 120,000
Other Operating Revenues		$ 545,850	$ 847,932	$ 847,932	$ 1,369,551	$ 1,776,249	$ -	$ 576,998	$ 531,395
Other Income or Deductions		-$ 39,559	-$ 200,025	-$ 200,025	-$ 938,566	-$ 1,124,370		-$ 292,256	-$ 322,751
Total		$ 808,942	$ 918,526	$ 918,526	$ 714,312	$ 951,132	$ -	$ 553,742	**$ 477,644**

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4405 - Interest and Dividend Income

		2011 Actual	2011 Actual	2012 Actual	2013 Actual[2]	Bridge Year[3] 2014	Bridge Year[3] 2014	Test Year 2015
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS
Short-term Investment Interest		$ -						
Bank Deposit Interest		$ 6,859	$ 6,859	$ 5,155	$ 4,423	$ 4,000	$ 4,000	$ 4,000
Miscellaneous Interest Revenue - RSVA		$ 64,512	$ 64,512	$ 77,957	$ 43,060	$ 31,000	$ 31,000	$ 31,000
etc.[1]		$ -	$ -	$ -	$ -		$ -	
Total		$ 71,371	$ 71,371	$ 83,112	$ 47,483	$ 35,000	$ 35,000	**$ 35,000**

TOTAL **$ 512,644**

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year
Reporting Basis						
Operations	$ 493,406	$ 558,853	$ 958,213	$ 868,543	$ 925,270	$ 966,891
Maintenance	$ 423,276	$ 364,438	$ 324,575	$ 274,855	$ 333,832	$ 330,032
SubTotal	**$ 916,682**	**$ 923,291**	**$ 1,282,788**	**$ 1,143,398**	**$ 1,259,102**	**$ 1,296,923**
%Change (year over year)			38.9%	-10.9%	10.1%	3.0%
%Change (Test Year vs Last Rebasing Year - Actual)						40.5%
Billing and Collecting	$ 1,133,130	$ 982,501	$ 1,039,175	$ 869,044	$ 938,833	$ 955,158
Community Relations	$ 19,513	$ 2,684	$ 32,390	$ -	$ -	$ -
Administrative and General	$ 1,502,109	$ 1,832,734	$ 2,691,486	$ 1,998,931	$ 2,259,284	$ 2,237,919
SubTotal	**$ 2,654,752**	**$ 2,817,919**	**$ 3,763,051**	**$ 2,867,975**	**$ 3,198,117**	**$ 3,193,077**
%Change (year over year)			33.5%	-23.8%	11.5%	-0.2%
%Change (Test Year vs Last Rebasing Year - Actual)						13.3%
Total	**$ 3,571,434**	**$ 3,741,210**	**$ 5,045,839**	**$ 4,011,373**	**$ 4,457,219**	**$ 4,490,000**
%Change (year over year)			34.9%	-20.5%	11.1%	0.7%

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year
Operations	$ 493,406	$ 558,853	$ 958,213	$ 868,543	$ 925,270	$ 966,891
Maintenance	$ 423,276	$ 364,438	$ 324,575	$ 274,855	$ 333,832	$ 330,032
Billing and Collecting	$ 1,133,130	$ 982,501	$ 1,039,175	$ 869,044	$ 938,833	$ 955,158
Community Relations	$ 19,513	$ 2,684	$ 32,390	$ -	$ -	$ -
Administrative and General	$ 1,502,109	$ 1,832,734	$ 2,691,486	$ 1,998,931	$ 2,259,284	$ 2,237,919
Total	**$ 3,571,434**	**$ 3,741,210**	**$ 5,045,839**	**$ 4,011,373**	**$ 4,457,219**	**$ 4,490,000**
%Change (year over year)			34.9%	-20.5%	11.1%	0.7%

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	Variance 2011 BA – 2011 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Bridge Year	Variance 2014 Bridge vs. 2013 Actuals	2015 Test Year	Variance 2015 Test vs. 2014 Bridge
Operations	$ 493,406	$ 558,853	-$ 65,447	$ 958,213	$ 399,360	$ 868,543	-$ 89,670	$ 925,270	$ 56,727	$ 966,891	$ 41,621
Maintenance	$ 423,276	$ 364,438	$ 58,838	$ 324,575	-$ 39,863	$ 274,855	-$ 49,720	$ 333,832	$ 58,977	$ 330,032	-$ 3,800
Billing and Collecting	$ 1,133,130	$ 982,501	$ 150,629	$ 1,039,175	$ 56,674	$ 869,044	-$ 170,131	$ 938,833	$ 69,789	$ 955,158	$ 16,325
Community Relations	$ 19,513	$ 2,684	$ 16,829	$ 32,390	$ 29,706	$ -	-$ 32,390	$ -	$ -	$ -	$ -
Administrative and General	$ 1,502,109	$ 1,832,734	-$ 330,625	$ 2,691,486	$ 858,752	$ 1,998,931	-$ 692,555	$ 2,259,284	$ 260,353	$ 2,237,919	-$ 21,365
Total OM&A Expenses	$ 3,571,434	$ 3,741,210	-$ 169,776	$ 5,045,839	$ 1,304,629	$ 4,011,373	-$ 1,034,466	$ 4,457,219	$ 445,846	$ 4,490,000	$ 32,781
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	$ 3,571,434	$ 3,741,210	-$ 169,776	$ 5,045,839	$ 1,304,629	$ 4,011,373	-$ 1,034,466	$ 4,457,219	$ 445,846	$ 4,490,000	$ 32,781
Variance from previous year				$ 1,304,629		-$ 1,034,466		$ 445,846		$ 32,781	
Percent change (year over year)				35%		-21%		11%		1%	
Percent Change: Test year vs. Most Current Actual						11.93%					
Simple average of % variance for all years						20.01%					7%
Compound Annual Growth Rate for all years											3.7%
Compound Growth Rate (2013 Actuals vs. 2011 Actuals)						2.35%					

Appendix 2-OA
Capital Structure and Cost of Capital

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

Year: 2011

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$13,371,497	5.60%	$748,804
2	Short-term Debt	4.00%	(1)	$955,107	2.46%	$23,496
3	**Total Debt**	60.0%		$14,326,604	5.39%	$772,299
	Equity					
4	Common Equity	40.00%		$9,551,069	9.58%	$914,992
5	Preferred Shares			$0		$ -
6	**Total Equity**	40.0%		$9,551,069	9.58%	$914,992
7	**Total**	100.0%		$23,877,673	7.07%	$1,687,292

Appendix 2-OA
Capital Structure and Cost of Capital

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%		$16,414,371	4.67%	$766,551
2	Short-term Debt	4.00%	(1)	$1,172,455	2.11%	$24,739
3	**Total Debt**	60.0%		$17,586,826	4.50%	$791,290
	Equity					
4	Common Equity	40.00%		$11,724,551	9.36%	$1,097,418
5	Preferred Shares	0.00%		$0		$ -
6	**Total Equity**	40.0%		$11,724,551	9.36%	$1,097,418
7	**Total**	100.0%		$29,311,377	6.44%	$1,888,708

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	$4,225,650	60.43%	$ 4,797,532	63.51%
GS < 50 kW	$1,047,217	14.98%	$ 1,224,051	16.20%
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$1,394,746	19.95%	$ 1,299,716	17.21%
GS > xxx kW, if applicable		0.00%		0.00%
Large User, if applicable		0.00%		0.00%
Street Lighting	$ 317,527	4.54%	$ 229,003	3.03%
Sentinel Lighting	$ 7,342	0.11%	$ 3,374	0.04%
Unmetered Scattered Load (USL)				
Other class, if applicable				
Embedded distributor class				
Total	$6,992,482	100.00%	$ 7,553,676	100.00%

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C L.F. X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 4,388,175	$ 4,614,827	$ 4,614,827	$ 354,826
GS < 50 kW	$ 1,074,096	$ 1,129,574	$ 1,129,574	$ 75,450
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$ 1,026,602	$ 1,079,627	$ 1,080,768	$ 74,092
GS > xxx kW, if applicable				
Large User, if applicable				
Street Lighting	$ 201,532	$ 211,941	$ 211,941	$ 8,150
Sentinel Lighting	$ 4,814	$ 5,063	$ 3,923	$ 126
Unmetered Scattered Load (USL)				
Other class, if applicable				
Embedded distributor class				
Total	$ 6,695,218	$ 7,041,032	$ 7,041,033	$ 512,644

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

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2011	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	108.62	103.59	103.59	85 - 115
GS < 50 kW	101.31	98.45	98.45	80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	93.40	88.77	88.85	80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	11.47	96.11	96.11	70 - 120
Sentinel Lighting	32.98	153.79	120.00	80 - 120
Unmetered Scattered Load (USL)				80 - 120
Other class, if applicable				
Embedded distributor class				

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

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2015	2016	2017	
	%	%	%	%
Residential	103.59			85 - 115
GS < 50 kW	98.45			80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	88.85			80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	96.11			70 - 120
Sentinel Lighting	120.00			80 - 120
Unmetered Scattered Load (USL)				80 - 120
Other class, if applicable				0
				0
Embedded distributor class				

Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	14,973.00	15,120.00	15,046.50	120,603,908		$ 14.25	$ 0.0168		$ 4,599,097.15	$ 4,614,827		$ 4,614,827	$ 15,730
GS < 50 kW	Customers	1,728.00	1,737.00	1,732.50	40,656,676		$ 23.26	$ 0.0159		$ 1,130,016.54	$ 1,129,574	$ 889	$ 1,130,463	$ 446
GS > 50 to 4,999 kW	Customers	143.00	144.00	143.50	116,608,841	297,360	$ 72.31		$ 3.4718	$ 1,156,892.27	$ 1,080,768	$ 76,554	$ 1,157,322	$ 430
Streetlighting	Connections	4,918.00	4,918.00	4,918.00	3,118,174	8,629	$ 3.79		$ 0.0350	$ 223,972.66	$ 211,941		$ 211,941	-$ 12,032
Sentinel Lighting	Connections	52.00	52.00	52.00	22,839	174	$ 5.00		$ 5.6830	$ 4,108.84	$ 5,189		$ 5,189	$ 1,080
				-						$ -			$ -	$ -
Total										**$ 7,114,087.46**	**$ 7,042,299**	**$ 77,443**	**$ 7,119,742**	**$ 5,655**

Note

1 The class specific revenue requirements in column N must be the amounts used in the final rate design process. The total of column N should equate to the proposed base revenue requirement.

2 Rates should be entered with the number of decimal places that will show on the Tariff of Rates and Charges.

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 800 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 11.5300	1	$ 11.53	$ 14.2500	1	$ 14.25	$ 2.72	23.59%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0160	800	$ 12.80	$ 0.0168	800	$ 13.44	$ 0.64	5.00%
Rate Rider for Recovery of Smart	Monthly	$ 2.0200	1	$ 2.02	$ -	1	$ -	-$ 2.02	-100.00%
Rate Rider for LRAM/SSM	kWh	$ -	800	$ -	$ 0.0001	800	$ 0.04	$ 0.04	
Stranded Meter Rate Rider	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Rate Rider for Smart Metering En	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Rate Rider for Application of Tax (	kWh	-$ 0.0001	800	-$ 0.08	$ -	800	$ -	$ 0.08	-100.00%
Stranded Meter Recovery Rate Ri	Monthly	$ -	1	$ -	$ 0.3700	1	$ 0.37	$ 0.37	
Sub-Total A				$ 27.06			$ 28.89	**$ 1.83**	**6.76%**
Rate Rider for Deferral/Variance Account Disposition (2014) - effective until April 30, 2015	kWh	-$ 0.0064	800	-$ 5.12	-$ 0.0064	800	-$ 5.12	$ -	
Rate Rider for Deferral/Variance Account Disposition (2015) - Effective until Dec 31, 2015	kWh	$ -	800	$ -	-$ 0.0026	800	-$ 2.08	-$ 2.08	
Low Voltage Service Charge	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 21.94**			**$ 21.69**	**-$ 0.25**	**-1.14%**
RTSR - Network	kWh	$ 0.0070	828	$ 5.80	$ 0.0075	831	$ 6.24	$ 0.44	7.59%
RTSR - Line and Transformation Connection	kWh	$ 0.0052	828	$ 4.31	$ 0.0058	831	$ 4.82	$ 0.52	12.01%
Sub-Total C - Delivery (including Sub-Total B)				**$ 32.04**			**$ 32.75**	**$ 0.71**	**2.21%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	828	$ 4.31	$ 0.0044	831	$ 3.66	-$ 0.65	-15.03%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	828	$ 1.08	$ 0.0013	831	$ 1.08	$ 0.00	0.42%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0880	228	$ 20.06	$ 0.0880	231	$ 20.37	$ 0.31	1.52%
TOU - Off Peak	kWh	$ 0.0650	530	$ 34.44	$ 0.0650	532	$ 34.59	$ 0.14	0.42%
TOU - Mid Peak	kWh	$ 0.1000	149	$ 14.90	$ 0.1000	150	$ 14.97	$ 0.06	0.42%
TOU - On Peak	kWh	$ 0.1170	149	$ 17.44	$ 0.1170	150	$ 17.51	$ 0.07	0.42%
Total Bill on RPP (before Taxes)				**$ 108.09**			**$ 108.46**	**$ 0.37**	**0.34%**
HST		13%		$ 14.05	13%		$ 14.10	$ 0.05	0.34%
Total Bill (including HST)				$ 122.14			$ 122.56	$ 0.42	0.34%
Ontario Clean Energy Benefit 1				-$ 12.21			-$ 12.26	-$ 0.05	0.41%
Total Bill on RPP (including OCEB)				**$ 109.93**			**$ 110.30**	**$ 0.37**	**0.34%**
Total Bill on TOU (before Taxes)				**$ 109.81**			**$ 110.15**	**$ 0.34**	**0.31%**
HST		13%		$ 14.28	13%		$ 14.32	$ 0.04	0.31%
Total Bill (including HST)				$ 124.09			$ 124.47	$ 0.39	0.31%
Ontario Clean Energy Benefit 1				-$ 12.41			-$ 12.45	-$ 0.04	0.32%
Total Bill on TOU (including OCEB)				**$ 111.68**			**$ 112.02**	**$ 0.35**	**0.31%**

Loss Factor (%) 3.50% (current) 3.93% (proposed)

Appendix 2-W
Bill Impacts

Customer Class: **General Service < 50 kW**

Consumption 2000 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 17.4700	1	$ 17.47	$ 23.2600	1	$ 23.26	$ 5.79	33.14%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0151	2000	$ 30.20	$ 0.0159	2000	$ 31.80	$ 1.60	5.30%
Rate Rider for Recovery of Smart	Monthly	$ 4.6500	1	$ 4.65	$ -	1	$ -	-$ 4.65	-100.00%
Rate Rider for LRAM/SSM	kWh	$ -	2000	$ -	$ 0.0007	2000	$ 1.40	$ 1.40	
Stranded Meter Rate Rider	kWh	$ -	2000	$ -	$ -	2000	$ -	$ -	
Rate Rider for Smart Metering En	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Rate Rider for Application of Tax	kWh	-$ 0.0001	2000	-$ 0.20	$ -	2000	$ -	$ 0.20	-100.00%
Stranded Meter Recovery Rate Ri	Monthly	$ -	1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
Sub-Total A				$ 52.91			$ 58.04	**$ 5.13**	**9.70%**
Rate Rider for Deferral/Variance Account Disposition (2014) - effective until April 30, 2015	kWh	-$ 0.0063	2000	-$ 12.60	-$ 0.0063	2000	-$ 12.60	$ -	
Rate Rider for Deferral/Variance Account Disposition (2015) - Effective until Dec 31, 2015	kWh	$ -	2000	$ -	-$ 0.0026	2000	-$ 5.20	-$ 5.20	
Low Voltage Service Charge	kWh	$ -	2000	$ -	$ -	2000	$ -	$ -	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 40.31**			**$ 40.24**	**-$ 0.07**	**-0.17%**
RTSR - Network	kWh	$ 0.0069	2070	$ 14.28	$ 0.0074	2079	$ 15.38	$ 1.10	7.70%
RTSR - Line and Transformation Connection	kWh	$ 0.0048	2070	$ 9.94	$ 0.0054	2079	$ 11.29	$ 1.35	13.60%
Sub-Total C - Delivery (including Sub-Total B)				**$ 64.53**			**$ 66.91**	**$ 2.38**	**3.69%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	2070	$ 10.76	$ 0.0044	2079	$ 9.15	-$ 1.62	-15.03%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	2070	$ 2.69	$ 0.0013	2079	$ 2.70	$ 0.01	0.42%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0750	750	$ 56.25	$ 0.0750	750	$ 56.25	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0880	1320	$ 116.16	$ 0.0880	1329	$ 116.92	$ 0.76	0.66%
TOU - Off Peak	kWh	$ 0.0650	1325	$ 86.11	$ 0.0650	1330	$ 86.47	$ 0.36	0.42%
TOU - Mid Peak	kWh	$ 0.1000	373	$ 37.26	$ 0.1000	374	$ 37.42	$ 0.16	0.42%
TOU - On Peak	kWh	$ 0.1170	373	$ 43.59	$ 0.1170	374	$ 43.78	$ 0.18	0.42%
Total Bill on RPP (before Taxes)				**$ 264.39**			**$ 265.93**	**$ 1.54**	**0.58%**
HST		13%		$ 34.37	13%		$ 34.57	$ 0.20	0.58%
Total Bill (including HST)				$ 298.77			$ 300.50	$ 1.74	0.58%
Ontario Clean Energy Benefit 1				-$ 29.88			-$ 30.05	-$ 0.17	0.57%
Total Bill on RPP (including OCEB)				**$ 268.89**			**$ 270.45**	**$ 1.57**	**0.58%**
Total Bill on TOU (before Taxes)				**$ 258.95**			**$ 260.42**	**$ 1.47**	**0.57%**
HST		13%		$ 33.66	13%		$ 33.86	$ 0.19	0.57%
Total Bill (including HST)				$ 292.61			$ 294.28	$ 1.67	0.57%
Ontario Clean Energy Benefit 1				-$ 29.26			-$ 29.43	-$ 0.17	0.58%
Total Bill on TOU (including OCEB)				**$ 263.35**			**$ 264.85**	**$ 1.50**	**0.57%**

Loss Factor (%) 3.50% 3.93%

Appendix 2-W
Bill Impacts

Customer Class: **General Service > 50**

Consumption 40000 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 72.3100	1	$ 72.31	$ 72.3100	1	$ 72.31	$ -	
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 3.2366	100	$ 323.66	$ 3.4718	100	$ 347.18	$ 23.52	7.27%
Rate Rider for Recovery of Smart	Monthly	$ 9.1200	1	$ 9.12	$ -	1	$ -	-$ 9.12	-100.00%
Rate Rider for LRAM/SSM	kW	$ -	100	$ -	-$ 0.0015	100	-$ 0.15	-$ 0.15	
Stranded Meter Rate Rider	kWh	$ -	40000	$ -	$ -	40000	$ -	$ -	
Rate Rider for Smart Metering En	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Application of Tax	kW	-$ 0.0093	100	-$ 0.93	$ -	100	$ -	$ 0.93	-100.00%
Stranded Meter Recovery Rate Ri	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 404.16			$ 419.34	**$ 15.18**	**3.76%**
Rate Rider for Deferral/Variance Account Disposition (2014) - effective until April 30, 2015	kW	-$ 2.3802	100	-$ 238.02	-$ 2.3802	100	-$ 238.02	$ -	
Rate Rider for Deferral/Variance Account Disposition (2015) - Effective until Dec 31, 2015	kW	$ -	100	$ -	-$ 1.0315	100	-$ 103.15	-$ 103.15	
Low Voltage Service Charge	kWh	$ -	40000	$ -	$ -	40000	$ -	$ -	
Smart Meter Entity Charge						40000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 166.14**			**$ 78.17**	**-$ 87.97**	**-52.95%**
RTSR - Network	kW	$ 2.7638	104	$ 286.05	$ 2.9672	104	$ 308.39	$ 22.34	7.81%
RTSR - Line and Transformation Connection	kW	$ 1.9761	104	$ 204.53	$ 2.2033	104	$ 229.00	$ 24.47	11.97%
Sub-Total C - Delivery (including Sub-Total B)				**$ 656.72**			**$ 615.56**	**-$ 41.16**	**-6.27%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	41400	$ 215.28	$ 0.0044	41574	$ 182.92	-$ 32.36	-15.03%
Rural and Remote Rate	kWh	$ 0.0013	41400	$ 53.82	$ 0.0013	41574	$ 54.05	$ 0.23	0.42%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	40000	$ 280.00	$ 0.0070	40000	$ 280.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0750	750	$ 56.25	$ 0.0750	750	$ 56.25	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0880	40650	$ 3,577.20	$ 0.0880	40824	$ 3,592.49	$ 15.29	0.43%
TOU - Off Peak	kWh	$ 0.0650	26496	$ 1,722.24	$ 0.0650	26607	$ 1,729.47	$ 7.23	0.42%
TOU - Mid Peak	kWh	$ 0.1000	7452	$ 745.20	$ 0.1000	7483	$ 748.33	$ 3.13	0.42%
TOU - On Peak	kWh	$ 0.1170	7452	$ 871.88	$ 0.1170	7483	$ 875.54	$ 3.66	0.42%
Total Bill on RPP (before Taxes)				**$ 4,839.27**			**$ 4,781.27**	**-$ 58.00**	**-1.20%**
HST		13%		$ 629.11	13%		$ 621.57	-$ 7.54	-1.20%
Total Bill (including HST)				$ 5,468.37			$ 5,402.84	-$ 65.54	-1.20%
Ontario Clean Energy Benefit 1				-$ 546.84			-$ 540.28	$ 6.56	-1.20%
Total Bill on RPP (including OCEB)				**$ 4,921.53**			**$ 4,862.56**	**-$ 58.98**	**-1.20%**
Total Bill on TOU (before Taxes)				**$ 4,545.14**			**$ 4,485.87**	**-$ 59.27**	**-1.30%**
HST		13%		$ 590.87	13%		$ 583.16	-$ 7.71	-1.30%
Total Bill (including HST)				$ 5,136.01			$ 5,069.03	-$ 66.98	-1.30%
Ontario Clean Energy Benefit 1				-$ 513.60			-$ 506.90	$ 6.70	-1.30%
Total Bill on TOU (including OCEB)				**$ 4,622.41**			**$ 4,562.13**	**-$ 60.28**	**-1.30%**

Loss Factor (%) Current: 3.50% Proposed: 3.93%

Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Lighting**

Consumption 36.60096154 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 5.7700	1	$ 5.77	$ 4.7000	1	$ 4.70	-$ 1.07	-18.54%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 6.9740	0.27885	$ 1.94	$ 5.6830	0.27885	$ 1.58	-$ 0.36	-18.51%
Rate Rider for Recovery of Smart	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for LRAM/SSM	kW	$ -	0.27885	$ -	$ -	0.27885	$ -	$ -	
Stranded Meter Rate Rider	kWh	$ -	36.601	$ -	$ -	36.601	$ -	$ -	
Rate Rider for Smart Metering En	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Application of Tax	kW	-$ 0.0727	0.27885	-$ 0.02	$ -	0.27885	$ -	$ 0.02	-100.00%
Stranded Meter Recovery Rate Ri	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 7.69			$ 6.28	**-$ 1.41**	**-18.32%**
Rate Rider for Deferral/Variance Account Disposition (2014) - effective until April 30, 2015	kW	-$ 2.5325	0.27885	-$ 0.71	-$ 2.5325	0.27885	-$ 0.71	$ -	
Rate Rider for Deferral/Variance Account Disposition (2015) - Effective until Dec 31, 2015	kW	$ -	0.27885	$ -	-$ 0.3453	0.27885	-$ 0.10	-$ 0.10	
Low Voltage Service Charge	kWh	$ -	36.601	$ -	$ -	36.601	$ -	$ -	
Smart Meter Entity Charge						36.601	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.99**			**$ 5.48**	**-$ 1.51**	**-21.55%**
RTSR - Network	kW	$ 1.7373	0	$ 0.50	$ 1.8652	0	$ 0.54	$ 0.04	7.81%
RTSR - Line and Transformation Connection	kW	$ 1.2413	0	$ 0.36	$ 1.3840	0	$ 0.40	$ 0.04	11.96%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.85**			**$ 6.42**	**-$ 1.42**	**-18.14%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	38	$ 0.20	$ 0.0044	38	$ 0.17	-$ 0.03	-15.03%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	38	$ 0.05	$ 0.0013	38	$ 0.05	$ 0.00	0.42%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	37	$ 0.26	$ 0.0070	37	$ 0.26	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0750	38	$ 2.84	$ 0.0750	38	$ 2.85	$ 0.01	0.42%
Energy - RPP - Tier 2	kWh	$ 0.0880		$ -	$ 0.0880		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0650	24	$ 1.58	$ 0.0650	24	$ 1.58	$ 0.01	0.42%
TOU - Mid Peak	kWh	$ 0.1000	7	$ 0.68	$ 0.1000	7	$ 0.68	$ 0.00	0.42%
TOU - On Peak	kWh	$ 0.1170	7	$ 0.80	$ 0.1170	7	$ 0.80	$ 0.00	0.42%
Total Bill on RPP (before Taxes)				**$ 11.19**			**$ 9.75**	**-$ 1.44**	**-12.88%**
HST		13%		$ 1.45	13%		$ 1.27	-$ 0.19	-12.88%
Total Bill (including HST)				$ 12.65			$ 11.02	-$ 1.63	-12.88%
Ontario Clean Energy Benefit 1				-$ 1.26			-$ 1.10	$ 0.16	-12.70%
Total Bill on RPP (including OCEB)				**$ 11.39**			**$ 9.92**	**-$ 1.47**	**-12.90%**
Total Bill on TOU (before Taxes)				**$ 11.41**			**$ 9.97**	**-$ 1.44**	**-12.63%**
HST		13%		$ 1.48	13%		$ 1.30	-$ 0.19	-12.63%
Total Bill (including HST)				$ 12.89			$ 11.26	-$ 1.63	-12.63%
Ontario Clean Energy Benefit 1				-$ 1.29			-$ 1.13	$ 0.16	-12.40%
Total Bill on TOU (including OCEB)				**$ 11.60**			**$ 10.13**	**-$ 1.47**	**-12.66%**
Loss Factor (%)		3.50%			3.93%				

Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption 52.83607835 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 3.4100	1	$ 3.41	$ 3.5900	1	$ 3.59	$ 0.18	5.28%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 0.0333	0.14621	$ 0.00	$ 0.0350	0.14621	$ 0.01	$ 0.00	5.11%
Rate Rider for Recovery of Smart	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for LRAM/SSM	kW	$ -	0.14621	$ -	$ -	0.14621	$ -	$ -	
Stranded Meter Rate Rider	kWh	$ -	52.8361	$ -	$ -	52.8361	$ -	$ -	
Rate Rider for Smart Metering En	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for Application of Tax (	kW	-$ 0.0576	0.14621	-$ 0.01	$ -	0.14621	$ -	$ 0.01	-100.00%
Stranded Meter Recovery Rate Ri	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 3.41			$ 3.60	**$ 0.19**	**5.54%**
Rate Rider for Deferral/Variance Account Disposition (2014) - effective until April 30, 2015	kW	-$ 2.3082	0.14621	-$ 0.34	-$ 2.3082	0.14621	-$ 0.34	$ -	
Rate Rider for	kW	$ -	0.14621	$ -	-$ 0.9505	0.14621	-$ 0.14	-$ 0.14	
Low Voltage Service Charge	kWh	$ -	52.8361	$ -	$ -	52.8361	$ -	$ -	
Smart Meter Entity Charge						52.8361	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 3.07**			**$ 3.12**	**$ 0.05**	**1.62%**
RTSR - Network	kW	$ 2.1313	0	$ 0.32	$ 2.2882	0	$ 0.35	$ 0.03	7.81%
RTSR - Line and Transformation Connection	kW	$ 1.5236	0	$ 0.23	$ 1.6988	0	$ 0.26	$ 0.03	11.97%
Sub-Total C - Delivery				**$ 3.62**			**$ 3.72**	**$ 0.10**	**2.83%**
Wholesale Market Service	kWh	$ 0.0052	55	$ 0.28	$ 0.0044	55	$ 0.24	-$ 0.04	-15.03%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	55	$ 0.07	$ 0.0013	55	$ 0.07	$ 0.00	0.42%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	53	$ 0.37	$ 0.0070	53	$ 0.37	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0750	55	$ 4.10	$ 0.0750	55	$ 4.12	$ 0.02	0.42%
Energy - RPP - Tier 2	kWh	$ 0.0880		$ -	$ 0.0880		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0650	35	$ 2.27	$ 0.0650	35	$ 2.28	$ 0.01	0.42%
TOU - Mid Peak	kWh	$ 0.1000	10	$ 0.98	$ 0.1000	10	$ 0.99	$ 0.00	0.42%
TOU - On Peak	kWh	$ 0.1170	10	$ 1.15	$ 0.1170	10	$ 1.16	$ 0.00	0.42%
Total Bill on RPP (before Taxes)				**$ 8.45**			**$ 8.53**	**$ 0.08**	**0.91%**
HST		13%		$ 1.10	13%		$ 1.11	$ 0.01	0.91%
Total Bill (including HST)				$ 9.55			$ 9.63	$ 0.09	0.91%
Ontario Clean Energy Benefit 1				-$ 0.95			-$ 0.96	-$ 0.01	1.05%
Total Bill on RPP (including OCEB)				**$ 8.60**			**$ 8.67**	**$ 0.08**	**0.90%**
Total Bill on TOU (before Taxes)				**$ 8.76**			**$ 8.84**	**$ 0.08**	**0.90%**
HST		13%		$ 1.14	13%		$ 1.15	$ 0.01	0.90%
Total Bill (including HST)				$ 9.90			$ 9.99	$ 0.09	0.90%
Ontario Clean Energy Benefit 1				-$ 0.99			-$ 1.00	-$ 0.01	1.01%
Total Bill on TOU (including OCEB)				**$ 8.91**			**$ 8.99**	**$ 0.08**	**0.88%**

Loss Factor (%) 3.50% (Current Board-Approved) 3.93% (Proposed)