Ontario Energy
Board

Commission de l'énergie
de l'Ontario

Ontario

EB-2012-0162

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 PUC Distribution Inc. for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective July 1, 2013.

BEFORE: **Cathy Spoel**
Presiding Member

Jerry Farrell
Member

DECISION AND RATE ORDER
July 4, 2013

PUC Distribution Inc. ("PUC") filed an application with the Ontario Energy Board (the "Board") on December 5, 2012 under section 78 of the *Ontario Energy Board Act, 1998* seeking approval for changes to the rates that PUC charges for electricity distribution to be effective May 1, 2013.

The Board issued a Notice of Application and Hearing dated December 21, 2012. The Energy Probe Research Foundation ("Energy Probe"), School Energy Coalition ("SEC") and Vulnerable Energy Consumers Coalition ("VECC") applied for and were granted intervenor status and cost eligibility.

In accordance with Procedural Order No. 1, issued on January 18, 2013, the Board made provision for written interrogatories.

In Procedural Order No. 2 and Procedural Order No. 3, issued on February 26, 2013 and March 28, 2013 respectively, the Board extended the deadline for PUC's interrogatory responses.

On April 4, 2013, PUC filed responses to the interrogatories of Energy Probe, SEC, VECC and Board staff.

On April 19, 2013, the Board issued Procedural Order No.4 and Order for Interim Rates making PUC's rates interim and establishing dates for a supplemental round of written interrogatories and a settlement conference.

A settlement conference was held on May 21 and 22, 2013. PUC, Energy Probe, SEC and VECC are the parties (collectively, the "Parties") to the Settlement Agreement. PUC, on behalf of the Parties, filed a proposed Settlement Agreement on June 14, 2013.

The Settlement Agreement is included as Appendix A to this Decision. In the Settlement Agreement, the Parties agreed to settle all matters. The Parties also filed material supporting a draft Rate Order and the resulting Tariff of Rates and Changes and indicated that it has the support of all Parties. On behalf of the Parties, PUC suggested that the Board may wish to forego the formal draft Rate Order process, if the Board found that it would be efficient to do so.

The Board notes that the Parties have agreed to ring-fence an average amount of $100,000 per year, totalling $400,000, of PUC's OM&A monies and/or revenue requirement on capital expenditures, to be spent in the period from the effective date of the rates arising out of this Application through April 30, 2017 on furthering PUC's productivity and efficiency. The OM&A expenditures are included in, and not in addition to, the Board-approved OM&A amount, of $9,952,946. Any amounts of the total $400,000 not spent on productivity- and efficiency-related studies and/or projects will be returned to customers by way of an appropriate credit rate rider to be determined at the time of PUC's next rebasing rate application.

The Board has reviewed the Settlement Agreement and finds that the resultant rates and other charges would be just and reasonable if the Board were to approve the Settlement Agreement as filed. The Board accordingly does so without, however, making any findings on the individual provisions of the Settlement Agreement, except those relating to the creation of the proposed 'Productivity Initiatives Variance Account'. The Board finds that the creation of this account is an innovative means of complementing PUC's measures to enhance its productivity and accordingly specifically approves this aspect of the Settlement Agreement.

The Board has also reviewed the information provided in support of the proposed Tariff of Rates and Charges. The Board is satisfied that the Tariff of Rates and Charges accurately reflects the Settlement Agreement.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges for PUC Distribution Inc. set out in Appendix B of this Decision and Rate Order is approved effective July 1, 2013 for electricity consumed or estimated to have been consumed on and after July 1, 2013. PUC Distribution Inc. shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

Cost Awards

The Board may grant cost awards to eligible parties pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board’s *Practice Direction on Cost Awards*. The maximum hourly rates set out in the Board’s Cost Awards Tariff will also be applied.

1. Energy Probe Research Foundation, School Energy Coalition and Vulnerable Energy Consumers Coalition shall file with the Board and forward to PUC Distribution Inc. their respective cost claims within **7 days** from the date of this Decision and Rate Order.

2. PUC Distribution Inc. shall file with the Board and forward to Energy Probe Research Foundation, School Energy Coalition and Vulnerable Energy Consumers Coalition any objections to the claimed costs within **17 days** from the date of this Decision and Rate Order.

3. Energy Probe Research Foundation, School Energy Coalition and Vulnerable Energy Consumers Coalition shall file with the Board and forward to PUC

Distribution Inc. any responses to any objections for cost claims within **24 days** of the date of this Decision and Rate Order.

4. PUC Distribution Inc. shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings with the Board must quote the file number EB-2012-0162 and be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca.

DATED at Toronto, July 4, 2013

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

TO DECISION AND RATE ORDER

PUC Distribution Inc.

EB-2012-0162

SETTLEMENT AGREEMENT

EB- 2012-0162

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 PUC Distribution Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

PUC DISTRIBUTION INC. ("PUCDI")

PROPOSED SETTLEMENT AGREEMENT

FILED: JUNE 14, 2013

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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 PUC Distribution Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

PUC DISTRIBUTION INC. ("PUCDI")

PROPOSED SETTLEMENT AGREEMENT

FILED: JUNE 14, 2013

INTRODUCTION:

PUCDI carries on the business of distributing electricity within the City of Sault Ste. Marie (with the exception of all or part of five municipal addresses as listed on its distribution license), Township of Prince, Rankin Reserve, and the Township of Dennis (Concession 3, 4 and 5).

PUCDI filed a complete application with the Ontario Energy Board (the "Board") on December 5, 2012 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 PUCDI charges for electricity distribution, to be effective May 1, 2013 (the "Application"). The Board assigned the Application file number EB-2012-0162.

Three Parties requested and were granted intervenor status: Energy Probe Research Foundation ("Energy Probe" or "EP"), the School Energy Coalition ("SEC") and the Vulnerable Energy Consumers' Coalition ("VECC"). These Parties are referred to collectively as the "Intervenors".

In Procedural Order No. 1, issued on January 18, 2013, the Board approved the Intervenors in this proceeding, set dates for interrogatories and interrogatory responses and made its determination regarding the cost eligibility of the Intervenors.

In Procedural Order No. 2 and Procedural Order No. 3, issued on February 26, 2013 and March 28, 2013 respectively, the Board extended the deadline for PUCDI's interrogatory responses.

In the Board's Procedural Order No 4 and Order for Interim Rates, issued on April 19, 2013, the Board made PUCDI's current rates interim, and set dates for supplemental interrogatories and responses; a Settlement Conference (May 21, 2013, continuing May 22, 2013 if necessary); and, the filing of any Settlement Proposal arising out of the Settlement Conference (May 31, 2013). There is no Board-approved Issues List for this proceeding.

The evidence in this proceeding (referred to herein as the "Evidence") consists of the Application, including updates to the Application, and PUCDI's responses to the initial and supplemental interrogatories. The Appendices to this Settlement Agreement (the "Agreement") are also included in the Evidence. The Settlement Conference was duly convened in accordance with the Procedural Order No. 4, with Mr. Paul Vlahos as facilitator.

PUCDI and the following Intervenors participated in the Settlement Conference:

- Energy Probe;
- SEC; and
- VECC.

PUCDI and the Intervenors are collectively referred to below as the "Parties". Board staff also participated in the Settlement Conference.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Board's *Settlement Conference Guidelines* (the "Guidelines"). The Parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to 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 Agreement.

The role adopted by Board Staff in the Settlement Conference is set out in page 5 of the Guidelines. Although Board staff is not a party to this Agreement, as noted in the Guidelines, Board staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

A COMPLETE SETTLEMENT HAS BEEN REACHED ON ALL ISSUES IN THIS PROCEEDING:

The Parties are pleased to advise the Board that a complete settlement has been reached on all issues in this proceeding. This document comprises the Proposed Settlement Agreement and it is presented jointly by PUCDI, Energy Probe, SEC and VECC to the Board. The Parties confirm the Evidence filed to date in respect of each settled issue, as supplemented in some instances by additional information recorded in this Agreement, supports the settlement of the matters identified in this Agreement. In addition, the Parties agree the Evidence, supplemented where necessary by the additional information appended to this Agreement, contains sufficient detail, rationale and quality of information to allow the Board to make findings in keeping with the settlement reached by the Parties.

The Parties explicitly request the Board consider and accept this Proposed Settlement Agreement as a package. With the exception of the treatment of Account 1576 discussed below, 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 Agreement. 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 which may be unacceptable to one or more of the Parties. If the Board does not accept the Agreement, other than Account 1576, in its entirety, then there is no Agreement unless the Parties agree those portions of the Agreement the Board does accept may continue as a valid settlement.

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*.

It is also agreed this Agreement 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 Agreement. However, none of the Parties will, in any subsequent proceeding, take the position the resolution therein of any issue settled in this Agreement, if contrary to the terms of this Agreement, should be applicable for all or any part of the 2013 Test Year.

References to the Evidence supporting this Agreement on each issue are set out in each section of the Agreement. The Appendices to the Agreement provide further evidentiary support. The Parties agree this Agreement and the Appendices form part of the record in EB-2012-0162. The Appendices were prepared by the Applicant. The Intervenors are relying on the accuracy and completeness of the Appendices in entering into this Agreement. Appendix I to this Agreement – Proposed Schedule of 2013 Tariff of Rates and Charges (Updated) – is the proposed schedule of Rates and Charges consistent with this Agreement, and the Parties propose that the Board issue its Final Rate Order on the basis of this Appendix.

The Parties believe the Agreement represents a balanced proposal that protects the interests of PUCDI's customers, employees and shareholder and promotes economic efficiency and cost effectiveness. It also provides the resources which will allow PUCDI to manage its assets so that the highest standards of performance are achieved and customers' expectations for the safe and reliable delivery of electricity at reasonable prices are met.

The Parties agree that the effective date of the rates resulting from this proposed Agreement is July 1, 2013 (referred to below as the "Effective Date").

The Parties agree that PUCDI will remain on a May 1 rate year. Accordingly, the effective date of PUCDI's 1st IRM following this COS Application will be May 1, 2014.

ORGANIZATION AND SUMMARY OF THE SETTLEMENT AGREEMENT:

As noted above, there is no Board-approved Issues List for this proceeding. For the purposes of organizing this Agreement, the Parties have used the Issues List in the Guelph Hydro Electric Systems Inc. proceeding (EB-2011-0123) as a guide, as that Issues List addresses all of the revenue requirement components, load forecast, deferral and variance account dispositions, cost allocation and rate design and other issues that are also relevant to determining PUCDI's 2013 distribution rates.

The following Appendices accompany this Settlement Agreement:

Appendix A – Summary of Significant Changes
Appendix B – Continuity Tables (Updated)
Appendix C – Cost of Power Calculation (Updated)
Appendix D – 2013 Customer Load Forecast (Updated)
Appendix E – 2013 Debt and Capital Structure (Updated)
Appendix F – 2013 PILS (Updated)
Appendix G – 2013 Cost of Capital (Updated)
Appendix H – 2013 Revenue Deficiency (Updated)
Appendix I – Proposed 2013 Schedule of Rates and Charges (Updated)

Appendix J – 2013 Updated Customer Impacts (Updated)
Appendix K – Cost Allocation Sheets O1 (Updated)
Appendix L – Revenue Requirement Work Form (Updated)
Appendix M – Throughput Revenue (Updated)
Appendix N – Revenue Reconciliation (Updated)
Appendix O - Draft Accounting Order
Appendix P – LRAM and LRAMVA Calculation

UNSETTLED MATTERS:

There are no unsettled matters in this proceeding.

OVERVIEW OF THE SETTLED MATTERS:

This Agreement will allow PUCDI to continue to make the necessary investments in maintenance and operation expenditures as well as capital investments to maintain the safety and reliability of the electricity distribution service that it provides.

This Agreement will also allow PUCDI to: maintain current capital investment levels and, where required, appropriately increase capital investment levels in infrastructure to ensure a reliable distribution system; manage current and future staffing levels, skills and training to ensure regulatory compliance with Codes and Regulations; promote conservation programs including the Ministry of Energy directives as a condition of PUCDI's distribution licence; and continue to provide the high level of customer service that PUCDI's customers have come to expect.

The Parties agree no rate classes face bill impacts that require mitigation efforts as a result of this Agreement.

In this Agreement, except where otherwise expressly stated, all dollar figures are calculated and expressed using Canadian Generally Accepted Accounting Principles ("CGAAP"). For the purposes of settlement, the Parties acknowledge that PUCDI is not converting to International Financial Reporting Standards ("IFRS") in the 2013 Test Year and intends to remain on CGAAP until required by the Accounting Standards Board (the "AcSB") to move to IFRS. However, PUCDI will comply with the Board's letter titled "Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies 2013" dated July 17, 2012. PUCDI has implemented the regulatory accounting changes for depreciation expense and capitalization policies effective January 1, 2012.

In PUCDI's initial evidence in Exhibit 1, Tab 2, Schedule 4, Page 2, the Service Revenue Requirement for the 2013 Test Year was $20,212,417 which included a Base Revenue Requirement of $17,944,453 and Revenue Offsets of $2,267,964 with a resulting Revenue Deficiency of $3,174,855. Through the interrogatory and settlement process, PUCDI made changes to the Service Revenue Requirement as shown in Settlement Table #1: Service Revenue Requirement as follows:

Settlement Table #1: Service Revenue Requirement

		COS Application Filing	Interrogatories	Settlement Submission	Difference Filing vs Settlement
Service Revenue Requirement	A	20,212,417	20,047,031	18,841,349	1,371,068
Revenue Offsets	B	(2,267,964)	(2,267,964)	(2,600,000)	332,036
Base Revenue Requirement	C=A+B	17,944,453	17,779,067	16,241,349	1,703,104
Revenue at Existing Rates	D	14,769,598	14,802,568	14,811,517	(41,919)
Revenue Deficiency/Sufficiency	E=C-D	3,174,855	2,976,499	1,429,832	1,745,023

The revised Service Revenue Requirement for the 2013 Test Year is $18,841,349 which reflects the updated cost of capital parameters (ROE and Deemed Short Term Debt rate) issued by the Board on February 14, 2013 applicable to applications for rebasing effective May 1, 2013. Compared to the forecast 2013 revenue at current rates of $14,811,517 the revised Service Revenue Requirement represents a revenue deficiency of $1,429,832.

Through the settlement process, PUCDI has agreed to certain adjustments from its original 2013 Application and subsequent updated Evidence. Any such changes are described in the sections below.

1.0 GENERAL

1.1 Has PUCDI responded appropriately to all relevant Board directions from previous proceedings?

Status:	**Complete Settlement**
Supporting Parties:	PUCDI, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 1, Tab 1, Schedule 15.

For the purposes of settlement the Parties accept the Evidence of the Applicant that there were no outstanding obligations or orders from previous Board decisions.

1.2 Are PUCDI's economic and business planning assumptions for 2013 appropriate?

Status:	**Complete Settlement**
Supporting Parties:	PUCDI, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 1, Tab 2, Schedule 1.

For the purposes of settlement, the Parties accept PUCDI's economic and business planning assumptions for 2013.

1.3 Is service quality, based on the Board specified performance assumptions for 2013, appropriate?

Status:	**Complete Settlement**
Supporting Parties:	PUCDI, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 2, Tab 3, Schedule 2 Board Staff IR 2-Staff-8

For the purposes of settlement, the Parties accept PUCDI's evidence with respect to the acceptability of its service quality, based on the Board-specified indicators.

1.4 What is the appropriate effective date for any new rates flowing from this Application? If that effective date is prior to the date new rates are actually implemented, what adjustments should be implemented to reflect the sufficiency or deficiency during the period from effective date to implementation date?

Status:	**Complete Settlement**
Supporting Parties:	PUCDI, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 1, Tab 1, Schedule 1.

For the purpose of settlement, the Parties accept that the appropriate effective date of the new rates flowing from this Application is July 1, 2013.

2.0 RATE BASE

2.1 Is the proposed rate base for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 1, Schedule 1
Board Staff IR 2-Staff-6
VECC IR Supplemental 1.0-VECC-42
Board Staff IR

For the purposes of settlement, the Parties agree that PUCDI's amended forecast Rate Base of $90,511,645 for the 2013 Test Year under CGAAP is appropriate. A full calculation of this agreed Rate Base is set out later in this section in Settlement Table #2: Rate Base. The 2012 revised capital expenditures and amortization expense have been updated to reflect 2012 actuals and 2013 has been adjusted accordingly. Stranded meters were removed from the 2013 opening rate base and applied to the 2012 closing rate base. The revised fixed asset continuity schedules are in Appendix B. The amortization expense for 2013 has been adjusted to reflect the agreed capital expenditure adjustments for both 2012 and 2013.

The revised Rate Base value reflects the following changes to the working capital allowance:

- The following adjustments were undertaken to revise PUCDI's Load Forecast from the initial application:
    - The 2011 actual OPA CDM results were used and their persistence assumed in equal increments for 2012, 2013, and 2014.
    - The manual CDM adjustment for 2013 has been reduced for the 2011 actual results.
    - The adjustment also reflects a full year of 2012 programs persisting into 2013 along with the half year rule being applied to 2011 and 2013 programs.
- The following adjustments were undertaken to revise PUCDI's Cost of Power Calculation from the initial application:
    - RPP and non-RPP rates were updated to reflect the change in charges effective November 1, 2012.

- The Retail Transmission Network & Connection charges were updated to reflect the change in the Ontario uniform electricity transmission rates effective January 1, 2013;
- The Wholesale Market Service charge and Rural or Remote Electricity Rate Protection (RRRP) costs were updated to reflect the revised charges effective May 1, 2013 as per EB-2013-0067.

- The Parties agree that the 2013 OM&A for the Test Year should be $9,952,946 (CGAAP), a decrease of $975,924 from $10,928,870 in the original Application. OM&A expenses are discussed in further detail under item 4.1.
- The Parties agree that the Working Capital Rate percentage will be set at 12% which is a 1% decrease from the 13% in the original application. The Allowance for Working Capital should be $9,244,875 a decrease of $436,021 from $9,680,896 in the original Application.

The changes to working capital allowance are set out in Settlement Table #3: Allowance for Working Capital, under Section 2.2 below.

Agreed upon adjustments to PUCDI's proposed Overall Rate Base under CGAAP is set out in Settlement Table #2: Rate Base, below.

Settlement Table #2: Rate Base

Rate Base

Particulars	Initial Application	Adjustments	Application after Interrogatory Responses	Adjustments	Settlement Proposal
Gross Fixed Assets (average)	$134,901,466	$ -	$134,901,466	($2,573,955)	$132,327,511
Accumulated Depreciation (average)	($52,587,960)	$ -	($52,587,960)	$1,527,219	($51,060,741)
Net Fixed Assets (average)	$82,313,506	$ -	$82,313,506	($1,046,736)	$81,266,770
Allowance for Working Capital	$9,680,896	$461,256	$10,142,152	($897,276)	$9,244,875
Total Rate Base	$91,994,402	$461,256	$92,455,658	($1,944,012)	$90,511,645

2.2 Is the working capital allowance for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit2, Tab 4, Schedule1
VECC IR Supplemental 1.0 VECC-42

For the purposes of settlement, the Parties agree to the following Working Capital Allowance calculated based on 12% of the OM&A expenses of $9,952,946 (CGAAP) and Cost of Power of $67,087,680. The reduction from 13% to 12% is intended to give effect to the reductions in required working capital that result from PUCDI's existing practice of billing all customers on a monthly basis.

As discussed in Section 2.1 and this section, the Parties agree that the adjustments shown below in Settlement Table #3: Allowance for Working Capital, reflecting the settled matters, will be made to PUCDI's Working Capital Allowance calculation:

Settlement Table #3: Allowance for Working Capital

	Initial Application	Adjustments	Application after Interrogatory Responses	Adjustments	Settlement Proposal
Controllable Expenses	$10,928,870	$ -	$10,928,870	($975,924)	$9,952,946
Cost of Power	$63,539,559	$3,548,121	$67,087,680	$ -	$67,087,680
Working Capital Base	$74,468,429	$3,548,121	$78,016,550	($975,924)	$77,040,626
Working Capital Rate %	13.00%	0.00%	13.00%	-1.00%	12.00%
Working Capital Allowance	$9,680,896	$461,256	$10,142,152	($897,276)	$9,244,875

2.3 Is the capital expenditure forecast for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 2, Schedule 4
Application: Exhibit 2, Tab 2, Schedule 7
VECC IR 2-VECC-8 (d)

For the purposes of settlement, the Parties accept net capital expenditures of $7,974,605 for the Test Year. The resulting continuity schedules are shown in Appendix B.

2.4 Is the capitalization policy and allocation procedure appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 2, Schedule 1

For the purposes of settlement, the Parties accept PUCDI's capitalization policy as it was set out in Exhibit 2, Tab 2, Schedule 1, of the original Application. The Parties agree that PUCDI should use deferral account 1576 to record 2012 adjustments to PP&E as a result of PUCDI adopting updated asset lives and overhead capitalization policies effective January 1, 2012. This is detailed under Section 4.2.

3.0 LOAD FORECAST AND OPERATING REVENUE

3.1 Is the load forecast methodology including weather normalization appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence:
Application: Exhibit 3, Tab 2, Schedule 1
Board Staff Interrogatory 3-Staff-23
Board Staff Interrogatory 3-Staff-24
VECC Interrogatory 3-VECC-19
VECC Supplemental Interrogatory 3-VECC-46
VECC Supplemental Interrogatory 3-VECC-47
Board Staff Supplemental Interrogatory 3-Staff-64

For the purposes of settlement, the Parties accept PUCDI's load forecast methodology, including weather normalization, as modified through the settlement process as follows:

- Changes to the load forecast for the purposes of settlement, included in the CDM manual adjustment, were the 2011 Final OPA program results (detailed in Section 3.3 below). The adjustment also reflects a full year of 2012 programs persisting into 2013 along with the half year rule being applied to 2011 and 2013 programs.

This results in a billed consumption forecast of 703,408,250 kWh and 651,673 kW in the 2013 Test Year. The accepted CDM adjustment for 2012 and 2013 CDM programs is 6,363,254 kWh for the 2013 Test Year. This does not include the adjustment for the 2011 programs as the 2011 programs are already reflected in the load forecast.

3.2 Are the proposed customers/connections and load forecasts (both kWh and kW) for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence:
Application: Exhibit 3, Tab 2, Schedule 1
Board Staff Interrogatory 3-Staff-23
Board Staff Interrogatory 3-Staff-24
VECC Interrogatory 3-VECC-19
VECC Supplemental Interrogatory 3-VECC-46

VECC Supplemental Interrogatory 3-VECC-47
Board Staff Supplemental Interrogatory 3-Staff-64

For the purposes of settlement, the Parties accept PUCDI's customers/connections forecast (both kWh and kW) for the 2013 Test Year. With respect to the load forecast, through the settlement process PUCDI modified the movement of the CDM manual adjustment to reflect the half year rule for 2011 and 2013 program results. Settlement Table #4: Load Forecast, details the above changes. Appendix D reflects the revised load forecast.

Settlement Table #4: Load Forecast

Rate Class	Initial Application/Filing	Settlement Adjustments	Settlement Agreement
Residential			
Customers	29,271	-	29,271
kWh	339,164,253	1,397,196	340,561,449
GS<50			
Customers	3,401	-	3,401
kWh	101,760,560	419,206	102,179,766
GS>50			
Customers	399	-	399
kWh	250,600,517	1,032,303	251,632,820
kW	625,708	2,578	628,286
USL			
Customers	21	-	21
kWh	869,310	3,579	872,889
Sentinel Lights			
Customers	387	-	387
kWh	253,123	1,042	254,165
kW	707	3	710
Street Lights			
Customers	8,904	-	8,904
kWh	7,874,740	32,420	7,907,160
kW	22,587	93	22,680
Totals			
Customers/Connections	42,383	-	42,383
kWh	700,522,503	2,885,746	703,408,249
kW	649,002	2,674	651,676

3.3 Is the impact of CDM appropriately reflected in the load forecast?

Status:	**Complete Settlement**
Supporting Parties:	PUCDI, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 3, Tab 2, Schedule 1 Board Staff Interrogatory 3-Staff-23 Board Staff Interrogatory 3-Staff-24 VECC Interrogatory 3-VECC-19 VECC Supplemental Interrogatory 3-VECC-46 VECC Supplemental Interrogatory 3-VECC-47 Board Staff Supplemental Interrogatory 3-Staff-64

For the purposes of settlement, the Parties agree that the CDM adjustment should be changed to reflect the half year rule for 2011 and 2013 program results. The application of the half year rule for 2011 is appropriate because the historical 2011 data used in the regression analysis would have included one half of the annual CDM savings for 2011 programs. The CDM adjustment for 2011, 2012 and 2013 CDM programs to the 2013 Test Year load forecast has been allocated to each rate class based on the proportion of the class kWh to the total. Settlement Table #5: CDM Adjusted Forecast, below provides the CDM impact on billed kW and kWh per customer class.

Settlement Table #5: CDM Adjusted Forecast

Rate Class	Billed Load Forecast Prior to CDM Adjustment kWh	Billed Load Forecast After CDM Adjustment kWh	CDM Adjustment kWh
Residential	343,642,357	340,561,450	3,080,907
GS<50	103,104,140	102,179,766	924,374
GS>50	253,909,116	251,632,820	2,276,296
USL	880,780	872,889	7,891
Sentinel Lights	256,463	254,165	2,298
Street Lights	7,978,647	7,907,160	71,487
Totals	709,771,503	703,408,250	6,363,253

Rate Class	Billed Load Forecast Prior to CDM Adjustment kW	Billed Load Forecast After CDM Adjustment kW	CDM Adjustment kW
GS>50	633,969	628,283	5,686
Sentinel Lights	717	710	7
Street Lights	22,885	22,680	205
Totals	657,571	651,673	5,898

Table #6 below is PUCDI's proposed schedule to achieve the 4 year kWh CDM target. This is used to determine the LRAMVA kWh's for the 2013 test year.

Settlement Table #6: LRAMVA

LRAMVA Calculation					
30,830,000					
	2011	2012	2013	2014	Total
2011 Programs	8.9%	8.9%	8.9%	8.5%	35.2%
2012 Programs		10.8%	10.8%	10.8%	32.4%
2013 Programs			10.8%	10.8%	21.6%
2014 Programs				10.8%	10.8%
	8.9%	19.7%	30.5%	40.9%	100.0%
kWh					
	2011	2012	2013	2014	Total
2011 Programs	2,744,164	2,744,164	2,744,163	2,632,822	10,865,313
2012 Programs		3,327,448	3,327,448	3,327,448	9,982,344
2013 Programs			3,327,448	3,327,448	6,654,896
2014 Programs				3,327,447	3,327,447
	2,744,164	6,071,612	9,399,059	12,615,165	30,830,000

Table #7 below is PUCDI's 2013 proposed CDM savings from 2012 and 2013 programs for the LRAMVA account by rate class.

Settlement Table #7: LRAMVA by Rate Class

2013 CDM Savings from 2012 and 2013 programs for LRAM varaince account by rate class							
	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
kWh	4,550,758	1,365,379	3,362,279	3,394	105,593	11,657	9,399,059
kW where applicable			8,396	10	295		8,700

3.4 Is the proposed forecast of test year throughput revenue appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 3, Tab 2, Schedule 1

For the purposes of settlement, the Parties agree on the throughput revenue as set out in Appendix M: Throughput Revenue.

3.5 Is the test year forecast of other revenues appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 3, Tab 3, Schedule 1
VECC Interrogatory 3-VECC-22
Energy Probe Interrogatory 3-EP-13
Energy Probe Supplemental Interrogatory 3-EP-32s
Energy Probe Supplemental Interrogatory 3-EP-33s
VECC Supplemental Interrogatory 3.0-VECC-48
VECC Supplemental Interrogatory 3.0-VECC-49

For the purposes of settlement, the Parties agree upon Other Distribution Revenue as $2,600,000 versus the $2,267,964 set out in the original application. Other Distribution Revenue is as follows:

	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Test Year
Other Distribution Revenue	972,722	1,487,040	1,123,326	1,056,621	1,542,460	1,417,993	1,282,726
Rent (Due to new admin/service center owned by PUC Distribution)							1,317,274
Total	972,722	1,487,040	1,123,326	1,056,621	1,542,460	1,417,993	2,600,000

4.0 OPERATING COSTS

4.1 Is the overall OM&A forecast for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence:
Application: Exhibit 4, Tab 1, Schedule 1
Application: Exhibit 4, Tab 2, Schedule 1
Board Staff Interrogatory IR 2-Staff-7
VECC Interrogatory 4-VECC-23
VECC Interrogatory 4-VECC-26
Energy Probe Interrogatory 4-EP-17
SEC Interrogatory 4-SEC-21

For the purposes of settlement, the Parties agree the 2013 OM&A for the Test Year should be $9,952,946 (CGAAP), a decrease of $975,924 from the $10,928,870 set out in the original Application. The Parties relied on PUCDI's representation that it can safely and reliably operate the distribution system based on the total OM&A budget proposed. PUCDI has provided on a preliminary basis, in Settlement Table #8: OM&A Expense Budget below, a revised OM&A budget based on pro-ration of the proposed total amount. The breakdown of the budget into categories is not intended by the Parties to be in any way a deviation from the normal rule that, once the budget is established, it is up to management to determine through the year how best to spend that budget given the actual circumstances and priorities of the company throughout the Test Year.

PUCDI has a corporate commitment to seeking new ways of improving its productivity and efficiency. The Intervenors support PUCDI's productivity goals and notwithstanding the foregoing comments regarding management's discretion as to how the OM&A budget will be spent, the Parties have agreed to ring-fence an average amount of $100,000 per year, totalling $400,000, of PUCDI's OM&A monies and/or revenue requirement on capital expenditures, to be spent in the period from the effective date of the rates arising out of this Application through April 30, 2017 on furthering PUCDI's productivity and efficiency. The OM&A expenditures are included in, and not in addition to, the Board-approved OM&A amount, which for the 2013 Test Year the Parties have agreed should be $9,952,946.

The amount to be spent each year, and the projects on which it is spent, will be at the discretion of PUCDI. Expenditures in this regard may include, without limitation, studies and/or projects involving external consultants, although studies and/or projects using PUCDI's internal resources will also be permitted. The studies and/or projects may relate, again without limitation, to matters such as:

- Cost reductions in billing, possibly through the increased use of online billing and bill payment;
- Reductions in other administrative costs;
- Reducing OM&A per customer;
- Time-of-use data usage for outage management;
- Time-of-use data for maintenance planning;
- Implementation of electronic Daily Service Order system;
- Meter-to-Cash Business Process Review;

New studies and/or projects may be allocated to this $400,000 total expenditure, and previously planned studies and/or projects may be implemented using this proposed $400,000 total expenditure. Expenditures in this regard will be tracked in a new variance account to be called the "Productivity Initiatives Variance Account", discussed under Issue 9.1, below. The Parties propose that this account be a subaccount of 1508 – "Other Regulatory Assets". PUCDI will report on the projects and other initiatives funded through this account at the time of its next rebasing rate application, including the amounts spent, the nature and purpose of each project, and the intended and actual results. Any amounts of the total $400,000 not spent on productivity- and efficiency-related studies and/or projects will be returned to customers by way of an appropriate credit rate rider to be determined at the time of PUCDI's next rebasing rate application.

The mechanics of this fund will be as follows; On the first of each month, commencing July 1, 2013 and continuing to and including March 1, 2017, PUCDI will credit $8,700 to a new variance account, to be called the Productivity Initiatives Variance Account, and be a sub-account within account 1508. There will be a further credit of $8,500 on April 1, 2017. As PUCDI spends money on qualifying projects and initiatives, those expenditures will be debited to the account up to a maximum of $400,000. On April 30, 2017, any net debit balance in the account will be cleared to the shareholder, but credit balance remaining in the account will be disposed of by way of a credit to ratepayers. A Draft Accounting Order is included in Appendix O.

Settlement Table #8: OM&A Expense Budget

	Initial Application	Interrogatories	Settlement Agreement
Operations	3,624,764	3,624,764	3,301,081
Maintenance	2,446,546	2,446,546	2,228,075
Billing and Collecting	1,316,331	1,316,331	1,198,786
Community Relations	636,637	636,637	579,787
Administrative and Ger	2,904,592	2,904,592	2,645,218
Total	10,928,870	10,928,870	9,952,946

4.2 Is the proposed level of depreciation/amortization expense for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 4, Tab 2, Schedule 6

For the purposes of settlement, the Parties accept the useful lives proposed by PUCDI in Settlement Table #9: Depreciation Useful Lives, below, and the depreciation expense reported in the continuity schedules in Appendix B.

As cited in PUCDI's Application, the Applicant adopted revised depreciation periods which were detailed in Exhibit 2, Tab 2, and Schedule 3. The analysis in Exhibit 2, Tab 2, Schedule 3, provides comparisons to depreciation rates adopted by PUCDI with the typical useful lives as indicated in the Kinectrics Study dated July 8, 2010 which was commissioned by the OEB. PUCDI is implementing this depreciation approach effective from January 1, 2012 and has applied it to both the Bridge Year and Test Year in its evidence. As a result of implementing the changes to extended lives and overhead capitalization policies in 2012, PUCDI is required to record the effect of the changes to PP&E in 2012 in account 1576.

It was agreed by all Parties that PUCDI is operating under CGAAP accounting principles in both the Bridge and Test Year as opposed to Modified IFRS. As a result, it was appropriate to change the deferral account to capture 2012 PP&E adjustments (extended lives and overhead capitalization only) from account 1575 to 1576. As part of the settlement agreement, it was agreed by all Parties that in PUCDI's circumstances the entries to, and clearance of, Account 1576 for PP&E accounting changes in 2012 should mirror the similar entries and clearance in 1575 on conversion to IFRS. This has resulted in the reintroduction of the WACC adjustment, now $291,502 as detailed in Appendix B below. The impacts of account 1576 (reduction in depreciation expense, overhead capitalization and WACC adjustment) will remain in place for four years and will be removed from rates during PUCDI's next Cost of Service Application in 2017. PUCDI will credit $291,502 in account 1576 with and offsetting entry to account 4305 Regulatory Debit.

The inclusion of the WACC adjustment as it relates to account 1576 has been agreed to by all Parties. Should the Board determine that it is not willing to approve this Agreement including the Parties' proposed treatment of Account 1576, this issue is severable from the rest of the Agreement. All Parties agree that, in those circumstances, this issue should be resolved by the Board after written submissions, and an oral hearing is not required.

Settlement Table #9: Depreciation Useful Lives

Description	OEB Account #	Existing estimated useful life	Proposed Estimated useful life	Kinectrics Numbers
Poles	1830	25	45	Min. 35 Typical 45 Max 75
Conductors	1835	25	60	Min. 50 Typical 60 Max 75
Overhead transformers and voltage regulators	1850	25	40	Min. 30 Typical 40 Max 60
Switches and reclosers	1835	25	60	Min. 30 Typical 45 Max 55
Distribution Station transformers and switchgear	1820/1815	30/40	40	Min. 30 Typical 40 Max 60
Batteries	1825	30	15	Min. 10 Typical 15 Max 15
Station buildings	1808	50	50	Min. 50 Max 75
Services	1855	25	40	
Underground primary cable	1845	25	40	Min. 35 Typical 40 Max 55
Underground secondary cable	1845	25	40	Min. 35 Typical 40 Max 60
Ducts	1840	25	50	Min. 30 Typical 50 Max 85
Transformers (pad mount and submersible)	1850	25	40	Min. 20 Typical 40 Max 60
Switch gear and junction cubicle	1845	25	40	Min. 20 Typical 30 Max 45
Industrial and commercial meters	1860	25	25	Min. 25 Typical 25 Max 35
Smart meters	1860	15	15	Min. 15 Typical 15 Max 20
Smart meters - repeaters	1860	15	15	Min. 5 Typical 10 Max 15
Smart meters- data concentrators	1860	15	15	Min. 10 Typical 20 Max 20
Computer hardware	1920	5	5	Min. 3 Max 5
Computer software	1925	5	5	Min. 2 Max 5
System supervisory equipment	1980	15	20	Min. 15 Typical 20 Max 30
Contributions and grants	1995	25	40	

4.3 Are the 2013 compensation costs and employee levels appropriate?

Status:	**Complete Settlement**
Supporting Parties:	PUCDI, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 4, Tab 2, Schedule 3 SEC Interrogatory 4-SEC-21 Board Staff Interrogatory 4-Staff-29 SEC Interrogatory 4-SEC-26 VECC Interrogatory 4-VECC-32 VECC Interrogatory 4-VECC-33 Board Staff Interrogatory 4-Staff-30 Board Staff Interrogatory 4-Staff-31 Energy Probe Interrogatory 4-EP-18 Energy Probe Supplemental Interrogatory 4-EP-36s VECC Supplemental Interrogatory 4.0-VECC-50 SEC Supplemental Interrogatory 4-SEC-47s SEC Supplemental Interrogatory 4-SEC-48s VECC Supplemental Interrogatory 4.0-VECC-51

For the purpose of settlement, the Parties accept PUCDI's forecasted 2013 Test Year compensation costs and employee levels.

4.4 Is the test year forecast of property taxes appropriate?

Status:	**Complete Settlement**
Supporting Parties:	PUCDI, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 4, Tab 2, Schedule 2 Energy Probe Interrogatory 2-EP-8 Energy Probe Interrogatory 2-EP-17 Energy Probe Supplemental Interrogatory 4-EP-35s VECC Supplemental Interrogatory 4-EP-37s

PUCDI has included $804,002 in property taxes payable. Also, PUCDI included $50,000 in Lieu of Property Tax, paid to the Ontario Electricity Financial Corporation, as prescribed by subsection 92 (1) of the *Electricity Act, 1998* and Ontario Regulation 423/11 in the 2013 Test Year OM&A. For the purpose of settlement, the Parties accept that the amount is appropriate.

4.5 Is the test year forecast of PILs appropriate?

Status:	**Complete Settlement**
Supporting Parties:	PUCDI, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 4, Tab 3, Schedule 1 Energy Probe Interrogatory 4-EP-19

For the purpose of settlement, the Parties accept PUCDI's 2013 Test Year PILs forecast of $249,265 as set out in Appendix F to this Settlement Agreement. Please see Appendix F – 2013 PILs (Updated), for additional details.

5.0 CAPITAL STRUCTURE AND COST OF CAPITAL

5.1 Is the proposed capital structure, rate of return on equity and short term debt rate appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

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

For the purposes of settlement, the Parties agree that PUCDI's proposed capital structure of 56% long term debt, 4% short term debt, and 40% equity is appropriate.

The short term debt rate the ROE was changed in the interrogatory phase to 2.07%, and 8.98% to reflect the Board's deemed short term debt rate and ROE applicable to cost of service applications for rates effective May 1, 2013.

Settlement Table #10: Deemed Capital Structure for 2013

Deemed Capital Structure for 2013

Description	$	% of Rate Base (Capitalization Ratio)	Rate of Return (Cost Rate)	Return
Long Term Debt	50,686,521	56.00%	3.91%	1,981,843
Unfunded Short Term Debt	3,620,466	4.00%	2.07%	74,944
Total Debt	54,306,987	60.00%		2,056,787
Common Share Equity	36,204,658	40.00%	8.98%	3,251,178
Total equity	36,204,658	40.00%		3,251,178
Total Rate Base	90,511,645	100.00%	5.86%	5,307,965

5.2 Is the proposed long term debt rate appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 5, Tab 1, Schedule 3
Board Staff Interrogatory 5-Staff-44
SEC Interrogatory 5-SEC-29

Energy Probe Interrogatory 5-EP-21
Energy Probe Supplemental Interrogatory 5-EP-38s

For the purposes of settlement, the Parties accept PUCDI's long term debt rate of 3.91%. The calculation of the long term debt rate is set out in Appendix E to this Agreement.

The Parties agree on the following changes with respect to debt rates.

- The interest rate on the Infrastructure Ontario Loans is now 3.29% and 3.79%, based on 15 year and 25 year terms respectively, changed from 4.12%. As a result, PUCDI's weighted average long term debt rate is 3.91%.

6.0 STRANDED METERS

6.1 Is the proposal related to Stranded Meters appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 9, Tab 2, Schedule 1
Energy Probe Interrogatory 2-EP-6
Board Staff Interrogatory 9-Staff-60
VECC Interrogatory 9-VECC-40
Energy Probe Interrogatory 9-EP-26
SEC Interrogatory 9-SEC-31
SEC Supplemental Interrogatory 9-Staff-60

The Parties have agreed for the purposes of settlement, that PUCDI has appropriately calculated the Stranded Meter Net Book Value as $1,349,557. The Parties further agreed on the allocation methodology utilized to calculate the Stranded Meter Rate Rider. PUCDI utilized an actual stranded meter asset listing to determine the allocation to the Residential and GS< 50 kWh rate classes. The proposed SME Rate Riders are reflected in the following Table 11. PUCDI also included in the proposed Tariff of Rates and Charges the SME charge of $0.79 per month per customer for the residential and general service rate class as per Board Decision EB-2012-011.

Settlement Table #11: Stranded Meter Customer Class Rate Rider

	Customer Class Rate Rider		
Allocation of Stranded Meter Costs	**Total Capital**	**Less: Interval Meters ($)**	**Stranded Meters ($)**
Capital Cost	4,478,779	41,668	4,437,111
Accumulated Amortization	3,103,768	16,214	3,087,554
Net Book Value	1,375,011	25,454	1,349,557

	Residential	**GS<50**	**GS>50**	**Total**
Number of Customers - 2013 Forecast	29,271	3,401	399	33,071
Allocation of Meter Costs - based on estimated NBV	73.47%	24.60%	1.93%	100.00%
Stranded Assets	991,509	332,048	26,000	1,349,557
Stranded Meter Rate Rider per Customer per Month	**3.39**	**9.76**	**6.52**	
based on 10 months from effective date July 1, 2013 to April 30, 2014				

7.0 COST ALLOCATION

7.1 Is PUCDI's cost allocation appropriate

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 7
Board Staff Interrogatory 7-Staff-45
VECC Interrogatory 7-VECC-37
Energy Probe Interrogatory 7-EP-23
VECC Supplemental Interrogatory 7.0-VECC-54
Energy Probe Supplemental Interrogatory 7- EP-39s
Energy Probe Supplemental Interrogatory 7- EP-40s
Board Staff Supplemental Interrogatory 7-Staff-70s

For the purposes of settlement, the Parties agree that revenue-to-cost ratios for the 2013 Test Year, reflecting the agreed-upon 2013 Test Year Revenue Requirement, will be as set out in Settlement Table #12: 2013 Test Year Revenue to Cost Ratios, below.

Settlement Table #12: 2013 Test Year Revenue to Cost Ratios

Cost Allocation Based Calculations

Class	Revenue Requirement - 2013 Cost Allocation Model	2013 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2013 Cost Allocation Model	Total Revenue	Revenue Cost Ratio	Proposed Revenue to Cost Ratio	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue	Board Target Low	Board Target High
Residential	11,580,870	9,069,512	1,663,492	10,733,004	92.7%	92.7%	10,733,004	1,663,492	9,069,512	85%	115%
GS < 50 kW	2,673,048	2,664,966	367,302	3,032,268	113.4%	113.4%	3,032,268	367,302	2,664,966	80%	120%
GS >50 kW	3,475,269	3,725,714	428,425	4,154,139	119.5%	119.5%	4,154,139	428,425	3,725,714	80%	120%
Sentinel Lights	45,301	31,753	5,859	37,612	83.0%	83.0%	37,612	5,859	31,753	80%	120%
Street Lighting	1,033,492	720,198	130,715	850,913	82.3%	82.3%	850,913	130,715	720,198	70%	120%
USL	33,369	29,206	4,207	33,413	100.1%	100.1%	33,413	4,207	29,206	80%	120%
TOTAL	18,841,349	16,241,349	2,600,000	18,841,349	100.0%		18,841,349	2,600,000	16,241,349		

The revenue to cost ratios above include the following adjustments,

- Adjustment of demand allocators based on revisions to load forecast.
- Adjustments to the Revenue Requirement as a result of this settlement (i.e. OM&A, Capital Expenditures, Other Revenue Offsets, etc.)

As a result of the settlement changes above, the revenue-to-cost ratios are now in the boundaries of Board-approved ranges.

The Cost Allocation Sheet O1 has been enclosed in Appendix K.

7.2 Are the proposed revenue-to-cost ratios for each class appropriate?

Status:	**Complete Settlement**
Supporting Parties:	PUCDI, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 7

For the purposes of settlement, the Parties accept the revenue-to-cost ratios for the 2013 Test Year, as set out under issue 7.1, above, and that no further adjustments will be required from 2014-2016 as part of this Agreement. The Parties acknowledge that PUCDI's revenue-to-cost ratios remain subject to further Board policy changes of general application over this period.

8.0 RATE DESIGN

8.1 Are the fixed-variable splits for each class appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 8, Tab 1, Schedule 3
SEC Interrogatory 8-SEC-30

For the purposes of settlement, the Parties accept the current fixed-variable splits for each class presented in Settlement Table #13: Fixed Charge Analysis, below, subject to agreed-upon change to the GS>50 kW Monthly Service Charge discussed below.

Settlement Table #13: Fixed Charge Analysis

Fixed Charge Analysis								
Customer Class	Current Volumetric Split	Current Fixed Charge Spilt	Total	Fixed Rate Based on Current Fixed/Variable Revenue Proportions	2012 Rates From OEB Approved Tariff	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model)	Target Fixed Charge Split	Proposed Fixed Charge
Residential	62.59%	37.41%	100.00%	9.66	8.81	15.12	37.41%	9.66
GS < 50 kW	74.81%	25.19%	100.00%	16.45	15.00	23.95	25.19%	16.45
GS >50 kW	79.32%	20.68%	100.00%	160.91	146.74	30.51	20.68%	160.91
Sentinel Lights	58.78%	41.22%	100.00%	2.82	2.57	10.56	41.22%	2.82
Street Lighting	58.03%	41.97%	100.00%	2.83	2.58	10.38	41.97%	2.83
USL	89.47%	10.53%	100.00%	12.20	11.13	10.57	10.53%	12.20

The Parties agree that the Proposed Monthly Service Charge for the GS>50 to 4,999 rate class will be $110.00. This results in a fixed-variable split of 13.82% and 86.18%.The fixed and variable rates are set out in Settlement Table #14: 2013 Base Revenue Distribution Rates, below.

Settlement Table #14: 2013 Base Revenue Distribution Rates

Distribution Rate Allocation Between Fixed & Variable Rates For 2013 Test Year

Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Resulting Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue	Total
Residential	9,069,512	55.84%	9.66	$0.0167	$ 3,393,261	$ 5,676,251		9,069,512	9,069,512
GS < 50 kW	2,664,966	16.41%	16.45	$0.019718	$ 671,277	$ 1,993,689	$ 21,064	2,686,030	2,686,030
GS >50 kW	3,725,714	22.94%	110.00	$5.2254	$ 526,680	$ 3,199,034	$ 84,036	3,809,750	3,809,750
Sentinel Lights	31,753	0.20%	2.82	$26.2894	$ 13,087	$ 18,665		31,753	31,753
Street Lighting	720,198	4.43%	2.83	$18.4267	$ 302,279	$ 417,918		720,198	720,198
USL	29,206	0.18%	12.20	$0.0299	$ 3,076	$ 26,130		29,206	29,206
TOTAL	**16,241,349**	**100%**			**$ 4,909,660**	**$ 11,331,689**	**$ 105,100**	**$ 16,346,449**	**$ 16,346,449**
			Forecast Fixed/Variable Rati		**30.035%**	**69.322%**	**0.643%**	**100.000%**	

8.2 Are the proposed retail transmission service rates ("RTSR") appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 8, Tab 1, Schedule
Board Staff Interrogatory 8-Staff-50
VECC Interrogatory 8-VECC-38

For the purposes of settlement the Parties agree that the Retail Transmission Service Rates ("RTSRs"), should be updated for the Uniform Transmission Rates issued by the Board on December 20, 2012 in EB-2012-0031, are appropriate, and are as set out in Settlement Table #15: RTSR Network Rates, below.

Settlement Table #15: RTSR Network and RTSR Connection Rates

Rate Class			As filed in the application	Proposed RTSR Network rates updated with January 1, 2013 approved rates
Residential		kWh	0.0058	0.0059
General Service Less Than 50 kW		kWh	0.0054	0.0055
General Service 50 to 4,999 kW		kW	2.2063	2.2434
General Service 50 to 4,999 kW – Interval Metered		kW	2.7747	2.8214
Unmetered Scattered Load		kWh	0.0054	0.0055
Sentinel Lighting		kW	1.6724	1.7006
Street Lighting		kW	1.6639	1.6919

8.3 Are the proposed loss factors appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 8, Tab 1, Schedule 5
Board Staff Interrogatory 8-Staff-51

For the purposes of settlement, the Parties accept the Total Loss Factors for Primary Metered Customers < 5,000 kW (1.0385) and Secondary Metered Customers < 5,000 kW (1.0489) as set out in IR #8-Staff 51. The loss factors accepted by the Parties are as set out in Settlement Table #16: Loss Factors, below.

Settlement Table #16: Loss Factors

Appendix 2-P
Loss Factors

		Historical Years					5-Year Average
		2007	2008	2009	2010	2011	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	738,093,576	740,966,486	732,869,984	714,199,062	745,049,194	734,235,660
A(2)	"Wholesale" kWh delivered to distributor (lower value)	738,093,576	740,966,486	732,869,984	714,199,062	745,049,194	734,235,660
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	738,093,576	740,966,486	732,869,984	714,199,062	745,049,194	734,235,660
D	"Retail" kWh delivered by distributor	701,800,772	710,698,626	707,756,700	683,757,862	711,929,017	703,188,595
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						0
F	Net "Retail" kWh delivered by distributor = **D - E**	701,800,772	710,698,626	707,756,700	683,757,862	711,929,017	703,188,595
G	Loss Factor in Distributor's system = **C / F**	1.0517	1.0426	1.0355	1.0445	1.0465	1.0442
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0564	1.0473	1.0401	1.0492	1.0512	1.0489

9.0 DEFERRAL AND VARIANCE ACCOUNTS

9.1 Are the account balances, cost allocation methodology and disposition period appropriate?

Status: **Complete Settlement**

Supporting Parties: PUCDI, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 9
Board Staff 9-Staff-56
Board Staff 9-Staff-57

For the purposes of settlement, the Parties agree that the account balances, cost allocation methodology and disposition period for the deferral and variance accounts as presented in the evidence cited above, adjusted for the matters discussed below, are appropriate.

- The Parties have agreed for the purposes of settlement, that PUCDI has appropriately calculated the Stranded Meter Net Book Value as $1,349,557, to be recorded in a sub-account of account 1555 (Stranded Meters). The Parties further agreed on the allocation methodology utilized to calculate the Stranded Meter Rate Rider, as described in section 6.1 of this agreement.

- The Parties agree for the purposes of settlement, the balances of the deferral and variance accounts for disposal will include the interest accrued until June 30, 2013. The balances will be disposed of over a 10 month period from July 1, 2013 to April 30, 2014.

- The Parties agree that PUCDI should use account 1576-Accounting changes under CGAAP (1575 original application) to record the impact of PUCDI adopting accounting policy changes for useful lives and overhead capitalization effective January 1, 2012. The balance agreed upon for disposition is $291,502 (credit balance). The balance of $291,502 will be returned to customers over a 4 year period commencing July 1, 2013 as a reduction to depreciation expense, in accordance with the APH FAQ July 2012 #2 as the guidance for the treatment of Account 1576. The yearly reduction to depreciation expense of $72,876 is detailed in Appendix B below. The Parties agreed to include a WACC adjustment of $17,082 (5.86%) in the determination of rates. This deferral account is not subject to interest.

- With respect to the Sub-Account Global Adjustment, the Parties agree that PUCDI should revise the kW allocator for the Non-RPP GS>50 to 544,238 kW instead of the 675,864 kW shown in the original application, in accordance with PUCDI's response to IR #9-Staff-51. As a result of the settlement PUCDI reduced the kW to 451,980 to adjust for the 10 month disposition period based on the 10 month actual forecast.

- With respect to LRAM, the parties agree the disposition period should be revised to include persisting lost revenue from January 1, 2012 to April 30, 2012 from 2005-2010 CDM programs. The LRAM Rate Rider calculations are included as Appendix P.

- The Parties agree the recalculated DVA riders, based on the updated amount of a credit of $2,638,187, should be calculated to June 30, 2013.

- The Parties agree to the disposition of all other Group 1 and Group 2 accounts "on a final basis" as set forth in Settlement Table #17 over a 10 month period commencing July 1, 2013.

- As discussed under Issue 4.1, above, PUCDI has a corporate commitment to seeking new ways of improving its productivity and efficiency.. The intervenors support PUCDI's productivity goals. The Parties have agreed to ring-fence an average amount of $100,000 per year, totalling $400,000, of PUCDI's OM&A monies and/or revenue requirement on capital expenditures to be spent in the period from the effective date of the rates arising out the Application through April 30, 2017 on furthering PUCDI's productivity and efficiency. The amount to be spent each year, and the projects on which it is spent, will be at the discretion of PUCDI. Expenditures in this regard will be tracked in a new variance account to be called the "Productivity Initiatives Deferral Account". The Parties propose that this account be a subaccount of 1508 – "Other Regulatory Assets". PUCDI will report on the expenditures at the time of its next rebasing rate application. Any amounts of the total $400,000 not spent on productivity- and efficiency-related studies and/or projects will be returned to customers by way of an appropriate credit rate rider to be determined at the time of PUCDI's next rebasing.

- Settlement Table #18: Group 1 & Group 2 Deferral and Variance Accounts, below summarizes the Parties' agreement with respect to the disposal of the balances of the accounts:

Settlement Table #17: Group 1 & Group 2 Deferral and Variance Accounts

Group 1 Accounts	Account Number	Principal Balance	Interest balance	Total Claim
RSVA - Wholesale Market Service Charge	1580	(996,241)	(34,877)	(1,031,118)
RSVA - Retail Transmission Network Charge	1584	(182,906)	(3,001)	(185,907)
RSVA - Power (excluding Global Adjustment)	1588	(1,421,736)	(75,796)	(1,497,532)
RSVA - Power - Sub-account - Global Adjustm	1588	392,539	29,468	422,007
Disposition and Recovery/Refund of Regulatory	1595	(74,909)	(15,849)	(90,758)
Group 1 Subtotal		(2,283,253)	(100,055)	(2,383,308)
Group 2 Accounts				
Retail Cost Variance Account - Retail	1518	(388,122)	(51,337)	(439,459)
Retail Cost Variance Account - STR	1548	161,142	17,265	178,407
Deferred Rate Impact Amounts - PILS recovery (EB-2007-0723)	1574	243,685	24,019	267,704
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	(9,241)	(1,375)	(10,616)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(249,311)	(1,604)	(250,915)
Group 2 Sub Total		(241,847)	(13,032)	(254,879)
Group 1 & Group 2 Total		(2,525,100)	(113,087)	(2,638,187)

Settlement Table #18: Group 1 & Group 2 DVA Disposition Amounts Excluding Global Adjustment

	Account Number	Principal Balance	Interest balance	Total Claim
RSVA - Wholesale Market Service Charge	1580	(996,241)	(34,877)	(1,031,118)
RSVA - Retail Transmission Network Charge	1584	(182,906)	(3,001)	(185,907)
RSVA - Power (excluding Global Adjustment)	1588	(1,421,736)	(75,796)	(1,497,532)
Disposition and Recovery/Refund of Regulatory	1595	(74,909)	(15,849)	(90,758)
Retail Cost Variance Account - Retail	1518	(388,122)	(51,337)	(439,459)
Retail Cost Variance Account - STR	1548	161,142	17,265	178,407
Deferred Rate Impact Amounts	1574	243,685	24,019	267,704
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	(9,241)	(1,375)	(10,616)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(249,311)	(1,604)	(250,915)
Total		(2,917,639)	(142,555)	(3,060,194)

9.2 Are the proposed rate riders to dispose of the account balances appropriate?

Status:	**Complete Settlement**
Supporting Parties:	PUCDI, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 9 Board Staff Interrogatory 4-Staff-40 Board Staff Interrogatory 9-Staff-54 Board Staff Interrogatory 9-Staff-60

For the purposes of settlement, the Parties accept the proposed rate riders to dispose of those account balances that are the subject of disposition at this time on a final basis. The Parties agree to a disposition period of 10 months in light of the agreed-upon effective date of July 1, 2013. As noted in section 6.1 above, the Parties agree, for the purposes of settlement that the Stranded Meter recovery period will be over 10 months, commencing July 1, 2013.

All Parties agree that the disposition period of 10 months will be the period of July 1, 2013 to April 30, 2014. In the event the necessary riders cannot be implemented on July 1, 2013, PUCDI will adjust the quantum of the riders to maintain the same sunset date (April 30, 2014) or make whatever alternative adjustment the Board may require. Settlement Table #19: Deferral and Variance Account Disposition Balances below reflects the balances of the accounts being disposed.

Settlement Table #19: Deferral and Variance Account Disposition Rate Riders

Settlement Table #19: Deferral and Variance Account Disposition Rate Riders below reflects the rate riders for disposition over a period of 10 months. PUCDI estimated the kW/kWh's based on a 10 month period by removing the projected purchases from May and June 2013 from the regression model. The kWh and kWs were allocated to the rate class consistent with the method used in the regression analysis. Refer to the revised billing determinants tab in the EDDVAR continuity schedule submitted with the proposed settlement agreement.

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1588 sub-account)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	289,979,604	-$ 1,528,827	- 0.0053	$/kWh
General Service < 50	kWh	87,003,529	-$ 425,426	- 0.0049	$/kWh
General Service > 50	kW	542,377	-$ 1,014,185	- 1.8699	$/kW
USL	kWh	727,407	-$ 3,546	- 0.0049	$/kWh
Sentinel Lights	kW	591	-$ 2,725	- 4.6117	$/kW
Street Lights	kW	18,900	-$ 85,485	- 4.5230	$/kW
		-	$ -	-	
		-	$ -	-	
Total			**-$ 3,060,195**		

Rate Rider Calculation for RSVA - Power - Sub-account - Global Adjustment

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of RSVA - Power - Sub-	Rate Rider for RSVA - Power -	
Residential	kWh	29,571,590	$ 56,295	0.0019	$/kWh
General Service < 50	kWh	13,780,542	$ 26,234	0.0019	$/kWh
General Service > 50	kW	451,980	$ 339,478	0.7511	$/kW
USL	kWh	-	$ -	-	$/kWh
Sentinel Lights	kW	-	$ -	-	$/kW
Street Lights	kW	-	$ -	-	$/kW
		-	$ -	-	
		-	$ -	-	
Total			**$ 422,007**		

10.0 GREEN ENERGY ACT PLAN

10.1 Is PUCDI's Green Energy Act Plan, including the Smart Grid component of the plan appropriate?

Status:	**Complete Settlement**
Supporting Parties:	PUCDI, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 2, Tab 3, Schedule 5 Board Staff Interrogatory 2-Staff-15 VECC Interrogatory 4-VECC-28

For the purposes of settlement, the Parties accept PUCDI's basic Green Energy Act Plan. The 2013 Cost of Service Rate Application does not include any rate riders, capital expenditures, or OM&A costs relating to the Green Energy Act.

Appendix A -- Summary of Significant Changes

	Original Application (A)	Settlement Agreement (B)	Difference (B)-(A)
Rate Base			
Gross Fixed Assets (average)	134,901,466	132,327,511	(2,573,955)
Accumulated Depreciation (average)	(52,587,960)	(51,060,741)	1,527,219
Allowance for Working Capital:			
Controllable Expenses	10,928,870	9,952,946	(975,924)
Cost of Power	63,539,559	67,087,680	3,548,121
Working Capital Rate (%)	13%	12%	-1%
Utility Income			
Operating Revenues:			
Distribution Revenue at Current Rates	14,769,498	14,811,517	42,019
Distribution Revenue at Proposed Rates	17,944,453	16,241,349	(1,703,104)
Other Revenue			
Other Distribution Revenue	2,267,964	2,600,000	332,036
Total Revenue Offsets	2,267,964	2,600,000	332,036
Operating Expenses			
OM+A Expenses	10,928,870	9,952,946	(975,924)
Depreciation/Amortization	3,302,877	3,331,173	28,296
Taxes/PILs			
Taxable Income			
Adjustments required to arrive at taxable	(2,418,659.00)	(2,389,535)	29,124
Utility Income Taxes and Rates:			
Income taxes (not grossed up)	213,384	193,335	(20,049)
Income taxes (grossed up)	276,280	249,265	(27,015)
Combined tax rate (%)	22.77%	22.44%	-0.33%
Capitalization/Cost of Capital			
Capital Structure:			
Long-term debt Capitalization Ratio (%)	56%	56%	-
Short-term debt Capitalization Ratio (%)	4%	4%	-
Common Equity Capitalization Ratio (%)	40%	40%	-
	100%	100%	
Cost of Capital			
Long-term debt Cost Rate (%)	4.41%	3.91%	-0.50%
Short-term debt Cost Rate (%)	2.08%	2.07%	-0.01%
Common Equity Cost Rate (%)	9.12%	8.98%	-0.14%

Appendix A (Continued): Summary of Significant Changes

Ref.	Item	Reg. Return on Capital	Reg. Rate of Return	Rate Base	Working Capital	Working Capital Allowance	Amortization	PILs	OM&A	Service Rev. Requirement	Base Revenue Requirement	Gross Deficiency
	Original Sub. Nov. 6, 2012	5,704,389	6.20%	91,994,402	74,468,429	9,680,896	3,302,877	276,281	10,928,870	20,212,417	17,944,453	3,174,855
IR2-EP-11	Cost of Power	5,732,990	6.20%	92,455,658	78,016,550	10,142,152	3,302,877	281,241	10,928,870	20,245,978	17,978,014	3,208,416
	Change	28,601	0.00%	461,256	3,548,121	461,256	-	4,960	-	33,561	33,561	33,561
Feb. 14, 2013 OEB Decision	Cost of Capital Parameters	5,530,697	5.98%	92,455,658	78,016,550	10,142,152	3,302,877	263,796	10,928,870	20,028,424	17,760,460	2,990,862
	Change	(202,293)	-0.22%	-	-	-	-	(17,445)	-	(217,554)	(217,554)	(217,554)
3-Staff-24 3-VECC-19	CDM savings Adjustment	5,530,697	5.98%	92,455,658	78,016,550	10,142,152	3,302,877	263,796	10,928,870	20,028,424	17,760,460	2,957,892
	Change	-	0.00%	-	-	-	-	-	-	-	-	(32,970)
4-Staff 40 4-VECC-41	LRAM Rate Rider	5,530,697	5.98%	92,455,658	78,016,550	10,142,152	3,302,877	263,796	10,928,870	20,028,424	17,760,460	2,957,892
	Change	-	0.00%	-	-	-	-	-	-	-	-	-
7-Staff-47 7-Staff-48	Cost allocation meter reading	5,530,697	5.98%	92,455,658	78,016,550	10,142,152	3,302,877	263,796	10,928,870	20,028,424	17,760,460	2,957,892
	Change	-	0.00%	-	-	-	-	-	-	-	-	-
8-Staff-50 8-VECC-38	RTSR,WMS, RRPR Rate Changes	5,530,697	5.98%	92,455,658	78,016,550	10,142,152	3,302,877	263,796	10,928,870	20,028,424	17,760,460	2,957,892
	Change	-	0.00%	-	-	-	-	-	-	-	-	-
9-Staff-51	Primary Metered Loss Factor	5,530,697	5.98%	92,455,658	78,016,550	10,142,152	3,302,877	263,796	10,928,870	20,028,424	17,760,460	2,957,892
	Change	-	0.00%	-	-	-	-	-	-	-	-	-
9-Staff-52	HST/OVAT Disposition Amount	5,530,697	5.98%	92,455,658	78,016,550	10,142,152	3,302,877	263,796	10,928,870	20,028,424	17,760,460	2,957,892
	Change	-	0.00%	-	-	-	-	-	-	-	-	-
9-Staff-54	KWs used for Global Adj. sub account dispoition	5,530,697	5.98%	92,455,658	78,016,550	10,142,152	3,302,877	263,796	10,928,870	20,028,424	17,760,460	2,957,892
	Change	-	0.00%	-	-	-	-	-	-	-	-	-
9-Staff-58 9-Staff-59 9-EP-24	withdraw of 1575 and request for 1576	5,530,697	5.98%	92,455,658	78,016,550	10,142,152	3,323,668	263,796	10,928,870	20,047,031	17,779,067	2,976,499
	Change	-	0.00%	-	-	-	20,791	-	-	18,607	18,607	18,607
Settlement		5,307,965	5.86%	90,511,645	77,040,626	9,244,875	3,331,179	249,265	9,952,946	18,841,349	16,241,349	1,429,832
Change Settlement vs. Original Application		(396,424)	-0.34%	(1,482,757)	2,572,197	(436,021)	28,302	(27,016)	(975,924)	(1,371,068)	(1,703,104)	(1,745,023)

Appendix B – Continuity Tables & Transitional PP&E Amounts (Updated)

As at December 31, 2012			Adjusted for 2012 Actuals and removal of Stranded Meters in 2012 as per settlement agreement								
Appendix 2-B			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions 1/2 year rule**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	89,159	8,433		97,592	0			0	97,592
CEC	1806	Land Rights	836,582			836,582	0			0	836,582
47	1808	Buildings and Fixtures	1,242,326	22,916,497		24,158,823	673,569	254,002		927,571	23,231,252
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally Prima	8,312,486	442,023		8,754,509	3,249,660	213,018		3,462,678	5,291,831
47	1820	Distribution Station Equipment - Normally Prima	9,490,317	1,158,545		10,648,862	6,253,859	174,703		6,428,562	4,220,300
47	1825	Storage Battery Equipment	19,241			19,241	4,241	1,786		6,027	13,214
47	1830	Poles, Towers and Fixtures	13,413,491	1,453,464		14,866,955	2,877,014	282,222		3,159,236	11,707,719
47	1835	Overhead Conductors and Devices	11,917,662	1,368,570		13,286,232	1,407,870	195,464		1,603,334	11,682,898
47	1840	Underground Conduit	11,202,705	332,905		11,535,610	9,755,948	54,632		9,810,580	1,725,030
47	1845	Underground Conductors and Devices	19,409,591	597,638		20,007,229	11,441,337	549,529		11,990,866	8,016,363
47	1850	Line Transformers	15,659,949	1,124,624		16,784,573	7,540,451	690,683		8,231,134	8,553,439
47	1855	Services	3,623,556	449,032		4,072,588	303,293	93,219		396,512	3,676,076
47	1860	Meters	4,478,779		4,437,111	41,668	2,925,195	178,573	3,087,554	16,214	25,454
47	1860	Smart Meters	5,913,667	215,408		6,129,075	1,214,530	402,066		1,616,596	4,512,479
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	0			0	0			0	0
10	1920	Computer Equipment - Hardware	13,578			13,578	8,841	2,786		11,627	1,951
10	1920	Computer Equipment - Hardware - Smart Meters	11,760			11,760	5,232	2,331		7,563	4,197
12	1925	Computer Software	38,397	24,216		62,613	38,368	2,451		40,819	21,794
12	1925	Computer Software Smart Meters	492,267			492,267	256,817	98,104		354,921	137,346
10	1930	Transportation Equipment	0			0	0			0	0
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	0			0	0			0	(0)
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Customer Premise	27,832		(27,832)	0	7,418		7,418	0	0
47	1975	Load Management Controls - Utility Premises	0			0	0			0	0
47	1980	System Supervisory Equipment	3,887,894	305,143		4,193,037	2,572,803	137,836		2,710,639	1,482,398
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(6,887,259)	(785,327)		(7,672,586)	(1,281,741)	(142,964)		(1,424,705)	(6,247,881)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**103,193,980**	**29,611,171**	**4,409,279**	**128,340,208**	**49,254,705**	**3,190,442**	**3,094,972**	**49,350,175**	**78,990,033**
WIP		Work in Process	4,099,831	(4,099,831)		0	0			0	0
		Total after Work in Process	**107,293,811**	**25,511,340**	**4,409,279**	**128,340,208**	**49,254,705**	**3,190,442**	**3,094,972**	**49,350,175**	**78,990,033**
	1925	Transportation						0			
	1930	Stores Equipment									
								3,190,442			

Appendix 2-B			**Cost**				**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions 1/2 year rule**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	97,592			97,592	0			0	97,592
CEC	1806	Land Rights	836,582			836,582	0			0	836,582
47	1808	Buildings and Fixtures	24,158,823			24,158,823	927,571	483,166		1,410,737	22,748,086
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally Prima	8,754,509	46,618		8,801,127	3,462,678	219,126		3,681,804	5,119,323
47	1820	Distribution Station Equipment - Normally Prima	10,648,862	1,471,797		12,120,659	6,428,562	207,582		6,636,144	5,484,515
47	1825	Storage Battery Equipment	19,241			19,241	6,027	1,786		7,812	11,429
47	1830	Poles, Towers and Fixtures	14,866,955	1,240,039		16,106,994	3,159,236	312,150		3,471,386	12,635,608
47	1835	Overhead Conductors and Devices	13,286,232	1,867,384		15,153,616	1,603,334	222,430		1,825,764	13,327,852
47	1840	Underground Conduit	11,535,610	159,833		11,695,443	9,810,580	59,560		9,870,140	1,825,303
47	1845	Underground Conductors and Devices	20,007,229	1,358,580		21,365,809	11,990,866	573,984		12,564,850	8,800,959
47	1850	Line Transformers	16,784,573	159,833		16,944,406	8,231,134	706,738		8,937,872	8,006,534
47	1855	Services	4,072,588	2,049,861		6,122,449	396,512	124,455		520,967	5,601,482
47	1860	Meters	41,668			41,668	16,214	1,600		17,814	23,854
47	1860	Smart Meters	6,129,075	319,666		6,448,741	1,616,596	414,024		2,030,620	4,418,121
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	0			0	0			0	0
10	1920	Computer Equipment - Hardware	13,578			13,578	11,627	1,951		13,578	(0)
10	1920	Computer Equipment - Hardware - Smart Meters	11,760			11,760	7,563	2,331		9,894	1,866
12	1925	Computer Software	62,613			62,613	40,819	4,872		45,691	16,922
12	1925	Computer Software - Smart Meters	492,267			492,267	354,921	98,104		453,025	39,242
10	1930	Transportation Equipment	0			0	0			0	0
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	0			0	0			0	(0)
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	(0)
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Customer Premise	0			0	0			0	0
47	1975	Load Management Controls - Utility Premises	0			0	0			0	0
47	1980	System Supervisory Equipment	4,193,037	266,389		4,459,426	2,710,639	152,124		2,862,763	1,596,663
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(7,672,586)	(965,395)		(8,637,981)	(1,424,705)	(164,850)		(1,589,555)	(7,048,426)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	128,340,208	7,974,605		136,314,813	49,350,175	3,421,131	0	52,771,308	83,543,505
			0			0				0	0
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	128,340,208	**7,974,605**	**0**	**136,314,813**	**49,350,175**	**3,421,131**	**0**	**52,771,308**	**83,543,505**

	1935	Transportation					**PP&E Deferral**	72,876			
	1945	Stores Equipment						0			
								3,348,255			

Appendix B – Continuity Tables & Transitional PP&E Amounts (Updated) - Continued

1576 values Assuming "Previous" CGAAP Accounting Policies continued		
Opening Net PP&E		53,939,275
Additions		30,274,599
Depreciation		-4,145,373
NBV of Disposals		-20,414
Removal of NBV of Stranded Meters		-1,349,557
Closing net PP&E		78,698,530
PP&E Values Assuming Accounting Changes Under CGAAP in 2012		
Opening Net PP&E		53,939,275
Additions		29,611,170
Depreciation		-3,190,442
NBV of Disposals		-20,414
Removal of NBV of Stranded Meters		-1,349,557
Closing net PP&E		78,990,032
Difference in Closing net PP&E, "previous" CGAAP vs "changed" CGAAP		-291,502
Redcution in Depreciation Expense Amortized over 4 years		-72,876
Return on revenue requirement based on WACC (reduction in service revenue requirement)		-17,082

Appendix C – Cost of Power Calculation (Updated)

Electricity - Commodity - RPP	**2013 Forecasted Metered kWhs**	**2013 Loss Factor**			
Class per Load Forecast				**2013**	
Residential	305,688,741	1.0489	320,636,921	$0.07932	$25,432,921
Residential - Non-RPP	33,583,927	1.0489	35,226,181	$0.08001	$2,818,447
General Service < 50	86,296,784	1.0489	90,516,696	$0.07932	$7,179,784
General Service < 50 Non-RPP	15,793,342	1.0489	16,565,637	$0.08001	$1,325,417
General Service > 50	49,251,626	1.0489	51,660,031	$0.07932	$4,097,674
General Service >50 Non-RPP	202,160,454	1.0489	212,046,100	$0.08001	$16,965,808
USL	872,123	1.0489	914,770	$0.07932	$72,560
Sentinel Lights	253,942	1.0489	266,360	$0.08001	$21,311
Street Lights	7,900,227	1.0489	8,286,548	$0.08001	$663,007
TOTAL	**701,801,166**		**727,566,335**		**$58,576,928**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	355,863,102	$0.0066	$2,348,696
General Service < 50		kWh	107,082,333	$0.0061	$653,202
General Service > 50		kW	627,735	$2.4921	$1,564,378
USL		kWh	914,770	$0.0061	$5,580
Sentinel Lights		kW	710	$1.8891	$1,341
Street Lights		kW	22,660	$1.8795	$42,589
TOTAL					**$4,615,788**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	355,863,102	$0.0000	$0
General Service < 50		kWh	107,082,333	$0.0000	$0
General Service > 50		kW	627,735	$0.0000	$0
USL		kWh	228,508	$0.0000	$0
Sentinel Lights		kW	710	$0.0000	$0
Street Lights		kW	22,660	$0.0000	$0
TOTAL					**$0**

Wholesale Market Service		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	355,863,102	$0.0044	$1,565,798
General Service < 50		kWh	107,082,333	$0.0044	$471,162
General Service > 50		kWh	212,046,100	$0.0044	$933,003
USL		kWh	914,770	$0.0044	$4,025
Sentinel Lights		kWh	266,360	$0.0044	$1,172
Street Lights		kWh	8,286,548	$0.0044	$36,461
TOTAL					**$3,011,621**

Rural Rate Assistance		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	355,863,102	$0.0012	$427,036
General Service < 50		kWh	107,082,333	$0.0012	$128,499
General Service > 50		kWh	263,706,131	$0.0012	$316,447
USL		kWh	914,770	$0.0012	$1,098
Sentinel Lights		kWh	266,360	$0.0012	$320
Street Lights		kWh	8,286,548	$0.0012	$9,944
TOTAL					**$883,343**

Low Voltage		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	355,863,102	$0.0000	$0
General Service < 50		kWh	107,082,333	$0.0000	$0
General Service > 50		kW	44,045	$0.0000	$0
USL		kWh	228,508	$0.0000	$0
Sentinel Lights		kW	710	$0.0000	$0
Street Lights		kW	22,660	$0.0000	$0
TOTAL					**$0**

	2013	
4705-Power Purchased	$58,576,928	
4708-Charges-WMS	$3,011,621	
4714-Charges-NW	$4,615,788	
4716-Charges-CN	$0	
4730-Rural Rate Assistance	$883,343	included in 4708
4750-Low Voltage	$0	
TOTAL	**67,087,680**	

Appendix D – 2013 Customer Load Forecast (Updated)

PUC Distribution Weather Normal Load Forecast for 2013 Rate Application

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Weather Normal	2013 Weather Normal (including CDM Adjustment)
Actual kWh Purchases	755,126,020	757,685,752	749,219,032	728,093,333	738,093,576	740,966,486	732,869,984	714,199,062	745,049,194		
Predicted kWh Purchases	752,186,605	747,941,289	742,744,460	722,674,603	739,500,414	748,042,540	745,709,118	726,958,624	735,544,787	741,365,477	735,002,223
% Difference	-0.4%	-1.3%	-0.9%	-0.7%	0.2%	1.0%	1.8%	1.8%	-1.3%		
Billed kWh	719,286,098	727,308,120	717,783,995	697,140,805	701,800,772	710,698,626	707,756,700	683,757,862	711,929,017	709,771,503	703,408,249
By Class											
Residential											
Customers	28,544	28,560	28,576	28,596	28,630	28,780	28,971	29,057	29,124	29,197	29,271
kWh	351,037,890	356,490,492	347,274,259	335,395,539	338,874,337	347,363,230	348,619,359	326,493,714	345,282,279	343,919,087	340,561,450
General Service < 50											
Customers	3,230	3,247	3,274	3,301	3,302	3,325	3,352	3,345	3,366	3,383	3,401
kWh	96,164,282	95,721,847	95,591,622	86,770,873	94,225,468	93,474,158	91,450,221	91,377,364	101,728,299	102,252,688	102,179,766
General Service >50											
Customers	419	424	431	432	429	426	433	435	403	401	399
kWh	263,763,186	266,586,772	266,071,754	266,238,407	259,930,403	261,123,945	258,998,141	257,036,820	255,968,368	254,567,184	251,632,820
kW	659,827	673,069	682,195	657,827	657,184	650,699	637,622	635,104	629,024	635,612	628,286
USL											
Customers	12	19	27	28	27	22	17	16	19	20	21
kWh	851,637	842,654	845,827	856,153	863,982	848,325	823,448	837,229	874,873	877,822	872,889
Sentinel Lights											
Connections	466	466	459	449	443	435	423	411	402	395	387
kWh	276,562	291,228	281,406	274,009	269,054	268,763	262,522	258,147	260,362	258,405	254,165
kW	768	873	784	766	747	744	730	714	703	722	710
Street Lights											
Connections	8,619	8,635	8,642	8,663	8,707	8,741	8,799	8,846	8,846	8,875	8,904
kWh	7,192,541	7,375,127	7,719,127	7,605,824	7,637,528	7,620,205	7,603,009	7,754,588	7,814,836	7,896,317	7,907,160
kW	21,295	21,340	21,295	23,029	21,406	21,317	21,346	23,264	21,619	22,649	22,680
Total of Above											
Customer/Connections	41,290	41,351	41,409	41,469	41,538	41,729	41,995	42,110	42,160	42,271	42,383
kWh	719,286,098	727,308,120	717,783,995	697,140,805	701,800,772	710,698,626	707,756,700	683,757,862	711,929,017	709,771,503	703,408,247
kW from applicable classes	681,890	695,282	704,274	681,622	679,337	672,760	659,698	659,082	651,346	658,984	651,676
Total from Model											
Customer/Connections	41,290	41,351	41,409	41,469	41,538	41,729	41,995	42,110	42,160	42,271	42,383
kWh	719,286,098	727,308,120	717,783,995	697,140,805	701,800,772	710,698,626	707,756,700	683,757,862	711,929,017	709,771,503	703,408,247
kW from applicable classes	681,890	695,282	704,274	681,622	679,337	672,760	659,698	659,082	651,346	658,984	651,676

Appendix E – Debt and Capital Structure (Updated)

Debt & Capital Cost Structure

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Note Payable	PUC Inc.	Y		26,534,040		6.00%	2008	1,592,042
Loan Payable	Infrastructure Ontario	N		3,500,000		1.75%	2009	61,250
Note Payable	PUC Inc.	Y		26,534,040		6.00%	2009	1,592,042
Note Payable	PUC Inc.	Y		26,534,040		6.00%	2010	1,592,042
Loan Payable	Ontario Infrastructure	N		5,000,000		1.75%	2010	87,500
Note Payable	PUC Inc.	Y		26,534,040		6.00%	2011	1,592,042
Loan Payable	Ontario Infrastructure	N		5,000,000		1.75%	2011	87,500
Loan Payable	Ontario Infrastructure	N		1,092,003		1.75%	2011	19,110
Note Payable	PUC Inc.	Y		26,534,040		6.00%	2012	1,592,042
Loan Payable	Ontario Infrastructure	N		25,000,000		1.75%	2012	437,500
Loan Payable	Ontario Infrastructure	N		20,000,000		3.79%	2013	758,000
				5,000,000		3.29%	2013	164,500
Note Payable	PUC Inc.	Y		26,534,040		4.12%	2013	1,093,202
								0
								0
								0
								0
								0
								0
								0
								0
								0

2008 Total Long Term Debt	26,534,040	Total Interest Cost for 2008	1,592,042
		Weighted Debt Cost Rate for 2008	6.00%
2009 Total Long Term Debt	30,034,040	Total Interest Cost for 2009	1,653,292
		Weighted Debt Cost Rate for 2009	5.50%
2010 Total Long Term Debt	31,534,040	Total Interest Cost for 2010	1,679,542
		Weighted Debt Cost Rate for 2010	5.33%
2011 Total Long Term Debt	51,534,040	Total Interest Cost for 2011	1,698,652
		Weighted Debt Cost Rate for 2011	3.30%
2012 Total Long Term Debt	51,534,040	Total Interest Cost for 2012	2,029,542
		Weighted Debt Cost Rate for 2012	3.94%
2013 Total Long Term Debt	51,534,040	Total Interest Costs for 2013	2,015,702
		Weighted Debt Cost Rate for 2013	3.91%

Appendix E – Debt and Capital Structure (Updated)

Deemed Capital Structure for 2012

Description	$	% of Rate Base (Capitalization Ratio)	Rate of Return (Cost Rate)	Return
Long Term Debt	43,504,566	56.00%	6.10%	2,653,779
Unfunded Short Term Debt	3,107,469	4.00%	4.47%	138,904
Total Debt	46,612,035	60.00%		2,792,682
Common Share Equity	31,074,690	40.00%	8.57%	2,663,101
Total equity	31,074,690	40.00%		2,663,101
Total Rate Base	77,686,725	100.00%	7.02%	5,455,783

Deemed Capital Structure for 2013

Description	$	% of Rate Base (Capitalization Ratio)	Rate of Return (Cost Rate)	Return
Long Term Debt	50,686,521	56.00%	3.91%	1,981,843
Unfunded Short Term Debt	3,620,466	4.00%	2.07%	74,944
Total Debt	54,306,987	60.00%		2,056,787
Common Share Equity	36,204,658	40.00%	8.98%	3,251,178
Total equity	36,204,658	40.00%		3,251,178
Total Rate Base	90,511,645	100.00%	5.86%	5,307,965

Appendix F – 2013 PILS (Updated)

PILs Tax Provision - Test Year

						Wires Only	
Regulatory Taxable Income						$ 861,642	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 99,089	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction	-7.00%	**E**	-$ 35,000	**F = D * E**		
Ontario Income tax						$ 64,089	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			7.44%	**K = J / A**		
	Federal tax rate			15.00%	**L**		
	Combined tax rate					22.44%	**M = K + L**
Total Income Taxes						**$ 193,335**	**N = A * M**
Investment Tax Credits							**O**
Miscellaneous Tax Credits							**P**
Total Tax Credits						**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**$ 193,335**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				77.56%	**S = 1 - M**	**$ 55,930**	**T = R / S - R**
Income Tax (grossed-up)						**$ 249,265**	**U = R + T**

Appendix G – 2013 Cost of Capital (Updated)

Deemed Capital Structure

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
		2013 Test Year				
		Application				
	Debt					
1	Long-term Debt	56.00%		$50,686,521	3.91%	$1,981,843
2	Short-term Debt	4.00%	(1)	$3,620,466	2.07%	$74,944
3	**Total Debt**	60.0%		$54,306,987	3.79%	$2,056,787
	Equity					
4	Common Equity	40.00%		$36,204,658	8.98%	$3,251,178
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$36,204,658	8.98%	$3,251,178
7	**Total**	100.0%		$90,511,645	5.86%	$5,307,965

Notes

Capital Structure

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
1	Loan Payable	Ontario Infrastructure	Third-Party				$ 20,000,000	3.79%	$ 758,000
2	Loan Payable	Ontario Infrastructure	Third-Party				$ 5,000,000	3.29%	$ 164,500
3	Note Payable	Note Payable	Affiliated				$ 26,534,040	4.12%	$ 1,093,202
4									$ -
Total							$ 51,534,040	3.91%	$ 2,015,702

Appendix H – 2013 Revenue Deficiency (Updated)

PUC Distribution Inc.
Revenue Deficiency Determination

Description	2013 Test Existing Rates	2013 Test - Required Revenue
Revenue		
Revenue Deficiency		**1,429,833**
Distribution Revenue	14,811,517	14,811,517
Other Operating Revenue (Net)	2,600,000	2,600,000
Total Revenue	**17,411,517**	**18,841,350**
Costs and Expenses		
Administrative & General, Billing & Collecting	4,807,560	4,807,560
Operation & Maintenance	5,095,386	5,095,386
Depreciation & Amortization	3,348,256	3,348,256
Property Taxes	50,000	50,000
Return on PP&E	(17,082)	(17,082)
Deemed Interest	2,056,787	2,056,787
Total Costs and Expenses	**15,340,907**	**15,340,907**
Less OCT Included Above	0	0
Total Costs and Expenses Net of OCT	**15,340,907**	**15,340,907**
Utility Income Before Income Taxes	**2,070,610**	**3,500,443**
Income Taxes:		
Corporate Income Taxes	0	249,265
Total Income Taxes	**0**	**249,265**
Utility Net Income	**2,070,610**	**3,251,178**
Capital Tax Expense Calculation:		
Total Rate Base	90,511,645	90,511,645
Exemption	15,000,000	15,000,000
Deemed Taxable Capital	**75,511,645**	**75,511,645**
Ontario Capital Tax	0	0
Income Tax Expense Calculation:		
Accounting Income	2,070,610	3,500,443
Tax Adjustments to Accounting Income	(2,389,535)	(2,389,535)
Taxable Income	**(318,925)**	**1,110,908**
Income Tax Expense	0	249,265
Tax Rate Refecting Tax Credits		
Actual Return on Rate Base:		
Rate Base	90,511,645	90,511,645
Interest Expense	2,056,787	2,056,787
Net Income	2,070,610	3,251,178
Total Actual Return on Rate Base	**4,127,397**	**5,307,965**
Actual Return on Rate Base	4.56%	5.86%
Required Return on Rate Base:		
Rate Base	90,511,645	90,511,645
Return Rates:		
Return on Debt (Weighted)	3.79%	3.79%
Return on Equity	8.98%	8.98%
Deemed Interest Expense	2,056,787	2,056,787
Return On Equity	3,251,178	3,251,178
Total Return	**5,307,965**	**5,307,965**
Expected Return on Rate Base	5.86%	5.86%
Revenue Deficiency After Tax	**1,180,568**	
Revenue Deficiency Before Tax	**1,429,833**	

Tax Exhibit		**2013**
Deemed Utility Income		3,251,178
Tax Adjustments to Accounting Income		(2,389,535)
Taxable Income prior to adjusting revenue to PILs		**861,643**
Tax Rate		22.44%
Total PILs before gross up		**193,335**
Grossed up PILs		**249,265**

Appendix I – Proposed 2013 Schedule of Rates and Charges (Updated)

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date July 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0162

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a single family unit, non-commercial. This can be a separately metered living accommodation, town house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning. Further servicing details are available in the distributor's Conditions of Service.

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	9.66
Rate Rider for Recovery of Stranded Meter Assets - effective until April 30, 2014	$	3.39
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0167
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) - effective until April 30, 2014	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2014	$/kWh	(0.0053)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0019
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date July 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0162

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	16.45
Rate Rider for Recovery of Stranded Meter Assets - effective until April 30, 2014	$	9.76
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0197
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism (LRAM) - effective until April 30, 2014	$/kWh	0.0002
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2011 CDM Activities) - effective until April 30, 2014	$/kWh	0.0001
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2014	$/kWh	(0.0049)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0019
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date July 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0162

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly peak demand used for billing purposes over the past 12 months is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	110.00
Rate Rider for Recovery of Stranded Meter Assets - Effective until April 30, 2014	$	6.52
Distribution Volumetric Rate	$/kW	5.2254
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM)- Effective until April 30, 2014	$/kW	0.0151
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2011 CDM Activities) - effective until April 30, 2014	$/kW	0.0222
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2014	$/kW	(1.8699)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.7511
Retail Transmission Rate – Network Service Rate	$/kW	2.2434
Retail Transmission Rate – Network Service Rate - Interval Metered	$/kW	2.8214

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date July 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0162

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	12.20
Distribution Volumetric Rate	$/kWh	0.0299
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2014	$/kWh	(0.0049)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date July 1, 2013

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EB-2012-0162

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential or General Service customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.82
Distribution Volumetric Rate	$/kW	26.2894
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2014	$/kW	(4.6117)
Retail Transmission Rate – Network Service Rate	$/kW	1.7006

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date July 1, 2013

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EB-2012-0162

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.83
Distribution Volumetric Rate	$/kW	18.4267
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2014	$/kW	(4.5230)
Retail Transmission Rate – Network Service Rate	$/kW	1.6919

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date July 1, 2013

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EB-2012-0162

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date July 1, 2013

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EB-2012-0162

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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Customer Administration

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

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge – At Meter After Hours	$	185.00
Disconnect/Reconnect Charge – At Pole During Regular Hours	$	185.00
Disconnect/Reconnect Charge – At Pole After Hours	$	415.00

Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Service call - customer-owned equipment		Time & materials
Service call - after regular hour		Time & materials
Temporary service install & remove - overhead - no transformer		Time & materials
Temporary service install & remove - underground - no transformer		Time & materials
Temporary service install & remove - overhead - with transformer		Time & materials
Removal of overhead lines – during regular hours		Time & materials
Removal of overhead lines – after hours		Time & materials
Roadway escort – after regular hours		Time & materials
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date July 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0162

RETAIL SERVICE CHARGES (if applicable)

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

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

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

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

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0489
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0385

Appendix J - Updated Customer Impact – Residential (Updated)

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 966 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed af

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 8.8100	1	$ 8.81	$ 9.6600	1	$ 9.66	$ 0.85	9.65%
Smart Meter Disposition Rider	Monthly	$ 3.0300	1	$ 3.03		1	$ -	-$ 3.03	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 3.3900	1	$ 3.39	$ 3.39	
SME Charge Rate Rider	Monthly		1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	966	$ 14.68	$ 0.0167	966	$ 16.13	$ 1.45	9.87%
			966	$ -		966	$ -	$ -	
LRAM	per kWh	$ 0.0015	966	$ 1.45	$ 0.0004	966	$ 0.39	-$ 1.06	-73.33%
	per kWh		966	$ -		966	$ -	$ -	
			966	$ -		966	$ -	$ -	
			966	$ -		966	$ -	$ -	
			966	$ -		966	$ -	$ -	
			966	$ -		966	$ -	$ -	
			966	$ -		966	$ -	$ -	
			966	$ -		966	$ -	$ -	
Sub-Total A				$ 27.97			$ 30.36	**$ 2.39**	**8.53%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	966	-$ 1.26	-$ 0.0053	966	-$ 5.12	-$ 3.86	307.69%
			966	$ -		966	$ -	$ -	
			966	$ -		966	$ -	$ -	
			966	$ -		966	$ -	$ -	
Low Voltage Service Charge			966	$ -		966	$ -	$ -	
Smart Meter Entity Charge						966	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.72**			**$ 25.24**	**-$ 1.48**	**-5.53%**
RTSR - Network	per kWh	$ 0.0066	1010	$ 6.67	$ 0.0059	1013	$ 5.98	-$ 0.69	-10.31%
RTSR - Line and Transformation Connection			1010	$ -		1013	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.38**			**$ 31.22**	**-$ 2.16**	**-6.48%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	1010	$ 5.25	$ 0.0044	1013	$ 4.46	-$ 0.79	-15.10%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	1010	$ 1.11	$ 0.0012	1013	$ 1.22	$ 0.11	9.46%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0020	1010	$ 2.02	$ 0.0020	1013	$ 2.03	$ 0.01	0.33%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	410	$ 36.07	$ 0.0880	413	$ 36.36	$ 0.30	0.82%
TOU - Off Peak		$ 0.0650	646	$ 42.01	$ 0.0650	648	$ 42.15	$ 0.14	0.33%
TOU - Mid Peak		$ 0.1000	182	$ 18.18	$ 0.1000	182	$ 18.24	$ 0.06	0.33%
TOU - On Peak		$ 0.1170	182	$ 21.27	$ 0.1170	182	$ 21.34	$ 0.07	0.33%
Total Bill on RPP (before Taxes)				**$ 123.08**			**$ 120.53**	**-$ 2.55**	**-2.07%**
HST		13%		$ 16.00	13%		$ 15.67	-$ 0.33	-2.07%
Total Bill (including HST)				$ 139.08			$ 136.20	-$ 2.88	-2.07%
Ontario Clean Energy Benefit [1]				-$ 13.91			-$ 13.62	$ 0.29	-2.08%
Total Bill on RPP (including OCEB)				**$ 125.17**			**$ 122.58**	**-$ 2.59**	**-2.07%**
Total Bill on TOU (before Taxes)				**$ 123.47**			**$ 120.90**	**-$ 2.57**	**-2.08%**
HST		13%		$ 16.05	13%		$ 15.72	-$ 0.33	-2.08%
Total Bill (including HST)				$ 139.52			$ 136.61	-$ 2.91	-2.08%
Ontario Clean Energy Benefit [1]				-$ 13.95			-$ 13.66	$ 0.29	-2.08%
Total Bill on TOU (including OCEB)				**$ 125.57**			**$ 122.95**	**-$ 2.62**	**-2.08%**

Loss Factor (%) 4.5400% 4.8900%

Appendix J - Updated Customer Impact - General Service < 50 kW (Updated)

Appendix 2-W
Bill Impacts

Customer Class: **General Service < 50**

Consumption 2000 **kWh** ◉ May 1 - October 31 ◯ November 1 - April 30 (Select this radio button for applications filed af

	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	$ 15.0000	1	$ 15.00	$ 16.4500	1	$ 16.45	$ 1.45	9.67%
Smart Meter Disposition Rider	Monthly	$ 18.3800	1	$ 18.38		1	$ -	-$ 18.38	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 9.7600	1	$ 9.76	$ 9.76	
SME Charge Rate Rider	Monthly		1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0180	2000	$ 36.00	$ 0.0197	2000	$ 39.40	$ 3.40	9.44%
			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0001	2000	$ 0.20		2000	$ -	-$ 0.20	-100.00%
LRAM			2000	$ -	$ 0.0002	2000	$ 0.40	$ 0.40	
LRAMVA			2000	$ -	$ 0.0001	2000	$ 0.20	$ 0.20	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 69.58			$ 67.00	**-$ 2.58**	**-3.71%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0013	2000	-$ 2.60	-$ 0.0049	2000	-$ 9.80	-$ 7.20	276.92%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Low Voltage Service Charge			2000	$ -		2000	$ -	$ -	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 66.98**			**$ 57.20**	**-$ 9.78**	**-14.60%**
RTSR - Network	per kWh	$ 0.0061	2091	$ 12.75	$ 0.0055	2098	$ 11.54	-$ 1.22	-9.53%
RTSR - Line and Transformation Connection			2091	$ -		2098	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 79.73**			**$ 68.74**	**-$ 11.00**	**-13.79%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2091	$ 10.87	$ 0.0044	2098	$ 9.23	-$ 1.64	-15.10%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2091	$ 2.30	$ 0.0012	2098	$ 2.52	$ 0.22	9.46%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0020	2091	$ 4.18	$ 0.0020	2098	$ 4.20	$ 0.01	0.33%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	1491	$ 131.19	$ 0.0880	1498	$ 131.81	$ 0.62	0.47%
TOU - Off Peak		$ 0.0650	1338	$ 86.98	$ 0.0650	1343	$ 87.27	$ 0.29	0.33%
TOU - Mid Peak		$ 0.1000	376	$ 37.63	$ 0.1000	378	$ 37.76	$ 0.13	0.33%
TOU - On Peak		$ 0.1170	376	$ 44.03	$ 0.1170	378	$ 44.18	$ 0.15	0.33%
Total Bill on RPP (before Taxes)				**$ 273.53**			**$ 261.74**	**-$ 11.79**	**-4.31%**
HST		13%		$ 35.56	13%		$ 34.03	-$ 1.53	-4.31%
Total Bill (including HST)				$ 309.09			$ 295.76	-$ 13.32	-4.31%
Ontario Clean Energy Benefit [1]				-$ 30.91			-$ 29.58	$ 1.33	-4.30%
Total Bill on RPP (including OCEB)				**$ 278.18**			**$ 266.18**	**-$ 11.99**	**-4.31%**
Total Bill on TOU (before Taxes)				**$ 265.98**			**$ 254.14**	**-$ 11.84**	**-4.45%**
HST		13%		$ 34.58	13%		$ 33.04	-$ 1.54	-4.45%
Total Bill (including HST)				$ 300.56			$ 287.18	-$ 13.38	-4.45%
Ontario Clean Energy Benefit [1]				-$ 30.06			-$ 28.72	$ 1.34	-4.46%
Total Bill on TOU (including OCEB)				**$ 270.50**			**$ 258.46**	**-$ 12.04**	**-4.45%**

Loss Factor (%) 4.5400% (current) 4.8900% (proposed)

Appendix J - Updated Customer Impact - General Service > 50 kW(Updated)

Appendix 2-W
Bill Impacts

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

Consumption 52339 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed aft

131 **kW**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 146.7400	1	$ 146.74	$ 110.00	1	$ 110.00	-$ 36.74	-25.04%
Smart Meter Disposition Rider	Monthly	$ 37.3500	1	$ 37.35		1	$ -	-$ 37.35	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 6.52	1	$ 6.52	$ 6.52	
						1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 4.4234	131	$ 579.47	$ 5.2254	131	$ 684.53	$ 105.06	18.13%
			52339	$ -		52339	$ -	$ -	
LRAM & SSM Rate Rider			52339	$ -		52339	$ -	$ -	
LRAM	per kW		131	$ -	$ 0.0151	131	$ 1.98	$ 1.98	
LRAMVA	per kW		131	$ -	$ 0.0222	131	$ 2.91	$ 2.91	
			52339	$ -		52339	$ -	$ -	
			52339	$ -		52339	$ -	$ -	
			52339	$ -		52339	$ -	$ -	
			52339	$ -		52339	$ -	$ -	
			52339	$ -		52339	$ -	$ -	
Sub-Total A				$ 763.56			$ 805.93	**$ 42.38**	**5.55%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.4259	131	-$ 55.79	-$ 1.8699	131	-$ 244.96	-$ 189.16	339.05%
			52339	$ -		52339	$ -	$ -	
			52339	$ -		52339	$ -	$ -	
			52339	$ -		52339	$ -	$ -	
Low Voltage Service Charge			52339	$ -		52339	$ -	$ -	
Smart Meter Entity Charge						52339	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 707.76**			**$ 560.98**	**-$ 146.79**	**-20.74%**
RTSR - Network	per kW	$ 2.4921	137	$ 341.29	$ 2.2434	137	$ 308.26	-$ 33.03	-9.68%
RTSR - Line and Transformation Connection			54715	$ -			$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,049.05**			**$ 869.23**	**-$ 179.82**	**-17.14%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	54715	$ 284.52	$ 0.0044	54898	$ 241.55	-$ 42.97	-15.10%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	54715	$ 60.19	$ 0.0012	54898	$ 65.88	$ 5.69	9.46%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0020	54715	$ 109.43	$ 0.0020	54898	$ 109.80	$ 0.37	0.33%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	54115	$ 4,762.14	$ 0.0880	54298	$4,778.26	$ 16.12	0.34%
TOU - Off Peak		$ 0.0650	35018	$ 2,276.15	$ 0.0650	35135	$2,283.77	$ 7.62	0.33%
TOU - Mid Peak		$ 0.1000	9849	$ 984.87	$ 0.1000	9882	$ 988.17	$ 3.30	0.33%
TOU - On Peak		$ 0.1170	9849	$ 1,152.30	$ 0.1170	9882	$1,156.16	$ 3.86	0.33%
Total Bill on RPP (before Taxes)				**$ 6,310.57**			**$6,109.97**	**-$ 200.60**	**-3.18%**
HST		13%		$ 820.37	13%		$ 794.30	-$ 26.08	-3.18%
Total Bill (including HST)				$ 7,130.95			$6,904.26	-$ 226.68	-3.18%
Ontario Clean Energy Benefit [1]				-$ 713.09			-$ 690.43	$ 22.66	-3.18%
Total Bill on RPP (including OCEB)				**$ 6,417.86**			**$6,213.83**	**-$ 204.02**	**-3.18%**
Total Bill on TOU (before Taxes)				**$ 5,916.76**			**$5,714.81**	**-$ 201.95**	**-3.41%**
HST		13%		$ 769.18	13%		$ 742.93	-$ 26.25	-3.41%
Total Bill (including HST)				$ 6,685.94			$6,457.74	-$ 228.20	-3.41%
Ontario Clean Energy Benefit [1]				-$ 668.59			-$ 645.77	$ 22.82	-3.41%
Total Bill on TOU (including OCEB)				**$ 6,017.35**			**$5,811.97**	**-$ 205.38**	**-3.41%**

Loss Factor (%) 4.5400% (current) 4.8900% (proposed)

Appendix J - Updated Customer Impact – Unmetered Scattered Load (Updated)

Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption **3450** **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed af

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 11.1300	1	$ 11.13	$ 12.2000	1	$ 12.20	$ 1.07	9.61%
Smart Meter Disposition Rider	Monthly		1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0273	3450	$ 94.19	$ 0.0299	3450	$ 103.16	$ 8.97	9.52%
			3450	$ -		3450	$ -	$ -	
LRAM & SSM Rate Rider			3450	$ -		3450	$ -	$ -	
			3450	$ -		3450	$ -	$ -	
			3450	$ -		3450	$ -	$ -	
			3450	$ -		3450	$ -	$ -	
			3450	$ -		3450	$ -	$ -	
			3450	$ -		3450	$ -	$ -	
			3450	$ -		3450	$ -	$ -	
			3450	$ -		3450	$ -	$ -	
Sub-Total A				$ 105.32			$ 115.36	**$ 10.04**	**9.53%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0014	3450	-$ 4.83	-$ 0.0049	3450	-$ 16.91	-$ 12.08	250.00%
			3450	$ -		3450	$ -	$ -	
			3450	$ -		3450	$ -	$ -	
			3450	$ -		3450	$ -	$ -	
Low Voltage Service Charge			3450	$ -		3450	$ -	$ -	
Smart Meter Entity Charge						3450	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 100.49**			**$ 98.45**	**-$ 2.04**	**-2.03%**
RTSR - Network	per kWh	$ 0.0061	3607	$ 22.00	$ 0.0055	3619	$ 19.90	-$ 2.10	-9.53%
RTSR - Line and Transformation Connection			3607	$ -		3619	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 122.49**			**$ 118.35**	**-$ 4.13**	**-3.37%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	3607	$ 18.75	$ 0.0044	3619	$ 15.92	-$ 2.83	-15.10%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	3607	$ 3.97	$ 0.0012	3619	$ 4.34	$ 0.38	9.46%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0020	3607	$ 7.21	$ 0.0020	3619	$ 7.24	$ 0.02	0.33%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	3007	$ 264.58	$ 0.0880	3019	$ 265.65	$ 1.06	0.40%
TOU - Off Peak		$ 0.0650	2308	$ 150.04	$ 0.0650	2316	$ 150.54	$ 0.50	0.33%
TOU - Mid Peak		$ 0.1000	649	$ 64.92	$ 0.1000	651	$ 65.14	$ 0.22	0.33%
TOU - On Peak		$ 0.1170	649	$ 75.96	$ 0.1170	651	$ 76.21	$ 0.25	0.33%
Total Bill on RPP (before Taxes)				**$ 462.25**			**$ 456.75**	**-$ 5.50**	**-1.19%**
HST		13%		$ 60.09	13%		$ 59.38	-$ 0.72	-1.19%
Total Bill (including HST)				$ 522.35			$ 516.13	-$ 6.22	-1.19%
Ontario Clean Energy Benefit [1]				-$ 52.23			-$ 51.61	$ 0.62	-1.19%
Total Bill on RPP (including OCEB)				**$ 470.12**			**$ 464.52**	**-$ 5.60**	**-1.19%**
Total Bill on TOU (before Taxes)				**$ 443.58**			**$ 437.99**	**-$ 5.59**	**-1.26%**
HST		13%		$ 57.67	13%		$ 56.94	-$ 0.73	-1.26%
Total Bill (including HST)				$ 501.25			$ 494.93	-$ 6.32	-1.26%
Ontario Clean Energy Benefit [1]				-$ 50.12			-$ 49.49	$ 0.63	-1.26%
Total Bill on TOU (including OCEB)				**$ 451.13**			**$ 445.44**	**-$ 5.69**	**-1.26%**

Loss Factor (%) Current: 4.5400% Proposed: 4.8900%

Appendix J - Updated Customer Impact – Sentinel Lighting (Updated)

Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Lights**

Consumption 55 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed aft

0.1522 kW

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 2.5700	1	$ 2.57	$ 2.8200	1	$ 2.82	$ 0.25	9.73%
Smart Meter Disposition Rider	Monthly		1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 23.9750	0.1522	$ 3.65	$ 26.2894	0.1522	$ 4.00	$ 0.35	9.65%
			55	$ -		55	$ -	$ -	
LRAM & SSM Rate Rider			55	$ -		55	$ -	$ -	
			55	$ -		55	$ -	$ -	
			55	$ -		55	$ -	$ -	
			55	$ -		55	$ -	$ -	
			55	$ -		55	$ -	$ -	
			55	$ -		55	$ -	$ -	
			55	$ -		55	$ -	$ -	
			55	$ -		55	$ -	$ -	
Sub-Total A				$ 6.22			$ 6.82	**$ 0.60**	**9.68%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.0438	0.1522	-$ 0.16	-$ 4.6117	0.1522	-$ 0.70	-$ 0.54	341.82%
			55	$ -		55	$ -	$ -	
			55	$ -		55	$ -	$ -	
			55	$ -		55	$ -	$ -	
Low Voltage Service Charge			55	$ -		55	$ -	$ -	
Smart Meter Entity Charge						55	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.06**			**$ 6.12**	**$ 0.06**	**0.98%**
RTSR - Network	per kW	$ 1.8891	0.1592	$ 0.30	$ 1.7006	0.1597	$ 0.27	-$ 0.03	-9.68%
RTSR - Line and Transformation Connection			57	$ -		0	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 6.36**			**$ 6.39**	**$ 0.03**	**0.47%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	57	$ 0.30	$ 0.0044	58	$ 0.25	-$ 0.05	-15.10%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	57	$ 0.06	$ 0.0012	58	$ 0.07	$ 0.01	9.46%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0020	57	$ 0.11	$ 0.0020	58	$ 0.12	$ 0.00	0.33%
Energy - RPP - Tier 1		$ 0.0750	57	$ 4.31	$ 0.0750	58	$ 4.33	$ 0.01	0.33%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	37	$ 2.39	$ 0.0650	37	$ 2.40	$ 0.01	0.33%
TOU - Mid Peak		$ 0.1000	10	$ 1.03	$ 0.1000	10	$ 1.04	$ 0.00	0.33%
TOU - On Peak		$ 0.1170	10	$ 1.21	$ 0.1170	10	$ 1.21	$ 0.00	0.33%
Total Bill on RPP (before Taxes)				**$ 11.40**			**$ 11.41**	**$ 0.01**	**0.05%**
HST		13%		$ 1.48	13%		$ 1.48	$ 0.00	0.05%
Total Bill (including HST)				$ 12.88			$ 12.89	$ 0.01	0.05%
Ontario Clean Energy Benefit [1]				-$ 1.29			-$ 1.29	$ -	0.00%
Total Bill on RPP (including OCEB)				**$ 11.59**			**$ 11.60**	**$ 0.01**	**0.06%**
Total Bill on TOU (before Taxes)				**$ 11.73**			**$ 11.73**	**$ 0.01**	**0.06%**
HST		13%		$ 1.52	13%		$ 1.53	$ 0.00	0.06%
Total Bill (including HST)				$ 13.25			$ 13.26	$ 0.01	0.06%
Ontario Clean Energy Benefit [1]				-$ 1.33			-$ 1.33	$ -	0.00%
Total Bill on TOU (including OCEB)				**$ 11.92**			**$ 11.93**	**$ 0.01**	**0.06%**

	Current	Proposed
Loss Factor (%)	4.5400%	4.8900%

Appendix J - Updated Customer Impact – Street lighting (Updated)

Appendix 2-W
Bill Impacts

Customer Class: **Street Lights #1**

Consumption 363541 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after (

1825 kW

	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	$ 2.5800	8612	$ 22,218.96	$ 2.8300	8612	$ 24,371.96	$ 2,153.00	9.69%
Smart Meter Disposition Rider	Monthly		1	$ -		1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 16.8045	1825	$ 30,668.21	$ 18.4267	1825	$ 33,628.73	$ 2,960.52	9.65%
			363541	$ -		363541	$ -	$ -	
LRAM & SSM Rate Rider			363541	$ -		363541	$ -	$ -	
			363541	$ -		363541	$ -	$ -	
			363541	$ -		363541	$ -	$ -	
			363541	$ -		363541	$ -	$ -	
			363541	$ -		363541	$ -	$ -	
			363541	$ -		363541	$ -	$ -	
			363541	$ -		363541	$ -	$ -	
			363541	$ -		363541	$ -	$ -	
Sub-Total A				$ 52,887.17			$ 58,000.69	**$ 5,113.52**	**9.67%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.7860	1825	-$ 1,434.45	-$ 4.5230	1825	-$ 8,254.48	-$ 6,820.03	475.45%
			363541	$ -		363541	$ -	$ -	
			363541	$ -		363541	$ -	$ -	
			363541	$ -		363541	$ -	$ -	
Low Voltage Service Charge			363541	$ -		363541	$ -	$ -	
Smart Meter Entity Charge						363541	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 51,452.72**			**$ 49,746.21**	**-$ 1,706.51**	**-3.32%**
RTSR - Network	per kW	$ 1.8795	1908	$ 3,585.81	$ 1.6919	1914	$ 3,238.71	-$ 347.11	-9.68%
RTSR - Line and Transformation Connection			380046	$ -		1914	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 55,038.54**			**$ 52,984.92**	**-$ 2,053.62**	**-3.73%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	380046	$ 1,976.24	$ 0.0044	381318	$ 1,677.80	-$ 298.44	-15.10%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	380046	$ 418.05	$ 0.0012	381318	$ 457.58	$ 39.53	9.46%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0020	380046	$ 760.09	$ 0.0020	381318	$ 762.64	$ 2.54	0.33%
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	379446	$ 33,391.23	$ 0.0880	380718	$ 33,503.20	$ 111.97	0.34%
TOU - Off Peak		$ 0.0650	243229	$ 15,809.90	$ 0.0650	244044	$ 15,862.84	$ 52.93	0.33%
TOU - Mid Peak		$ 0.1000	68408	$ 6,840.82	$ 0.1000	68637	$ 6,863.73	$ 22.90	0.33%
TOU - On Peak		$ 0.1170	68408	$ 8,003.76	$ 0.1170	68637	$ 8,030.56	$ 26.80	0.33%
Total Bill on RPP (before Taxes)				**$ 91,629.39**			**$ 89,431.38**	**-$ 2,198.01**	**-2.40%**
HST		13%		$ 11,911.82	13%		$ 11,626.08	-$ 285.74	-2.40%
Total Bill (including HST)				$ 103,541.21			$ 101,057.47	-$ 2,483.75	-2.40%
Ontario Clean Energy Benefit [1]				-$ 10,354.12			-$ 10,105.75	$ 248.37	-2.40%
Total Bill on RPP (including OCEB)				**$ 93,187.09**			**$ 90,951.72**	**-$ 2,235.38**	**-2.40%**
Total Bill on TOU (before Taxes)				**$ 88,847.66**			**$ 86,640.31**	**-$ 2,207.35**	**-2.48%**
HST		13%		$ 11,550.20	13%		$ 11,263.24	-$ 286.96	-2.48%
Total Bill (including HST)				$ 100,397.85			$ 97,903.55	-$ 2,494.30	-2.48%
Ontario Clean Energy Benefit [1]				-$ 10,039.79			-$ 9,790.36	$ 249.43	-2.48%
Total Bill on TOU (including OCEB)				**$ 90,358.06**			**$ 88,113.19**	**-$ 2,244.87**	**-2.48%**

	Current	Proposed
Loss Factor (%)	4.5400%	4.8900%

Appendix K – Cost Allocation Sheet O1 (Updated)

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**General Service Less Than 50 kW**	**General Service 50 to 4,999 kW**	**Street Lighting**	**Sentinel Lighting**	**Unmetered Scattered Load**
crev	Distribution Revenue at Existing Rates	$14,811,517	$8,271,064	$2,430,352	$3,397,715	$656,794	$28,957	$26,635
mi	Miscellaneous Revenue (mi)	$2,600,000	$1,663,491	$367,302	$428,425	$130,715	$5,859	$4,207
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$17,411,517	**$9,934,555**	**$2,797,654**	**$3,826,141**	**$787,509**	**$34,816**	**$30,841**
	Factor required to recover deficiency (1 + D)	1.0965						
	Distribution Revenue at Status Quo Rates	$16,241,350	$9,069,513	$2,664,966	$3,725,715	$720,198	$31,753	$29,206
	Miscellaneous Revenue (mi)	$2,600,000	$1,663,491	$367,302	$428,425	$130,715	$5,859	$4,207
	Total Revenue at Status Quo Rates	$18,841,350	**$10,733,004**	**$3,032,268**	**$4,154,140**	**$850,913**	**$37,612**	**$33,413**
	Expenses							
di	Distribution Costs (di)	$4,583,364	$2,682,229	$605,512	$951,427	$320,427	$13,835	$9,934
cu	Customer Related Costs (cu)	$1,828,353	$1,404,024	$301,165	$91,904	$28,176	$1,802	$1,282
ad	General and Administration (ad)	$3,541,229	$2,248,476	$500,381	$584,969	$192,583	$8,619	$6,201
dep	Depreciation and Amortization (dep)	$3,331,174	$1,994,224	$489,973	$634,586	$197,666	$8,501	$6,222
INPUT	PILs (INPUT)	$249,265	$145,862	$34,808	$54,380	$13,216	$563	$436
INT	Interest	$2,056,787	$1,203,568	$287,212	$448,715	$109,049	$4,642	$3,601
	Total Expenses	$15,590,172	**$9,678,383**	**$2,219,051**	**$2,765,981**	**$861,117**	**$37,963**	**$27,677**
	Direct Allocation	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$3,251,178	$1,902,488	$453,998	$709,287	$172,375	$7,338	$5,692
	Revenue Requirement (includes NI)	$18,841,350	$11,580,871	$2,673,048	$3,475,269	$1,033,492	$45,301	$33,369
		Revenue Requirement Input equals Output						

Appendix K – Cost Allocation Sheet O1 (Updated) - Continued

	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$135,576,347	$79,542,660	$18,806,888	$28,728,243	$7,907,563	$339,312	$251,681
gp	General Plant - Gross	$4,906,448	$2,875,680	$681,078	$1,057,476	$271,744	$11,597	$8,874
accum dep	Accumulated Depreciation	($51,060,743)	($29,991,002)	($7,090,018)	($10,560,441)	($3,183,874)	($137,627)	($97,780)
co	Capital Contribution	($8,155,285)	($4,871,005)	($1,051,154)	($1,500,234)	($682,815)	($29,678)	($20,399)
	Total Net Plant	$81,266,767	$47,556,332	$11,346,793	$17,725,044	$4,312,618	$183,604	$142,376
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$67,087,680	$32,481,106	$9,745,412	$23,999,522	$754,147	$24,241	$83,252
	OM&A Expenses	$9,952,946	$6,334,729	$1,407,058	$1,628,300	$541,186	$24,256	$17,417
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$77,040,626*	*$38,815,835*	*$11,152,470*	*$25,627,822*	*$1,295,332*	*$48,497*	*$100,669*
	Working Capital	$9,244,875	$4,657,900	$1,338,296	$3,075,339	$155,440	$5,820	$12,080
	Total Rate Base	$90,511,642	$52,214,232	$12,685,090	$20,800,382	$4,468,058	$189,424	$154,456
		Rate Base Input equals Output						
	Equity Component of Rate Base	$36,204,657	$20,885,693	$5,074,036	$8,320,153	$1,787,223	$75,769	$61,782
	Net Income on Allocated Assets	$3,251,178	$1,054,621	$813,218	$1,388,158	($10,204)	($351)	$5,736
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$3,251,178	$1,054,621	$813,218	$1,388,158	($10,204)	($351)	$5,736
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	92.68%	113.44%	119.53%	82.33%	83.03%	100.13%
	EXISTING REVENUE MINUS ALLOCATED CC	($1,429,833)	($1,646,316)	$124,606	$350,872	($245,982)	($10,485)	($2,528)
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED	$0	($847,867)	$359,220	$678,871	($182,579)	($7,689)	$43
	RETURN ON EQUITY COMPONENT OF RATE	8.98%	5.05%	16.03%	16.68%	-0.57%	-0.46%	9.28%

Appendix L– Revenue Requirement Work Form (Updated)

	Initial Application	(2)	Adjustments	Interrogatory Responses	(6)	Adjustments	Per Board Decision
Rate Base							
Gross Fixed Assets (average)	$134,901,466			$ 134,901,466		($2,573,955)	$132,327,511
Accumulated Depreciation (average)	($52,587,960)	(5)		($52,587,960)		$1,527,219	($51,060,741)
Allowance for Working Capital:							
Controllable Expenses	$10,928,870			$ 10,928,870		($975,924)	$9,952,946
Cost of Power	$63,539,559		$3,548,121	$ 67,087,680			$67,087,680
Working Capital Rate (%)	13.00%	(9)		13.00%	(9)		12.00%
Utility Income							
Operating Revenues:							
Distribution Revenue at Current Rates	$14,769,498		$33,070	$14,802,568		$8,949	$14,811,517
Distribution Revenue at Proposed Rates	$17,944,453		($165,386)	$17,779,067		($1,537,718)	$16,241,349
Other Revenue:							
Specific Service Charges	$195,190		$0	$195,190		$0	$195,190
Late Payment Charges	$196,000		$0	$196,000		$0	$196,000
Other Distribution Revenue	$1,876,774		$0	$1,876,774		$332,036	$2,208,810
Other Income and Deductions							
Total Revenue Offsets	$2,267,964	(7)	$0	$2,267,964		$332,036	$2,600,000
Operating Expenses:							
OM+A Expenses	$10,928,870			$ 10,928,870		($975,924)	$9,952,946
Depreciation/Amortization	$3,302,877	(10)	$20,791	$ 3,323,668		$7,505	$3,331,173
Property taxes							
Other expenses							
Taxes/PILs							
Taxable Income:							
Adjustments required to arrive at taxable income	($2,418,659)	(3)		($2,418,659)			($2,389,535)
Utility Income Taxes and Rates:							
Income taxes (not grossed up)	$213,384			$204,122			$193,335
Income taxes (grossed up)	$276,280			$263,796			$249,265
Federal tax (%)	22.77%			22.62%			22.44%
Provincial tax (%)							
Income Tax Credits							
Capitalization/Cost of Capital							
Capital Structure:							
Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%
Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%
Common Equity Capitalization Ratio (%	40.0%			40.0%			40.0%
Prefered Shares Capitalization Ratio (%)							
	100.0%			100.0%			100.0%
Cost of Capital							
Long-term debt Cost Rate (%)	4.41%			4.12%			3.91%
Short-term debt Cost Rate (%)	2.08%			2.07%			2.07%
Common Equity Cost Rate (%)	9.12%			8.98%			8.98%
Prefered Shares Cost Rate (%)							

Appendix L – Revenue Requirement Work Form (Updated) – Continued

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$134,901,466	$ -	$134,901,466	($2,573,955)	$132,327,511
2	Accumulated Depreciation (average)	(3)	($52,587,960)	$ -	($52,587,960)	$1,527,219	($51,060,741)
3	Net Fixed Assets (average)	(3)	$82,313,506	$ -	$82,313,506	($1,046,736)	$81,266,770
4	Allowance for Working Capital	(1)	$9,680,896	$461,256	$10,142,152	($897,276)	$9,244,875
5	**Total Rate Base**		$91,994,402	$461,256	$92,455,658	($1,944,012)	$90,511,645

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$10,928,870	$ -	$10,928,870	($975,924)	$9,952,946
7	Cost of Power		$63,539,559	$3,548,121	$67,087,680	$ -	$67,087,680
8	Working Capital Base		$74,468,429	$3,548,121	$78,016,550	($975,924)	$77,040,626
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	-1.00%	12.00%
10	Working Capital Allowance		$9,680,896	$461,256	$10,142,152	($897,276)	$9,244,875

Appendix L – Revenue Requirement Work Form (Updated) – Continued

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$17,944,453	($165,386)	$17,779,067	($1,537,718)	$16,241,349
2	Other Revenue	(1)	$2,267,964	$ -	$2,267,964	$332,036	$2,600,000
3	Total Operating Revenues		$20,212,417	($165,386)	$20,047,031	($1,205,682)	$18,841,349
	Operating Expenses:						
4	OM+A Expenses		$10,928,870	$ -	$10,928,870	($975,924)	$9,952,946
5	Depreciation/Amortization		$3,302,877	$20,791	$3,323,668	$24,588	$3,348,256
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$14,231,747	$20,791	$14,252,538	($951,336)	$13,301,202
10	Deemed Interest Expense		$2,348,433	($138,743)	$2,209,690	($152,904)	$2,056,787
11	Total Expenses (lines 9 to 10)		$16,580,180	($117,952)	$16,462,228	($1,104,240)	$15,357,989
12	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS		$ -	$ -	$ -	($17,082)	($17,082)
13	**Utility income before income taxes**		$3,632,237	($47,434)	$3,584,803	($84,360)	$3,500,442
14	Income taxes (grossed-up)		$276,280	($12,484)	$263,796	($14,531)	$249,265
15	**Utility net income**		$3,355,957	($34,950)	$3,321,007	($69,830)	$3,251,177

Notes

Other Revenues / Revenue Offsets

	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$195,190	$ -	$195,190	$ -	$195,190
	Late Payment Charges	$196,000	$ -	$196,000	$ -	$196,000
	Other Distribution Revenue	$1,876,774	$ -	$1,876,774	$332,036	$2,208,810
	Other Income and Deductions	$ -		$ -		$ -
	Total Revenue Offsets	$2,267,964	$ -	$2,267,964	$332,036	$2,600,000

Appendix L – Revenue Requirement Work Form (Updated) – Continued

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$3,355,956	$3,321,007	$3,251,178
2	Adjustments required to arrive at taxable utility income	($2,418,659)	($2,418,659)	($2,389,535)
3	Taxable income	$937,297	$902,348	$861,643
	Calculation of Utility income Taxes			
4	Income taxes	$213,384	$204,122	$193,335
6	Total taxes	$213,384	$204,122	$193,335
7	Gross-up of Income Taxes	$62,896	$59,674	$55,930
8	Grossed-up Income Taxes	$276,280	$263,796	$249,265
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$276,280	$263,796	$249,265
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	22.77%	22.62%	22.44%
12	Provincial tax (%)	0.00%	0.00%	0.00%
13	Total tax rate (%)	22.77%	22.62%	22.44%

Appendix L – Revenue Requirement Work Form (Updated) – Continued
Capitalization/ Cost of Capital

Particulars	Capitalization Ratio		Cost Rate	Return
	Initial Application			
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$51,516,865	4.41%	$2,271,894
Short-term Debt	4.00%	$3,679,776	2.08%	$76,539
Total Debt	60.00%	$55,196,641	4.25%	$2,348,433
Equity				
Common Equity	40.00%	$36,797,761	9.12%	$3,355,956
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$36,797,761	9.12%	$3,355,956
Total	100.00%	$91,994,402	6.20%	$5,704,389
	Interrogatory Responses			
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$51,775,168	4.12%	$2,133,137
Short-term Debt	4.00%	$3,698,226	2.07%	$76,553
Total Debt	60.00%	$55,473,395	3.98%	$2,209,690
Equity				
Common Equity	40.00%	$36,982,263	8.98%	$3,321,007
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$36,982,263	8.98%	$3,321,007
Total	100.00%	$92,455,658	5.98%	$5,530,697
	Per Board Decision			
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$50,686,521	3.91%	$1,981,843
Short-term Debt	4.00%	$3,620,466	2.07%	$74,944
Total Debt	60.00%	$54,306,987	3.79%	$2,056,787
Equity				
Common Equity	40.00%	$36,204,658	8.98%	$3,251,178
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$36,204,658	8.98%	$3,251,178
Total	100.00%	$90,511,645	5.86%	$5,307,965

Appendix L – Revenue Requirement Work Form (Updated) – Continued
Revenue Deficiency/Sufficiency:

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$3,174,948		$2,976,499		$1,429,834
2	Distribution Revenue	$14,769,498	$14,769,505	$14,802,568	$14,802,568	$14,811,517	$14,811,515
3	Other Operating Revenue Offsets - net	$2,267,964	$2,267,964	$2,267,964	$2,267,964	$2,600,000	$2,600,000
4	**Total Revenue**	$17,037,462	$20,212,417	$17,070,532	$20,047,031	$17,411,517	$18,841,349
5	Operating Expenses	$14,231,747	$14,231,747	$14,252,538	$14,252,538	$13,301,202	$13,301,202
6	Deemed Interest Expense	$2,348,433	$2,348,433	$2,209,690	$2,209,690	$2,056,787	$2,056,787
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ - **(2)**	$ -	$ - **(2)**	$ -	($17,082) **(2)**	($17,082)
8	**Total Cost and Expenses**	$16,580,180	$16,580,180	$16,462,228	$16,462,228	$15,340,907	$15,340,907
9	**Utility Income Before Income Taxes**	$457,282	$3,632,237	$608,304	$3,584,803	$2,070,610	$3,500,442
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,418,659)	($2,418,659)	($2,418,659)	($2,418,659)	($2,389,535)	($2,389,535)
11	**Taxable Income**	($1,961,377)	$1,213,578	($1,810,355)	$1,166,144	($318,925)	$1,110,907
12	Income Tax Rate	22.77%	22.77%	22.62%	22.62%	22.44%	22.44%
13	**Income Tax on Taxable Income**	($446,515)	$276,276	($409,524)	$263,796	($71,560)	$249,265
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$903,797	$3,355,957	$1,017,829	$3,321,007	$2,142,171	$3,251,177
16	**Utility Rate Base**	$91,994,402	$91,994,402	$92,455,658	$92,455,658	$90,511,645	$90,511,645
17	Deemed Equity Portion of Rate Base	$36,797,761	$36,797,761	$36,982,263	$36,982,263	$36,204,658	$36,204,658
18	Income/(Equity Portion of Rate Base)	2.46%	9.12%	2.75%	8.98%	5.92%	8.98%
19	Target Return - Equity on Rate Base	9.12%	9.12%	8.98%	8.98%	8.98%	8.98%
20	Deficiency/Sufficiency in Return on Equity	-6.66%	0.00%	-6.23%	0.00%	-3.06%	0.00%
21	Indicated Rate of Return	3.54%	6.20%	3.49%	5.98%	4.64%	5.86%
22	Requested Rate of Return on Rate Base	6.20%	6.20%	5.98%	5.98%	5.86%	5.86%
23	Deficiency/Sufficiency in Rate of Return	-2.67%	0.00%	-2.49%	0.00%	-1.23%	0.00%
24	Target Return on Equity	$3,355,956	$3,355,956	$3,321,007	$3,321,007	$3,251,178	$3,251,178
25	Revenue Deficiency/(Sufficiency)	$2,452,159	$1	$2,303,179	($0)	$1,109,008	($1)
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,174,948 **(1)**		$2,976,499 **(1)**		$1,429,834 **(1)**	

Appendix L – Revenue Requirement Work Form (Updated) – Continued

Revenue Requirement:

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision
1	OM&A Expenses	$10,928,870		$10,928,870		$9,952,946
2	Amortization/Depreciation	$3,302,877		$3,323,668		$3,348,256
3	Property Taxes	$ -				
5	Income Taxes (Grossed up)	$276,280		$263,796		$249,265
6	Other Expenses	$ -				
7	Return					
	Deemed Interest Expense	$2,348,433		$2,209,690		$2,056,787
	Return on Deemed Equity	$3,355,956		$3,321,007		$3,251,178
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ -		$ -		($17,082)
8	**Service Revenue Requirement (before Revenues)**	$20,212,416		$20,047,031		$18,841,350
9	Revenue Offsets	$2,267,964		$2,267,964		$2,600,000
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$17,944,452		$17,779,067		$16,241,350
11	Distribution revenue	$17,944,453		$17,779,067		$16,241,349
12	Other revenue	$2,267,964		$2,267,964		$2,600,000
13	**Total revenue**	$20,212,417		$20,047,031		$18,841,349
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$1	(1)	($0)	(1)	($1)

Appendix M – Throughput Revenue (Updated)

2013 Test Year Distribution Revenue Reconciliation

Customer Class	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected
Residential	$ 3,393,094	$ 5,687,376		$ 9,080,471	$ 9,069,512
GS < 50 kW	$ 671,357	$ 2,012,941	($21,064)	$ 2,663,235	$ 2,664,966
GS >50 kW	$ 526,680	$ 3,283,046	($84,036)	$ 3,725,690	$ 3,725,714
Sentinel Lights	$ 13,087	$ 18,665		$ 31,753	$ 31,753
Street Lighting	$ 302,284	$ 417,918		$ 720,201	$ 720,198
USL	$ 3,076	$ 26,099		$ 29,175	$ 29,206
Total	**$ 4,909,578**	**$ 11,446,046**	**($105,100)**	**$ 16,250,524**	**$ 16,241,349**
				Difference Due to Rate Rounding	
				-$ 9,175	

Appendix N – Revenue Reconciliation (Updated)

Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Co			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	29,271	29,271	29,271	340,561,450		$ 9.66	$ 0.0167		$ 9,080,471	$ 9,069,512		$ 9,069,512	-$ 10,959
GS < 50 kW	Customers	3,401	3,401	3,401	102,179,766		$ 16.45	$ 0.0197		$ 2,684,299	$ 2,664,966	$ 21,064	$ 2,686,030	$ 1,731
GS > 50 to 4,99	Customers	399	399	399		628,286	$ 110.00		$ 5.2254	$ 3,809,726	$ 3,725,714	$ 84,036	$ 3,809,750	$ 24
Streetlighting	Connections	8,904	8,904	8,904		22,680	$ 2.83		$18.4267	$ 720,297	$ 720,198		$ 720,198	-$ 99
Sentinel Lighting	Connections	387	387	387		710	$ 2.82		$26.2894	$ 31,762	$ 31,753		$ 31,753	-$ 9
USL	Customers	21	21	21	872,889		$ 12.20	$ 0.0299		$ 29,174	$ 29,206		$ 29,206	$ 32
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total										$ 16,355,728	$ 16,241,349	$ 105,100	$ 16,346,449	-$ 9,279

Appendix O – Draft Accounting Order

PUC Distribution Inc.
Draft Accounting Order

PUC Distribution Inc. shall establish the following variance account, Account 1508, Other Regulatory Assets, sub-account Productivity Initiatives Variance Account. This account shall be used to record the notional revenue in the amount of $400,000 collected from PUC Distribution Inc.'s customers and related expenditures from July 1, 2013 to April 30, 2017. For added clarity, this Accounting Order is intended to reflect the Board's Decision and Order in EB-2012-0162 dated June xx, 2013, with specific reference to sections 4.1 and 9.1 of the Settlement Agreement. The amounts recorded in Account 1508, Other Regulatory Assets, sub-account Productivity Initiatives Variance Account shall be brought forward for disposition in PUC Distribution's next Cost of Service rates application. The account shall be closed upon PUC Distribution's next cost of service rebasing period. Carrying charges shall not apply to this account.

1. Accounting entry:

Debit A/R
Credit Account 4080, Distribution Service Revenue
To record distribution revenue when billed

Debit Account 4080, Distribution Service Revenue
Credit Account 1508, Other Regulatory Assets – sub-account Productivity Initiatives\\
To record notional revenue for Productivity Initiatives billed to customers

Debit Account 2425, Other Deferred Credits
Credit Account 4080, Distribution Service Revenue
To record reversal of 4080 using contra account

2. OM&A Accounting entry:

Debit Account 5xxx OM&A expense
Credit Account 2205 Accounts Payable
To record expenditures on OM&A for Productivity Initiatives

Debit Account 1508, Other Regulatory Assets – sub-account Productivity Initiatives
Credit Account 5xxx OM&A expense
To record OM&A expenditures for Productivity Initiatives

Debit Account 5xxx OM&A Expense
Credit Account 2425, Other Deferred Credits
To record reversal of OM&A using contra account

3. Capital Accounting entry:

Debit Account 2055 Construction Work in Progress
Credit Account 2205 Accounts Payable
To record expenditures for construction work in progress for Productivity Initiatives

Debit Account 18xx-19xx Capital Asset
Credit Account 2055 Construction Work in Progress
To record construction work in progress placed in service

Debit Account 1508, Other Regulatory Assets – sub-account Productivity Initiatives
Credit Account 4080 Distribution Revenue
To record the revenue requirement impact of capital expenditures for Productivity Initiatives

Debit Account 4080 Distribution Revenue
Credit Account 2425, Other Deferred Credits
To record reversal of the revenue requirement impact of capital expenditures using contra account

Appendix P – LRAM and LRAMVA Calculation

	Residential	General Service <50kW	General Service > 50kW	Total
Pre 2011 and Jan.1, 2012 to April 30, 2012 - LRAM 2005 to 2010 program with persisting losses ($)	111,476	13,579	8,104	133,159
Carrying LRAM ($)	1,324	161	96	1,581
Sub Total	112,800	13,740	8,200	134,740
Volume (2013 Forecast for July, 1 2013 to April 30, 2014)	289,979,604	87,003,529	542,377	
Charge Parameter	kWh	kWh	kW	
Rate Rider for LRAM	**0.0004**	**0.0002**	**0.0151**	
2011 LRAMVA ($)	12,804	12,203	11,734	36,741
Carrying Charges LRAMVA ($)	353	336	323	1,012
Sub Total	13,157	12,539	12,057	37,753
Volume (2013 Forecast for July, 1 2013 to April 30, 2014)	289,979,604	87,003,529	542,377	
Charge Parameter	kWh	kWh	kW	
Rate Rider for LRAMVA	**0.0000**	**0.0001**	**0.0222**	
Total LRAM and LRAMVA				**172,493**

APPENDIX B

TO DECISION AND RATE ORDER

PUC Distribution Inc.
EB-2012-0162

TARIFF OF RATES AND CHARGES

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date July 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0162

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a single family unit, non-commercial. This can be a separately metered living accommodation, town house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	9.66
Rate Rider for Recovery of Stranded Meter Assets - effective until April 30, 2014	$	3.39
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0167
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) - effective until April 30, 2014	$/kWh	0.0004
Rate Rider for Disposition of Deferral/Variance Accounts(2013) - effective until April 30, 2014	$/kWh	(0.0053)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0019
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date July 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0162

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	16.45
Rate Rider for Recovery of Stranded Meter Assets - effective until April 30, 2014	$	9.76
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0197
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism (LRAM) - effective until April 30, 2014	$/kWh	0.0002
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2011 CDM Activities) - effective until April 30, 2014	$/kWh	0.0001
Rate Rider for Disposition of Deferral/Variance Accounts(2013) - effective until April 30, 2014	$/kWh	(0.0049)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0019
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date July 1, 2013

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EB-2012-0162

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly peak demand used for billing purposes over the past 12 months is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	110.00
Rate Rider for Recovery of Stranded Meter Assets - effective until April 30, 2014	$	6.52
Distribution Volumetric Rate	$/kW	5.2254
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) - effective until April 30, 2014	$/kW	0.0151
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2011 CDM Activities) - effective until April 30, 2014	$/kW	0.0222
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2014	$/kW	(1.8699)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.7511
Retail Transmission Rate – Network Service Rate	$/kW	2.2434
Retail Transmission Rate – Network Service Rate - Interval Metered	$/kW	2.8214

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date July 1, 2013

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EB-2012-0162

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	12.20
Distribution Volumetric Rate	$/kWh	0.0299
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2014	$/kWh	(0.0049)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
TARIFF OF RATES AND CHARGES
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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential or General Service customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.82
Distribution Volumetric Rate	$/kW	26.2894
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2014	$/kW	(4.6117)
Retail Transmission Rate – Network Service Rate	$/kW	1.7006

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

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STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.83
Distribution Volumetric Rate	$/kW	18.4267
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2014	$/kW	(4.5230)
Retail Transmission Rate – Network Service Rate	$/kW	1.6919

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PUC Distribution Inc.
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microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

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

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Customer Administration

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

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge – At Meter After Hours	$	185.00
Disconnect/Reconnect Charge – At Pole During Regular Hours	$	185.00
Disconnect/Reconnect Charge – At Pole After Hours	$	415.00

Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Service call - customer-owned equipment		Time & materials
Service call - after regular hours		Time & materials
Temporary service install & remove - overhead - no transformer		Time & materials
Temporary service install & remove - underground - no transformer		Time & materials
Temporary service install & remove - overhead - with transformer		Time & materials
Removal of overhead lines – during regular hours		Time & materials
Removal of overhead lines – after hours		Time & materials
Roadway escort – after regular hours		Time & materials
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

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TARIFF OF RATES AND CHARGES
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RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0489
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0385