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April 7, 2016

Delivered by RESS, Email and Courier

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

Ms. Walli:

Re: Motion to Review and Vary the Decision in the Welland Hydro 2013 Cost of Service Rate Application (EB-2012-0173) – WITH CONSENT

We are counsel to Welland Hydro-Electric System Corp. ("**Welland Hydro**") in relation to the above noted matter. We have been retained in order to bring a motion to review and vary the Ontario Energy Board's (the "**Board's**") Decision and Order dated March 21, 2013 in Welland Hydro's 2013 Cost of Service Rate Application, EB-2012-0173 (the "**Decision**"). The basis for the motion are (i) a change in circumstances; and (ii) new facts that have arisen.

Prior to filing this letter, Welland Hydro has reached out to each of parties to the EB-2012-0173 settlement approved by the Decision, being Energy Probe, SEC and VECC, and asked them if they would consent to this motion to vary on the basis of the rationale set out below. Each of Energy Probe, SEC and VECC have consented to: (i) Welland Hydro's request to vary the Decision as described below; and (ii) Welland Hydro's request to waive the Rule 40.03 timeframe as described below. Energy Probe, SEC and VECC's consent was conditional: that Welland Hydro will not record any costs associated with a lead-lag study into account 1508 should the Board grant the requested variance. Welland Hydro agreed to this condition.

Welland Hydro is seeking an order varying the Decision to delete the requirement arising under issue 2.2 of the Board approved settlement that states:

> "The Parties have agreed that Welland will prepare a lead-lag study in advance of its next cost of service distribution rate application, and file it for review in that proceeding. The Parties have agreed that Welland will track the costs associated with the lead-lag study in 1508 Sub Account - Other Costs and that those costs will be recoverable by Welland in its next cost of service rate application, subject to their review by the Board at that time."

Welland Hydro is not seeking to vary any other aspect of the settlement, including the agreement that the working capital percentage be set at 12%, which was a 1% decrease from the 13% in the original application.

Change in circumstances

The requirement to file a lead-lag study was part of the settlement agreement that was approved by the Board under a particular policy context. At the time, the Board's policy on working capital allowance permitted a utility to use a default value of 13%, unless the utility prepared a lead-lag study to evidence their actual working capital needs. At the time, it was often the case that a lead-lag study would demonstrate, for a utility on monthly billing, that actual working capital requirements were less than 13%.

However, on June 3, 2015, the Board issued a letter announcing a new default working capital allowance of 7.5%. According to this letter, distributors who do not wish to use the default value can request approval for a distributor-specific working capital allowance supported by the appropriate evidence from a lead-lag study or equivalent analysis.

This change in policy has resulted in a reversal of the implications of the settlement of issue 2.2 as described above. Whereas previously a lead-lag study for a distributor on monthly billing would tend to fall below the default value of 13%, it is more likely than not that a lead-lag study completed for 2017 will result in an actual working capital requirement that is greater than or equal to 7.5%.

New facts have arisen

As part of its 2017 cost of service rate application, Welland Hydro would prefer to use the new default working capital allowance of 7.5%. Specifically, Welland Hydro would prefer not to apply for a distributor-specific working capital allowance and would prefer to forego the cost, effort and expense of preparing a lead-lag study.

A key term of the above noted settlement is that the costs associated with the lead-lag study would be recorded in account 1508 and that those costs will be recoverable by Welland Hydro in its next cost of service rate application, subject to their review by the Board at that time. Given this, Welland Hydro believes its customer's would benefit directly from lower costs in account 1508 should the Board permit the requested variance.

Finally, Welland Hydro asks that the Board waive the typical timeframe to bring a motion under Rule 40.03 (within 20 calendar days of a Board's order or decision). Meeting this timeline would have been impossible given that the change in policy on working capital allowance occurred more than 2 years after the Decision.

The following documents are attached as they are directly relevant to this motion:

(a) the Decision;

(b) the letter dated June 3, 2015 from the Board to All Licensed Electricity Distributors regarding the change in policy related to working capital allowance;

(c) the letter dated July 16, 2015 from the Board updating the Filing Requirements for Electricity Distribution Rate Applications to include, among other things, the new default value of 7.5% for working capital allowance; and

(d) such further documentary evidence as Welland Hydro may submit and the Board allow.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Original signed by John A.D. Vellone

John A.D. Vellone

CC: Wayne Armstrong, Chief Operating Officer & Director of Finance, Welland Hydro
Parties of record in EB-2012-0173

TAB A

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2012-0173

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 Welland Hydro-Electric System Corp. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

BEFORE: Paula Conboy
Presiding Member

Emad Elsayed
Member

DECISION AND ORDER

Welland Hydro-Electric System Corp. ("Welland Hydro") filed an application with the Ontario Energy Board (the "Board") on October 9, 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 Welland Hydro charges for electricity distribution, to be effective May 1, 2013. The Board has assigned the application File Number EB-2012-0173.

On November 12, 2012, the Board issued Procedural Order No. 1 wherein it established intervenor status and cost award eligibility for Energy Probe Research Foundation ("Energy Probe"), School Energy Coalition ("SEC") and the Vulnerable Energy Consumers Coalition ("VECC") and set dates for this proceeding including interrogatories and interrogatory responses. On December 20, 2012 the Board issued Procedural Order No. 2, granting Welland Hydro an extension to the date to file its responses to interrogatories. On January 10, 2013, the Board issued Procedural Order No. 3, which set dates for supplemental interrogatories and responses, and a settlement conference. A date of February 19, 2013 was also set for the filing of any proposed settlement agreement arising from the settlement conference.

The settlement conference took place on February 4 and 5, 2013. Welland Hydro, SEC, VECC and Energy Probe (collectively, the “Parties”) participated in the settlement conference. The Parties reached a complete settlement on all issues in the proceeding.

On February 19, 2013 Welland Hydro filed a proposed Settlement Agreement with the Board. The Settlement Agreement is included as Appendix A to this Decision and Order.

Welland Hydro submitted detailed supporting material, including all relevant calculations showing the impact of the implementation of the proposed Settlement Agreement on Welland Hydro’s revenue requirement, the allocation of the resulting revenue requirement to the classes and the determination of the final rates, including bill impacts and a proposed Tariff of Rates and Charges.

Findings

The Board has reviewed the proposed Settlement Agreement and accepts it as filed. The Board commends the parties on achieving complete settlement of all matters. Welland Hydro’s new rates are to be effective May 1, 2013.

The Board makes the following comments on two areas that are inconsistent with the Board’s policies.

In settling Issue 5.1 (Is the proposed capital structure, rate of return on equity (“ROE”) and short term debt rate appropriate?) the parties have agreed that the Board’s Cost of Capital Parameters for ROE (8.93%) and short term debt (2.08%) for rates effective January 1, 2013 should be used to determine the revenue requirement and associated rates.

The Board notes that the use of the January 1 ROE, deemed Long-Term (“LT”) and Short-Term (“ST”) debt rates to set May 1 rates is a departure from the Board’s cost of capital policy . However, given the recently announced levels of the May 1 ROE, deemed LT and ST debt rates, the Board concludes that the impact of departing from the Board’s policy in this case is not material and results in no harm to ratepayers. Furthermore the settlement was agreed to by all parties and substantially simplifies the process for issuing the Rate Order.

The Board also notes that the settlement of Issue 4.2 (Is the proposed level of depreciation/amortization expense for the test year appropriate?) is a departure from the Board's policy with respect to the accounting for Account 1575 and Account 1576 set out in the July 2012 Accounting Procedures Handbook. The Board concludes that the departure from the Board's policy in this instance results in no harm to ratepayers. Furthermore the settlement was agreed to by all parties and substantially simplifies the process for issuing the Rate Order.

The Board reminds Parties that the individual elements of a settlement agreement do not create a precedent for the Board.

In addition to its findings on the Settlement Agreement, the Board is making provision for the following two matters to be incorporated into Welland Hydro's Tariff of Rates and Charges at this time.

Rural or Remote Electricity Rate Protection Charge

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Rural or Remote Electricity Rate Protection ("RRRP") used by rate regulated distributors to bill their customers shall be $0.0012 per kilowatt hour effective May 1, 2013. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects this RRRP charge.

Wholesale Market Service Rate

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Wholesale Market Service rate ("WMS rate") used by rate regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects this WMS rate.

A Rate Order will be issued after the steps set out below are completed.

THE BOARD ORDERS THAT:

1. Intervenors and Board staff shall file with the Board any comments on the draft Tariff of Rates and Charges set out in Appendix B and forward to Welland Hydro within **7 days** of the date of issuance of this Decision and Order.

2. Welland Hydro shall file with the Board and forward to intervenors responses to any comments on the draft Tariff of Rates and Charges within **7 days** of the date of receipt of Board staff and intervenor comments.

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. Intervenors shall file with the Board and forward to Welland Hydro their respective cost claims within **7 days** from the date of issuance of the final Rate Order.

2. Welland Hydro shall file with the Board and forward to intervenors any objections to the claimed costs within **17 days** from the date of issuance of the final Rate Order.

3. Intervenors shall file with the Board and forward to Welland Hydro any responses to any objections for cost claims within **24 days** of the date of issuance of the final Rate Order.

4. Welland Hydro 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-2012-0173, and be made through the Board's web portal at www.errr.ontarioenergyboard.ca, 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. All other filings not filed via the Board's web portal should be filed in accordance with the Board's *Practice Directions on Cost Awards*.

All communications should be directed to the attention of the Board Secretary and be received no later than 4:45 p.m. on the required date.

DATED at Toronto, March 21, 2013

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

TO DECISION AND ORDER
EB-2012-0173

Welland Hydro-Electric System Corp.
Settlement Agreement

DATED: February 19, 2013

Welland Hydro
ELECTRIC SYSTEM CORP.
POWERING WELLAND'S FUTURE

February 19, 2013

Delivered by Courier and E-file

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

Dear Ms. Walli:

Re: Welland Hydro-Electric System Corp.
2013 Distribution Rates Application
Board File No. EB-2012-0173

In accordance with Procedural Order No. 3, a Settlement Conference was convened in respect of this proceeding on February 4th and February 5th 2013. Welland is pleased to advise the Parties have achieved a complete settlement in this matter. Each of the Parties has reviewed and approved the Agreement, and the Parties respectfully request the Board approve the Settlement Agreement. The Parties acknowledge with thanks the assistance of Mr. Haussmann and Board Staff in this process.

Please find enclosed paper copies (2) and electronic copy (1) of the proposed Settlement Agreement and associated excel spreadsheets.

Yours very truly,

Wayne Armstrong

Wayne Armstrong
Director of Finance
905-732-1381 Ext 234
905-732-0266 Fax
Email: warmstrong@wellandhydro.com

EB-2012-0173

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 Welland Hydro-Electric System Corp. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

WELLAND HYDRO-ELECTRIC SYSTEM CORP. ("WELLAND")

PROPOSED SETTLEMENT AGREEMENT

FILED: FEBRUARY 19, 2013

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EB-2012-0173

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 Welland Hydro-Electric System Corp. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

WELLAND HYDRO-ELECTRIC SYSTEM CORP. ("WELLAND")
PROPOSED SETTLEMENT AGREEMENT
FILED: FEBRUARY 19, 2013

INTRODUCTION:

Welland carries on the business of distributing electricity within the City of Welland as described in its distribution licence.

Welland filed an application with the Ontario Energy Board (the "Board") on August 31, 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 Welland charges for electricity distribution, to be effective May 1, 2013 (the "Application"). The Board assigned the Application File Number EB-2012-0173.

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

In Procedural Order No. 1, issued on November 12, 2012, 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, issued on December 20, 2012, the Board extended the date for filing responses to interrogatories to December 31, 2012.

In Procedural Order No 3, issued on January 10, 2013, the Board set dates for supplementary interrogatories and interrogatory responses; and dates for a Settlement Conference (February 4, 2013, continuing February 5, 2013 if necessary); and, the filing of any Settlement Proposal arising out of the Settlement Conference (February 19, 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 Welland'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. 3, with Mr. Chris Haussmann as facilitator. The Settlement Conference was held on February 4 and 5, 2013.

Welland and the following Intervenors participated in the Settlement Conference:

- Energy Probe;
- SEC; and
- VECC.

Welland and the Intervenors are collectively referred to below as the "Parties".

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 Welland, Energy Probe, SEC and VECC to the Board. It identifies the settled matters and contains such references to the Evidence as are necessary to assist the Board in understanding the Agreement. 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-2012-0173. 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 a proposed schedule of Rates and Charges. If the Board approves the Agreement Welland expects to use the information in Appendix I as the basis for its draft Rate Order following Board approval of this Agreement.

The Parties believe the Agreement represents a balanced proposal that protects the interests of Welland's customers, employees and shareholder and promotes economic efficiency and cost effectiveness. It also provides the resources which will allow Welland 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 have agreed the effective date of the rates resulting from this proposed Agreement is May 1, 2013 (referred to below as the "Effective Date").

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 Welland's 2013 distribution rates.

The following Appendices accompany this Settlement Agreement:

Appendix A – Summary of Significant Changes (Updated)
Appendix B – Continuity Tables
Appendix C – Cost of Power Calculation (Updated)
Appendix D – 2013 Customer Load Forecast (Updated)
Appendix E – 2013 Other Revenue
Appendix F – 2013 PILS (Updated)
Appendix G – 2013 Cost of Capital
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)

UNSETTLED MATTERS:

There are no unsettled matters in this proceeding.

OVERVIEW OF THE SETTLED MATTERS:

This Agreement will allow Welland 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 Welland 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 Welland's distribution licence; and continue to provide the high level of customer service that Welland'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 Welland is not converting to International Financial Reporting Standards ("IFRS") in the 2013 Test Year and will remain on CGAAP until required by the Accounting Standards Board (the "AcSB") to move to IFRS. However, Welland 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. Welland has implemented the regulatory accounting changes for depreciation expense and capitalization policies effective January 1, 2012. As a result of these changes, Welland expects that there will be no material adjustments when Welland ultimately converts to IFRS.

In Welland's initial evidence (Exhibit 6 Table 6.1) the Service Revenue Requirement for the 2013 Test Year was $9,659,680 ($9,663,584 - RRWF) which included a Base Revenue Requirement of $9,158,591 ($9,162,495 – RRWF) and Revenue Offsets of $501,089 with a resulting Revenue Deficiency of $187,802 ($191,706 – RRWF). The difference between the figures found in Exhibit 6 Table 6.1 in the initial evidence and the original Revenue Requirement Work Form is $3,904. In Exhibit 4, Tab 1, Schedule 8, and Page 3, Welland submitted that the RRWF correctly calculated the Grossed Up PILS at $62,416 versus the $58,512 Grossed Up PILS found in Exhibit 6 Table 6.1 for a difference of $3,904. In response to Board Staff IR#41, Welland confirmed that it would use the Grossed Up PILS as per the RRWF methodology in final rate calculations in this proceeding if approved by the Board. Welland used this methodology in calculating Grossed Up PILS in response to changes during interrogatories.

Through the interrogatory and settlement process, Welland 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	COS Application RRWF	Difference Filing vs RRWF	Interogatory Responses	Settlement Submission	Difference Filing vs Settlement
Service Revenue Requirement	A	$9,659,680	$9,663,584	$3,904	$9,700,249	$9,290,039	-$369,641
Revenue Offsets	B	-$501,089	-$501,089	$0	-$520,054	-$575,000	-$73,911
Base Revenue Requirement	C=A+B	$9,158,591	$9,162,495	$3,904	$9,180,195	$8,715,039	-$443,552
Revenue at Existing Rates	D	$8,970,789	$8,970,789	$0	$8,970,789	$9,004,606	$33,817
Revenue Deficiency/(Sufficiency)	E=C-D	$187,802	$191,706	$3,904	$209,406	-$289,567	-$477,369

The revised Service Revenue Requirement for the 2013 Test Year is $9,290,039 which reflects the updated cost of capital parameters (ROE and Deemed Short Term Debt rate) issued by the Board on November 15, 2012 applicable to applications for rebasing effective January 1, 2013. The long term debt rate was agreed to be 3.78%, for the purpose of settlement. Compared to the forecast 2013 revenue at current rates of $9,004,606 the revised Service Revenue Requirement represents a sufficiency of $289,567 which is a $477,369 change from the revenue deficiency of $187,802 set out in Table 6.1 in Welland's COS Application filing.

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

1. GENERAL

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

Status: **Complete Settlement**

Supporting Parties: Welland, 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 Welland's economic and business planning assumptions for 2013 appropriate?

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

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

For the purposes of settlement, the Parties accept Welland'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: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 3, Schedule 8

For the purposes of settlement, the Parties accept Welland'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: Welland, Energy Probe, SEC, VECC

Evidence: Application: Addendum, Appendix A, Page 2 of 4

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

2. RATE BASE

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

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2
Board Staff Supplemental IR #49 (2012 Capital/Depreciation Expense)
Board Staff Supplemental IR #51B (2013 Remove Early Retirement Amounts)
Board Staff IR#4 (2013 Capital - Double Bucket Truck - Revised)

For the purposes of settlement, the Parties have agreed that Welland's amended forecast Rate Base of $31,435,867 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 were accepted as proposed in Welland's interrogatory responses. The 2013 revised capital expenditures were agreed to during the settlement process. 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:

- With respect to Cost of Power, the Parties have agreed for the purposes of settlement to accept The Load Forecast in Welland's Initial Application <u>except</u> for the following:
    - The manual CDM adjustment for 2013 has been reduced from the gross level to the net level. The adjustment also reflects a full year of 2012 programs persisting into 2013 along with the half year rule being applied to 2013 programs.
    - The load attributed to GS>50kW class has been adjusted to reflect a change in the kW/kWh factor used to convert kWh to kW from 0.2778% to 0.2798%;
    - CDM Activity variable was adjusted to reflect the final 2011 CDM results;
    - RPP rates were updated to reflect the change in charges effective November 1, 2012;
    - The Smart Meter Entity charge was removed from the Working Capital calculation;

- o The Retail Transmission Network & Connection charges were updated to reflect the change in the Ontario uniform electricity transmission rates effective January 1, 2013;
- o The Rural or Remote Electricity Rate Protection (RRRP) costs were updated to reflect the revised charges effective January 1, 2013 as per EB-2012-0453.

The Cost of Power was therefore increased from $43,137,251 to $43,394,903 as a result of these changes. Please see Appendix C for the detailed Cost of Power calculation.

- The Parties have agreed that the 2013 OM&A for the Test Year, including property taxes, should be $6,370,000 (CGAAP), a decrease of $266,967 from $6,636,967 in the original Application. OM&A expenses are discussed in further detail under item 4.1.

- The Parties have agreed 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 $5,971,788, a decrease of $498,860 from $6,470,648 in the original Application. Working Capital Rate is discussed in further detail under item 2.2.

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 Welland's proposed Overall Rate Base under CGAAP are set out in Settlement Table #2: Rate Base, below.

Settlement Table #2: Rate Base

Rate Base

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Settlement Agreement
Gross Fixed Assets (average)	$53,874,400	($33,245)	$53,841,155	$41,597	$53,882,752
Accumulated Depreciation (average)	($28,460,717)	$42,710	($28,418,007)	($666)	($28,418,673)
Net Fixed Assets (average)	$25,413,683	$9,465	$25,423,148	$40,931	$25,464,079
Allowance for Working Capital	$6,470,648	$4,604	$6,475,252	($503,464)	$5,971,788
Total Rate Base	$31,884,331	$14,069	$31,898,400	($462,533)	$31,435,867

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

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 1 Schedule 1

For the purposes of settlement, the Parties agree to the following Working Capital Allowance calculated based on 12% of the OM&A expenses of $6,370,000 (CGAAP including property tax), and Cost of Power of $43,394,903. The reduction from 13% to 12% is intended to give effect, on an interim basis, to the reductions in required working capital that result from Welland's implementation of monthly billing.

The Parties have agreed that Welland will prepare a lead-lag study in advance of its next cost of service distribution rate application, and file it for review in that proceeding. The Parties have agreed that Welland will track the costs associated with the lead-lag study in 1508 Sub Account -Other Costs and that those costs will be recoverable by Welland in its next cost of service rate application, subject to their review by the Board at that time.

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

Settlement Table #3: Allowance for Working Capital

Allowance for Working Capital

Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Settlement Agreement
Controllable Expenses	$6,636,967	$35,415	$6,672,382	($302,382)	$6,370,000
Cost of Power	$43,137,252	$ -	$43,137,252	$257,651	$43,394,903
Working Capital Base	$49,774,219	$35,415	$49,809,634	($44,731)	$49,764,903
Working Capital Rate %	13.00%	0.00%	13.00%	-1.00%	12.00%
Working Capital Allowance	$6,470,648	$4,604	$6,475,252	($503,464)	$5,971,788

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

Status:	**Complete Settlement**
Supporting Parties:	Welland, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 2, Tab 3, Schedules 1-3 Board Staff IR #4

For the purposes of settlement, the Parties have accepted net capital expenditures of $1,976,365 amended from Welland's original Application of $2,001,200 reflecting Welland's response to Board Staff IR #4. The resulting continuity schedules are shown in Appendix B.

2.4 Is the capitalization policy and allocation procedure appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Welland, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 2, Tab 3, Schedule 5

For the purposes of settlement, the Parties have accepted Welland's capitalization policy as it was set out in Exhibit 2, Tab 3, Schedule 5 of the original Application. The Parties have agreed that Welland should use deferral account 1576 to record 2012 adjustments to PP&E as a result of Welland adopting extended asset lives and overhead capitalization policies effective January 1, 2012. This is detailed under Section 4.2.

3. LOAD FORECAST AND OPERATING REVENUE

3.1 Is the load forecast methodology including weather normalization appropriate?

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 3, Tab 2, Schedule 1
Board Staff IR#20-26 Supplemental IR#52-54
EP IR#12-14
VECC IR#14-21 Supplemental IR#39-44

For the purposes of settlement, the Parties accept Welland'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 the CDM manual adjustment from gross to net based on 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 2013 programs.

- The load attributed to GS>50kW class has been adjusted to 396,002 kW reflecting a change in the kW/kWh factor used to convert kWh to kW from 0.2778% to 0.2798%;

- CDM Activity variable was adjusted to reflect the final 2011 CDM results:

This results in a billed consumption forecast of 421,635,735 kWh and 570,669 kW in the 2013 Test Year. The accepted CDM adjustment for 2012 and 2013 CDM programs is 3,165,795 kWh and 4,220 kW 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: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 3, Tab 2, Schedule 1, Table 3-22

For the purposes of settlement, the Parties accept Welland's customers/connections forecast (both kWh and kW) for the 2013 Test Year. With respect to the load forecast, through the settlement process Welland modified the movement of the CDM manual adjustment from gross to net consumption to exclude the free ridership. The changes made to the consumption for all classes reflect the CDM manual adjustment from gross to net consumption, and also reflect application of the half year rule for 2013 programs. Settlement Table #4: Load Forecast, details the above changes. Appendix D reflects the revised load forecast.

Settlement Table #4: Load Forecast

	Initial Application Filing	Settlement Adjustments	Settlement Agreement
Residential			
Customers	20,432	0	20,432
kWh	160,995,683	1,569,935	162,565,618
GS<50 kW			
Customers	1,696	0	1,696
kWh	54,236,152	548,382	54,784,534
GS 50 to 4,999 kW			
Customers	169	0	169
kWh	140,269,569	1,260,825	141,530,394
kW	389,693	6,309	396,002
Large User			
Customers	1	0	1
kWh	59,134,727	403,974	59,538,701
kW	167,672	1,146	168,818
Street Lights			
Connections	6,750	0	6,750
kWh	1,264,642	8,639	1,273,281
kW	3,552	0	3,552
Sentinel Lights			
Connections	574	0	574
kWh	826,332	5,645	831,977
kW	2,297	0	2,297
Unmetered Loads			
Connections	225	0	225
kWh	1,103,690	7,540	1,111,230
Totals			
Customer/Connections	29,847	0	29,847
kWh	417,830,795	3,804,940	421,635,735
kW from applicable classes	563,215	7,454	570,669

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

Status:	**Complete Settlement**
Supporting Parties:	Welland, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 3 Tab 2 Schedule 1

For the purposes of settlement, the Parties agree that the CDM adjustment should be changed from gross to net, and the half year rule should be applied to the 2013 programs. The CDM adjustment for 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. The result is a reduction from 6,533,052 kWh to 3,165,795 kWh. This reflects both the move from gross to net and the 2013 half year rule. 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

	Billed Load Forecast before CDM Adjustment (kWh)	Billed Load Forecast after CDM Adjustment (kWh)	CDM Adjustment (kWh)
Residential	163,780,236	162,565,618	1,214,618
GS<50 KW	55,208,803	54,784,534	424,269
GS>50 KW	142,577,942	141,530,394	1,047,548
Large Use	59,993,492	59,538,701	454,791
Street Lighting	1,283,007	1,273,281	9,726
Sentinel Lighting	838,332	831,977	6,355
USL	1,119,718	1,111,230	8,488
	424,801,530	421,635,735	3,165,795

	Billed Load Forecast before CDM Adjustment (kW)	Billed Load Forecast after CDM Adjustment (kW)	CDM Adjustment (kW)
GS>50 KW	398,933	396,002	2,931
Large Use	170,107	168,818	1,289
Street Lighting	3,552	3,552	0
Sentinel Lighting	2,297	2,297	0
	574,889	570,669	4,220

For the purposes of settlement, the Parties agree the 2013 LRAMVA amount of 6,224,832 kWh and 8,452 kW has been calculated using the OPA's 2011-2014 CDM targets assigned to Welland, which reflects the actual 2011 CDM results and the persistence of 2011 into 2013. The LRAMVA amount differs from the CDM adjustment of 3,165,795 kWh and 4,220 kW, as the persistent savings from 2011 must be included in the calculation in order to capture the correct amount of targets assigned to Welland for 2013. Therefore, the 2013 LRAMVA includes the 2011 persistent savings of 2,003,772 kWh as provided by the OPA's 2011 Final Annual Report, 2012 persistent savings of 2,110,530 kWh and the full year 2013 forecasted savings of 2,110,530 kWh. Settlement Table #6: LRAMVA Calculation, below provides details of the 2013 kWh and kW savings which will be used in the calculation of the LRAMVA account.

Settlement Table #6: LRAMVA Calculation

2011 to 2014 CDM Targets per Year					
20,600,000					
	2011	2012	2013	2014	Total
2011 Programs	9.8%	9.8%	9.7%	9.2%	38.5%
2012 Programs		10.2%	10.2%	10.2%	30.7%
2013 Programs			10.2%	10.2%	20.5%
2014 Programs				10.2%	10.2%
	9.8%	20.0%	30.2%	39.9%	100.0%
2011-2014 CDM kWh Targets per Year					
2011 Programs	2,018,776	2,017,177	2,003,772	1,897,094	7,936,820
2012 Programs		2,110,530	2,110,530	2,110,530	6,331,590
2013 Programs			2,110,530	2,110,530	4,221,060
2014 Programs				2,110,530	2,110,530
	2,018,776	4,127,707	6,224,832	8,228,684	20,600,000

The Parties agree, for the purposes of settlement, the LRAMVA amount is to be allocated to the customer classes based on the percentages outlined in proportion of the class kWh to the total. Settlement Table #7: LRAMVA Allocation per Customer Class, below provides details of this allocation.

Settlement Table #7: LRAMVA Allocation per Customer Class

	LRAMVA kWh	Allocation per Class	Total LRAMVA kWh Allocated per Class	Total LRAMVA kW Allocated per Class
Residential		38.4%	2,388,275	0
GS<50 kW		13.4%	834,230	0
GS>50 kW		33.1%	2,059,770	5,825
Large Use		14.4%	894,246	2,536
Street Lighting		0.3%	19,124	53
Sentinel Lighting		0.2%	12,496	39
USL		0.3%	16,690	0
	6,224,831		6,224,831	8,453

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

Status:	**Complete Settlement**
Supporting Parties:	Welland, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 8 Appendix A

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:	Welland, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 3, Tab 1 & Tab 3 Board Staff IR#44 VECC IR#45 Board Staff Supplemental IR#51b Energy Probe Supplemental IR#30c

For the purposes of settlement, the Parties agreed upon a forecast of $575,000 in Other Distribution Revenue, an increase of $73,911 from $501,089 as set out in the original application. Appendix E – 2013 Other Revenue provides additional detail.

The revised other revenue values reflect the following significant changes:

- The Parties agreed that it was appropriate to:
    - Eliminate the Loss from Early Retirement Assets - Account 4390 (CGAAP)
    - Increase the Interest Income Revenue

4. OPERATING COSTS

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

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 4 Tab 1, Exhibit 6, Tab 1
Board Staff IR#30/35
Energy Probe IR#19
VECC IR#29

For the purposes of settlement, the Parties agree the 2013 OM&A for the Test Year should be $6,370,000 (CGAAP), a decrease of $266,967 from the $6,636,967 original Application Filing and a decrease of $302,382 from the revised $6,672,382 submitted through the interrogatory process. The Parties relied on Welland's view that it can safely and reliably operate the distribution system based on the total OM&A budget proposed. Welland has provided, in Settlement Table #8: OM&A Expense Budget, below a revised OM&A budget based on this 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.

Settlement Table #8: OM&A Expense Budget

	Initial Application	Supplemental IRR Response	Settlement Adjustments	Settlement Agreement
Operations	$1,508,194	$0	-$115,937	$1,392,257
Maintenance	$1,756,582	$0	-$135,030	$1,621,552
Billing & Collecting	$1,423,275	$0	-$16,000	$1,407,275
Community Relations	$134,249	$0	$0	$134,249
Administrative & General	$1,814,667	$35,415	-$35,415	$1,814,667
Total	$6,636,967	$35,415	-$302,382	$6,370,000

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

Status:	**Complete Settlement**
Supporting Parties:	Welland, Energy Probe, SEC, VECC
Evidence:	Application: Exhibit 2 Tab 2 Application: Exhibit 2, Tab 3, Schedule 5 Board Staff IR#4 Board Staff Supplemental IR#49

For the purposes of settlement, the Parties accept the useful lives proposed by Welland in Settlement Table #9: Depreciation Useful Lives, below and the depreciation expense reported in the continuity schedules in Appendix B. The Parties have agreed on depreciation/amortization expenses of $1,228,565 less $143,383 related to Account 1576, for a total of $1,085,182 for the 2013 Test Year.

As cited in Welland's Application, the Applicant adopted revised depreciation periods which were detailed in Exhibit 2, Tab 3, Schedule 5, and Appendix C. The analysis in Exhibit 2, Tab 3, and Schedule 5 provides comparisons to depreciation rates adopted by Welland with the typical useful lives as indicated in the Kinectrics Study dated July 8, 2010 which was commissioned by the OEB. Welland 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, Welland Hydro is required to record the effect of the changes to PP&E in 2012 in account 1576.

It was agreed by all Parties that Welland 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. Based on the Board's July 2012 APH-FAQs related to depreciation and capitalization changes and guidance provided in Q&A #2, Appendix A and B, Welland removed the Weighted Average Cost of Capital (WACC) adjustment of $35,324 included as part of account 1575 in the original application. As part of the settlement agreement, it was agreed by all Parties that in Welland'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 $33,093 as detailed in Appendix B below. The calculation of this amount for account 1576 is now based on the same principles as account 1575 in

Welland's original application. 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 Welland's next Cost of Service Application in 2017.

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 through written submissions.

Settlement Table #9: Depreciation Useful Lives

Welland Hydro Electric System Corp.
Components List and useful lives

			Kinectrics Study Useful Life			
CGAAP Account	**IFRS**	**MIN**	**TYP**	**MAX**	**Utilization Factors**	**Welland Hydro**
	Overhead system:					
1830	Poles	35	45	75	MC, EN	50
1835	OH Conductors and Switches	50	60	75	MC, EL, EN	50
1850	Transformers (includes OH and UG)	30	40	60	EL, EN	40
1820	MS Substations					
14 different accounts	1820 Transformers - already a component	30	45	60	EL, EN	45
14 different accounts	1820 Switchgear - already a component	30	40	60	EL, EN, OP	35
14 different accounts	1820 Switches - already a component	30	50	60	MC, EL, EN	30
14 different accounts	1820 Buildings - already a component	50		75		60
	Underground system:					
1855	Secondary Cables (includes both OH and UG)	25-35	35-40	40-60	MC, EL, EN	40
1845	Primary Non-TR	20	25	30	MC, EL, EN	25
1845	Primary TR	25	30	35	MC, EL, EN	30
1840	Switchgear	20	30	45	EN	30
1840	Ducts & foundations	30	50	80	EN	50
1980	Scada					
	1980 software	15	20	30	NPF	10
	1980 devices	15	20	30	NPF	20
	1980 computers	15	20	30	NPF	5
	Minor Assets					
1915	-Office Equipment	5		15		10
1930	-Vehicles					
	1930 trucks	5		15		15
	1930 trailers	5		20		20
	1930 vans/cars	5		10		10
1908	-Administrative Buildings	50		75		60
1808	-Station Buildings	50		75		60
1920	-Computer Hardware	3		5		4
1925	-Computer Software	2		5		5
	Equipment					
1940	Major Tools	5		10		10
1935	Store	5		10		10
1945	Measurement & testing	5		10		10
1955	Communication					
	1955 Towers	60		70		60
	1955 Wireless (Radio)	2		10		5
1960	Generator					25
N/A	Residential Meters - stranded	25		35		25
N/A	Industrial Meters	25		35		15
N/A	Wholesale Meters	15		30		15
1815	Wholesale Metering TS Station+C21					35
1860	Smart meters	5		20		15

4.3 Are the 2013 compensation costs and employee levels appropriate?

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 4 Tab 1
Board Staff IR#28/35
VECC IR#24
Energy Probe IR#19

For the purpose of settlement, the Parties accept that Welland's forecasted 2013 Test Year compensation costs and employee levels may be affected by the overall reduction in 2013 Test Year OM&A discussed above in Section 4.1. As a result, Welland's revised OM&A budget anticipates a reduction in the forecasted 2013 FTE's from 44 (including part time) to 43, which is an increase of 1 over current levels. The addition represents the hiring of an apprentice lineperson required as a result of impending retirements. All Parties accept that the compensation costs and employee levels in the revised OM&A budget are appropriate.

4.4 Is the test year forecast of property taxes appropriate?

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: N/A

Welland has included property taxes payable in the 2013 Test Year as part of OM&A expenses which have been agreed to by all Parties.

4.5 Is the test year forecast of PILs appropriate?

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 4 Tab 1 Schedule 8 Exhibit 4 Appendix E
Energy Probe 22
Energy Probe 30b

For the purpose of settlement, the parties accept Welland's 2013 Test Year PILs forecast as set out in Appendix F to this Settlement Agreement. Please see Appendix F – 2013 PILs (Updated), for additional details. The changes are a small increase in the tax credits for apprentices, and a small increase in CCA, plus changes resulting from other changes throughout this Agreement.

5. 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: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 5 Tab 1
Energy Probe IR#24

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

This Settlement Agreement has been prepared using the Board's updated Cost of Capital Parameters for ROE (8.93%) and short term debt (2.08%) for cost of service applications for rates effective January 1, 2013, issued on November 15, 2012. For the purposes of settlement, the Parties have agreed these rates will be applied for the May 1, 2013 implementation date. These rates will be incorporated into the Draft Rate Order to be prepared following the issuance of the Board's Decision on the Settlement Agreement. (Long-term debt is addressed separately in Section 5.2.)

Settlement Table #10: Deemed Capital Structure for 2013, below provides details of the above-noted parameters. Please also refer to Appendix G – 2013 Cost of Capital.

Settlement Table #10: Deemed Capital Structure for 2013

Per Settlement Agreement				
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$17,604,086	3.78%	$665,434
Short-term Debt	4.00%	$1,257,435	2.08%	$26,155
Total Debt	60.00%	$18,861,520	3.67%	$691,589
Equity				
Common Equity	40.00%	$12,574,347	8.93%	$1,122,889
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$12,574,347	8.93%	$1,122,889
Total	100.00%	$31,435,867	5.77%	$1,814,478

5.2 Is the proposed long term debt rate appropriate?

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 5 Tab 1
Energy Probe IR#24

For the purposes of settlement, the Parties accept Welland's long term debt rate of 3.78%. The calculation of the long term debt rate is set out in Appendix G to this Agreement. The Long Term Debt Rate of 3.78% is based on the weighted average of the Note Payable to the Shareholder of $13,499,953 at the deemed rate of 4.03% and the Note Payable to TD Securities at the actual rate of 2.87%.

6. STRANDED METERS

6.1 Is the proposal related to Stranded Meters appropriate?

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 3, Schedule 6
Energy Probe IR#10/11
VECC IR#11

For the purposes of settlement, the Parties accept the stranded meter net book value of $480,240 as presented in Settlement Table #11: Stranded Meter Customer Class Rate Rider, below. The Parties accept the proposal for recovery of the amount through a rate rider of $0.45 per metered Residential customer per month, and a rate rider of $0.48 metered General Service < 50 kW customer per month. Welland will recover costs over a four year period, commencing May 1, 2013.

Settlement Table #11: Stranded Meter Customer Class Rate Rider

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -		$ -
2007					$ -		$ -
2008					$ -		$ -
2009					$ -		$ -
2010	Actual	$ 2,194,968	$ 1,555,042		$ 639,926	$ 2,128	$ 637,798
2011	Actual	$ 2,194,968	$ 1,635,495		$ 559,473	$ 3,564	$ 555,909
2012	Actual	$ 2,194,968	$ 1,711,164		$ 483,804	$ 3,564	$ 480,240

Note: For 2010 and 2011 Stranded Meters were recorded in 1860 and transferred to 1555 Effective January 1, 2012
Depreciation Expense will continue in Account 1555 in 2012 and totals $75,669
No Carrying Charges have been included in Account 1555 for Stranded Meters in 2012
Welland is requesting disposition of the $480,240 Related to 1555 Smart Meters in this Rate Application
As per response to Board Staff Interogatory 2b in EB-2011-0415 these charges will be split by class as follows:

		# Customers	# Months	Rate Rider/Mth
Residential	$441,084	20,432	48	$0.45
GS<50	$39,156	1,696	48	$0.48
Total	$480,240	22,128		

7. COST ALLOCATION

7.1 Is Welland's cost allocation appropriate

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 7
Board Staff IR#42
VECC IR#33/34
Energy Probe IR#26
SEC IR#17/18

The Parties have agreed for the purposes of settlement, the 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

Class	Revenue Requirement - 2013 Cost Allocation Model - Line 40 from O1 in CA	2013 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2013 Cost Allocation Model - Line 19 from O1 in CA	Total Revenue	Revenue Cost Ratio	Check Revenue Cost Ratios from 2013 Cost Allocation Model - Line 75 from O1 in CA	Proposed Revenue to Cost Ratio
Residential	5,998,831	6,145,771	379,785	6,525,556	108.8%	108.8%	106.5%
GS < 50 kW	1,118,010	1,005,810	68,092	1,073,902	96.1%	96.1%	96.1%
GS >50 to 4999 kW	1,806,382	1,077,580	102,339	1,179,919	65.3%	65.3%	80.0%
Large Use	101,544	177,030	0	177,030	174.3%	174.3%	106.5%
Sentinel Lights	39,282	30,777	4,315	35,091	89.3%	89.3%	89.3%
Street Lighting	187,006	233,118	17,901	251,019	134.2%	134.2%	106.5%
Unmetered and Scattered	38,984	44,954	2,568	47,522	121.9%	121.9%	106.5%
TOTAL	9,290,040	8,715,039	575,000	9,290,039			

Class	2013 Proposed Service Revenue Requirement	2013 Proposed Miscellaneous Revenue per Cost Allocation Model	2013 Proposed Base Revenue Requirement	Board Target Low	Board Target High
Residential	6,387,201	379,785	6,007,416	85%	115%
GS < 50 kW	1,073,903	68,092	1,005,811	80%	120%
GS >50 to 4999 kW	1,445,106	102,339	1,342,766	80%	120%
Large Use	108,118	0	108,118	85%	115%
Sentinel Lights	35,090	4,315	30,776	80%	120%
Street Lighting	199,113	17,901	181,212	70%	120%
Unmetered and Scattered	41,508	2,568	38,941	80%	120%
TOTAL	**9,290,039**	**575,000**	**8,715,039**		

The revenue to cost ratios above include an adjustment to the Direct Costs allocated to the Large Use class which was agreed to by all Parties as part of this Agreement. Please see Appendix K – Cost Allocation Sheet O1 for additional information. The adjustment was based on increasing directly allocated administrative costs to 1.6% of total general and administrative expense of $1,936,384 included in the application cost allocation model minus the amount already included for general and administrative expense of $2,672 and $3,860.

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

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 7

For the purposes of settlement, the Parties have accepted 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 Welland's revenue to cost ratios remain subject to further Board policy changes of general application over this period.

8. RATE DESIGN

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

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 8 Tab 1
Energy Probe IR#27/28
SEC IR#19

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.

Settlement Table #13: Fixed Charge Analysis

Customer Class	Current Volumetric Split	Current Fixed Charge Split	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)
Residential	36.10%	63.90%	100.00%	15.66	16.55	11.87
GS < 50 kW	43.70%	56.30%	100.00%	27.83	28.75	15.03
GS >50 to 4999 kW	38.16%	61.84%	100.00%	409.43	339.49	49.78
Large Use	14.80%	85.20%	100.00%	7,676.01	12,986.14	0
Sentinel Lights	42.82%	57.18%	100.00%	2.56	2.64	5.65
Street Lighting	15.59%	84.41%	100.00%	1.89	2.51	5.11
Unmetered and Scattered	21.29%	78.71%	100.00%	11.35	13.54	11.18
TOTAL	41.58%	58.42%	100.00%			

The parties agree the monthly service charge for all classes, except for the GS>50 to 4,999 kW class, would be the lesser of the current monthly service charge or the monthly service charge using the current fixed/variable split. However, the monthly service charges for the GS>50 to 4,999 kW class would be set at $267.94. 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

Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Proposed Variable Rate
Residential	6,007,416	68.93%	15.66	$0.0133
GS < 50 kW	1,005,811	11.54%	27.83	$0.0082
GS >50 to 4999 kW	1,342,766	15.41%	267.94	$2.3435
Large Use	108,118	1.24%	7,676.01	$0.7948
Sentinel Lights	30,776	0.35%	2.56	$5.7365
Street Lighting	181,212	2.08%	1.89	$7.9541
Unmetered and Scattered	38,941	0.45%	11.35	$0.0075
TOTAL	**8,715,039**	**100.00%**		

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

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Appendix 8 Appendix B
Revised RTSR Workform

For the purposes of settlement the Parties have agreed the following Retail Transmission Service Rates ("RTSRs"), based on the updated 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 and RTSR Connection Rates, below.

Settlement Table #15: RTSR Network and RTSR Connection Rates

Rate Class	Unit	Proposed RTSR Network		Proposed RTSR Connection	
Residential	kWh	$	0.0083	$	0.0055
General Service Less Than 50 kW	kWh	$	0.0073	$	0.0048
General Service 50 to 4,999 kW	kW	$	2.5129	$	1.6428
General Service 50 to 4,999 kW – Interval Metered	kW	$	2.4926	$	1.9679
Large Use	kW	$	1.8264	$	2.1853
Unmetered Scattered Load	kWh	$	0.0073	$	0.0048
Sentinel Lighting	kW	$	2.3404	$	1.5302
Street Lighting	kW	$	2.3353	$	1.5269

8.3 Are the proposed loss factors appropriate?

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 8 Tab 1 Schedule 5

For the purposes of settlement, the Parties accept the Distribution Loss Factor of 1.0485 calculated using a 5 year average for the period 2007 to 2011 inclusive as shown in Settlement Table #17: Loss Factors, below.

When the Supply Facility Loss Factor of 1.0045 is applied to the Distribution Loss Factor the resulting Total Loss Factor for secondary metered customers is 1.0532 as shown in Settlement Table #17: Loss Factors, below:

Settlement Table #17: 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)	493,927,030	487,062,910	419,617,213	443,594,623	452,100,623	459,260,480
A(2)	"Wholesale" kWh delivered to distributor (lower value)	491,714,316	484,880,946	417,737,395	441,607,390	450,075,284	457,203,066
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	84,878,749	103,613,834	52,428,320	59,291,407	60,593,427	72,161,147
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	406,835,567	381,267,112	365,309,074	382,315,983	389,481,857	385,041,919
D	"Retail" kWh delivered by distributor	470,352,000	467,550,816	401,259,942	424,292,841	429,952,199	438,681,560
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	84,038,365	102,587,954	51,909,228	58,704,363	59,993,492	71,446,680
F	Net "Retail" kWh delivered by distributor = **D - E**	386,313,635	364,962,862	349,350,714	365,588,478	369,958,707	367,234,879
G	Loss Factor in Distributor's system = **C / F**	1.053122463	1.044673724	1.045680057	1.045755012	1.05277116	1.048489511
	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**	1.057861514	1.049374756	1.050385617	1.050460909	1.057508631	1.053207713

9. DEFERRAL AND VARIANCE ACCOUNTS

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

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 9
Board Staff IR#45-48
Board Staff Supplemental IR#49
Energy Probe Supplemental IR#42
VECC Supplemental IR#50

For the purposes of settlement, the Parties have agreed 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 Welland has appropriately calculated the Stranded Meter Net Book Value as $480,240. The parties have further agreed to recovery of the Stranded Meter Net Book Value through Rate Riders in the amount of $0.45 per metered Residential customer, per month and $0.48 per General Service < 50 kW customer, per month over a four year period, as discussed in Section 6.1, above.

- The Parties have agreed for the purposes of settlement, the balances of the deferral and variance accounts for disposal will include the interest accrued until April 30, 2013.

- The Parties have agreed that Welland should use account 1576 (1575 original application) to record the adjustment to PP&E accounts as a result of Welland adopting revised extended lives and overhead capitalization policies (which are MIFRS-compliant) effective January 1, 2012. The balance agreed for disposition of $573,531 ($586,779 original application) is the revised forecast provided in response to Board Staff supplemental interrogatory #49. The balance of $573,531 will be returned to customers over a four year period commencing May 1, 2013 as a reduction to depreciation expense, in the same manner as Account 1575. The yearly reduction to depreciation expense of $143,383 is detailed in Appendix B below. Although not included in the amount recorded in deferral account 1576, the Parties have agreed to include a WACC adjustment of $33,093 (5.77% of $573,531) in the determination of rates. This deferral account is not subject to interest. As set out in Section 4.2, the proposed treatment of Account 1576 is severable from the rest of the terms of this Agreement.

- The Parties have agreed that Welland will withdraw its request for a deferral account relating to the change in accounting methodology for Post Retirement Benefits under IFRS versus CGAAP. Welland agrees to file an application to create such an account, and for recovery/disposition of these amounts when converting to IFRS.

- The Parties have agreed that a deferral account is required for Welland to recover costs associated with performing a Lead/Lag Study. This study is to be completed in time for Welland's next Cost of Service Application. Welland believes that Account 1508 Other Regulatory Assets can be used to capture these costs for disposition in Welland's next cost of service application. This account will be subject to interest.

- The Parties have agreed to the disposition of all other Group 1 and Group 2 accounts "on a final basis" as proposed in Welland's original Application.

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 #18: Group 1 & Group 2 Deferral and Variance Accounts

Account Description	Account Number	Principal Balance as at Dec 31, 2011	Interest Amounts as at Dec 31, 2012	Dec 31, 2011 Total	Projected Interest from Jan 1, 2012 to Apr 30, 2013 on Dec 31, 2011 Balances	Total Claim
Group 1 Accounts						
RSVA Wholesale Service Charge	1580	-$415,650	-$4,300	-$419,950	-$8,147	-$428,097
RSVA Retail Transmission Network Charge	1584	$249,250	$729	$249,979	$4,885	$254,864
RSVA Retail Transmission Connection Charge	1586	$135,550	$33	$135,583	$2,657	$138,240
RSVA Power - Excluding Global Adjustment	1588	$306,835	$511	$307,346	$6,013	$313,359
Regulatory Balances 2009	1590	$0	-$6,730	-$6,730	$0	-$6,730
Regulatory Balances 2010	1590	-$32,927	-$519	-$33,446	-$645	-$34,091
Total Group 1 Excluding Global Adjustment		$243,058	-$10,276	$232,782	$4,763	$237,545
RSVA Global Adjustment	1589	$112,037	$3,711	$115,748	$2,196	$117,944
Total Group 1 Including Global Adjustment		$355,095	-$6,565	$348,530	$6,959	$355,489

Account Description	Account Number	Principal Balance as at Dec 31, 2011	Interest Amounts as at Dec 31, 2012	Dec 31, 2011 Total	Projected Interest from Jan 1, 2012 to Apr 30, 2013 on Dec 31, 2011 Balances	Total Claim
Group 2 Accounts						
Other Regulatory -Deferred IFRS Tansition Costs	1508	$44,673	$613	$45,286	$876	$46,162
PILS and Tax Variance for Years 2006 and Subsequent Years HST Input Tax Credits	1592	-$46,566	-$1,346	-$47,912	-$913	-$48,825
Total Group 2		-$1,893	-$733	-$2,626	-$37	-$2,663

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

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 9

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 have agreed to a disposition period of 24 months. The Parties' acceptance of a 24 month recovery on DVA balances, except for Stranded Meter recoveries, will allow Welland to maintain an appropriate cash flow position through recovery of outstanding amounts from its customers. As noted in section 6.1 above, the Parties have agreed, for the purposes of settlement that the Stranded Meter recovery period will be over 4 years, commencing May 1, 2013.

All Parties agree that the disposition period of 24 months will be the period of May 1, 2013 to April 30, 2015. 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 Balances

		Amounts from Sheet 2	Allocator	Residential	General Service <50 kW	General Service 50 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lights	Street Lights
RSVA - Wholesale Market Service Charge	1580	(428,097)	kWh	(165,057)	(55,624)	(143,699)	(60,451)	(1,128)	(845)	(1,293)
RSVA - Retail Transmission Network Charge	1584	254,864	kWh	98,265	33,115	85,550	35,989	672	503	770
RSVA - Retail Transmission Connection Charge	1586	138,240	kWh	53,300	17,962	46,403	19,521	364	273	417
RSVA - Power (excluding Global Adjustment)	1588	313,359	kWh	120,819	40,716	105,185	44,249	826	618	946
RSVA - Power - Sub-account - Global Adjustment	1588	117,944	Non-RPP kWh	11,180	4,241	68,724	33,046	28	18	707
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	(6,730)	kWh	(2,595)	(874)	(2,259)	(950)	(18)	(13)	(20)
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	(34,091)	kWh	(13,144)	(4,430)	(11,443)	(4,814)	(90)	(67)	(103)
Total of Group 1 Accounts (excluding 1588 sub-account)		**237,545**		**91,588**	**30,865**	**79,737**	**33,543**	**626**	**469**	**717**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	46,162	kWh	17,798	5,998	15,495	6,518	122	91	139
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(48,825)	kWh	(18,825)	(6,344)	(16,389)	(6,895)	(129)	(96)	(147)
Total of Group 2 Accounts		**(2,663)**		**(1,027)**	**(346)**	**(894)**	**(376)**	**(7)**	**(5)**	**(8)**
Total Balance Allocated to each class (excluding 1588 sub-account)		**234,882**		**90,561**	**30,519**	**78,843**	**33,167**	**619**	**463**	**709**
Total Balance in Account 1588 - sub account		**117,944**		**11,180**	**4,241**	**68,724**	**33,046**	**28**	**18**	**707**
Total Balance Allocated to each class (including 1588 sub-account)		**352,826**		**101,741**	**34,760**	**147,567**	**66,213**	**647**	**482**	**1,416**

Settlement Table #20: Deferral and Variance Account Disposition Rate Riders below reflects the rate riders for disposition over a period of 24 months.

Settlement Table #20: Deferral and Variance Account Disposition Rate Riders

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	162,565,618	$ 90,561	**0.0003**	$/kWh
General Service <50 kW	kWh	54,784,534	$ 30,519	**0.0003**	$/kWh
General Service 50 to 4,999 kW	**kW**	396,002	$ 78,843	**0.0995**	**$/kW**
Large Use	**kW**	168,818	$ 33,167	**0.0982**	**$/kW**
Unmetered Scattered Load	kWh	1,111,230	$ 619	**0.0003**	$/kWh
Sentinel Lights	**kW**	2,297	$ 463	**0.1009**	**$/kW**
Street Lights	**kW**	3,552	$ 709	**0.0998**	**$/kW**
		-	$ -	-	
Total			**$ 234,882**		

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-account - Global Adjustment**	**Rate Rider for RSVA - Power - Sub-account - Global Adjustment**	
Residential	kWh	20,143,345	$ 11,180	**0.0003**	$/kWh
General Service <50 kW	kWh	7,640,105	$ 4,241	**0.0003**	$/kWh
General Service 50 to 4,999 kW	**kW**	346,450	$ 68,724	**0.0992**	**$/kW**
Large Use	**kW**	168,818	$ 33,046	**0.0979**	**$/kW**
Unmetered Scattered Load	kWh	50,133	$ 28	**0.0003**	$/kWh
Sentinel Lights	**kW**	91	$ 18	**0.1005**	**$/kW**
Street Lights	**kW**	3,552	$ 707	**0.0995**	**$/kW**
		-	$ -	-	
Total			**$ 117,944**		

10. GREEN ENERGY ACT PLAN

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

Status: **Complete Settlement**

Supporting Parties: Welland, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 3, Schedule 4
Board Staff IR #5-14
Energy Probe IR #9
VECC IR #9

For the purposes of settlement, the Parties accept Welland's basic Green Energy Act Plan as set out in Welland's original Application with the exception of an adjustment to the timing of a capital expansion related to a FIT solar project. This expansion was originally forecast for 2013 at a capital cost of $84,000 (MIFRS) and included in 2013 Test Year Capital. The project developers have advised Welland that this project has been delayed to 2014. As a result, Welland has adjusted the 2013 Test Year capital detail by project to remove the solar capital expansion and increase the amount related to the Southworth plant replacement by an equivalent amount of $84,000.

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. Welland will use the appropriate deferral accounts relating to the solar expansion in 2014 and will seek recovery through a prudence review of costs at a future date.

Appendix A – Summary of Significant Changes

	Original Application (A)	Per Settlement Agreement (B)	Difference (B)-(A)
Rate Base			
Gross Fixed Assets (average)	$53,874,400	$53,882,752	$8,352
Accumulated Depreciation (average)	($28,460,717)	($28,418,673)	$42,044
Allowance for Working Capital:			
Controllable Expenses	$6,636,967	$6,370,000	($266,967)
Cost of Power	$43,137,252	$43,394,903	$257,651
Working Capital Rate (%)	13.00%	12.00%	-1.00%
Utility Income			
Operating Revenues:			
Distribution Revenue at Current Rates	$8,970,789	$9,004,606	$33,817
Distribution Revenue at Proposed Rates	$9,158,591	$8,715,039	($443,552)
Other Revenue:			
Specific Service Charges	$150,385	$155,775	$5,390
Late Payment Charges	$70,849	$71,971	$1,122
Other Distribution Revenue	$236,908	$236,941	$33
Other Income and Deductions	$42,947	$110,313	$67,366
Total Revenue Offsets	$501,089	$575,000	$73,911
Operating Expenses:			
OM+A Expenses	$6,636,967	$6,370,000	($266,967)
Depreciation/Amortization	$1,081,619	$1,085,182	$3,563
Property taxes			
Taxes/PILs			
Taxable Income:			
Adjustments required to arrive at taxable	($807,525)	($789,326)	$18,199
Utility Income Taxes and Rates:			
Income taxes (not grossed up)	$50,245	$43,045	($7,200)
Income taxes (grossed up)	$62,416	$53,472	($8,944)
Federal tax (%)	15.00%	15.00%	0.00%
Provincial tax (%)	4.50%	4.50%	0.00%
Income Tax Credits	($19,100)	($22,000)	($2,900)
Capitalization/Cost of Capital			
Capital Structure:			
Long-term debt Capitalization Ratio (%)	56.0%	56.0%	0.00%
Short-term debt Capitalization Ratio (%)	4.0%	4.0%	0.00%
Common Equity Capitalization Ratio (%)	40.0%	40.0%	0.00%
Prefered Shares Capitalization Ratio (%)			0.00%
	100.0%	100.0%	
Cost of Capital			
Long-term debt Cost Rate (%)	4.08%	3.78%	-0.30%
Short-term debt Cost Rate (%)	2.06%	2.08%	0.02%
Common Equity Cost Rate (%)	9.12%	8.93%	-0.19%
Prefered Shares Cost Rate (%)			
Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)	($35,324)	($33,093)	$2,231

Appendix A (Continued): Summary of Significant Changes

Exhibit	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital %	Working Capital Allowance	Amortization Before 1575/1576 Adjustment	PP&E 1575/1576 Adjustment	WCCA 1575/1576	PILS	OM&A	Service Revenue Requiremnt	Revenue Offsets	Base Revenue Requirement	Gross Revenue Def/(Suf)	Reference	Driver
Original Submission	$1,917,906	6.02%	$31,884,331	$49,774,219	13.00%	$6,470,648	$1,228,313	-$146,695	-$35,324	$58,513	$6,636,967	$9,659,680	$501,089	$9,158,591	$187,802		
Increase Microfit Service Charge													$33	-$33	-$33	IRR Rnd #1	Board Staff #44
CGAAP vs MIFRS Remove Early Retirement Assets 2013 - Gross	-$2,001	6.02%	-$33,245		13.00%							-$2,001		-$2,001	-$2,001	IRR Rnd #2 IRR Rnd #2	EP #30B BS # 49/51
CGAAP vs MIFRS Remove Early Retirement Assets 2013 - Acc Dep	$2,571	6.02%	$42,710		13.00%							$2,571		$2,571	$2,571	IRR Rnd #2 IRR Rnd #2	EP #30B BS # 49/51
CGAAP vs MIFRS Remove Early Retirement Assets 2013 - Other Revenue Offset													$18,932	-$18,932	-$18,932	IRR Rnd #2 IRR Rnd #2	EP #30B BS # 49/51
CGAAP vs MIFRS Adjustment 5645 Post Employment Benefit Exp	$277	6.02%	$4,604	$35,415	13.00%	$4,604					$35,415	$35,692		$35,692	$35,692	IRR Rnd #2 IRR Rnd #2	EP #30B BS # 49/51
CGAAP vs MIFRS Adjustment 1575 Removed									$35,324			$35,324		$35,324	$35,324	IRR Rnd #2 IRR Rnd #2	EP #30B BS # 49/51
Change to Regualted Returns for Jan 1/ 2013 Rebasers	-$32,919	5.91%										-$32,919		-$32,919	-$32,919	IRR Rnd#1	EP#24
Resulting Change Gross PILS										$1,902		$1,902		$1,902	$1,902		
Revised Totals Interrogatories	$1,885,834	5.91%	$31,898,400	$49,809,634	13.00%	$6,475,252	$1,228,313	-$146,695	$0	$60,415	$6,672,382	$9,700,249	$520,054	$9,180,195	$209,406		
Change 2012 Capital to Revised Forecast-Gross	$3,192	5.91%	$54,015									$3,192		$3,192	$3,192	IRR Rnd#2	BS#49
Change 2013 Capital to Revised Forecast	-$734	5.91%	-$12,418									-$734		-$734	-$734	IRR Rnd#1	BS#4
Change 2012 Depreciation to Revised	-$64	5.91%	-$1,080				1080					$1,016		$1,016	$1,016	IRR Rnd#2	BS#49
Change 2013 Capital to Revised Forecast	$24	5.91%	$414				-828					-$804		-$804	-$804	IRR Rnd#1	BS#4
PP&E 1576 Adjustment to Forecast								$3,312				$3,312		$3,312	$3,312	Settlement Conference	
WACC Adjustment 1576									-$33,093			-$33,093		-$33,093	-$33,093	Settlement Conference	
Adj to Load Forecast-Base Revenue															-$33,817	Settlement Conference	
Adj to Load Forecast-Rate Return	$1,980	5.91%	$33,495	$257,651	13.00%	$33,495						$1,980		$1,980	$1,980	Settlement Conference	
Adjustment to OM&A	-$2,323	5.91%	-$39,310	-$302,382	13.00%	-$39,310					-$302,382	-$304,705		-$304,705	-$304,705	Settlement Conference	
Adjustment to Working Capital %	-$29,421	5.91%	-$497,649		12.00%	-$497,649						-$29,421		-$29,421	-$29,421	Settlement Conference	
Adjustment to Long Term Debt %	-$44,010											-$44,010		-$44,010	-$44,010	Settlement Conference	
Adjustment to Other Revenue													$54,946	-$54,946	-$54,946	Settlement Conference	
Resulting Change Gross PILS										-$6,943		-$6,943		-$6,943	-$6,943	Settlement Conference	
Revised Totals Settlement	$1,814,478	5.77%	$31,435,867	$49,764,903	12.00%	$5,971,788	$1,228,565	-$143,383	-$33,093	$53,472	$6,370,000	$9,290,040	$575,000	$8,715,039	-$289,567		

Appendix B – Continuity Tables& Transitional PP&E Amounts

Appendix 2-B

Fixed Asset Continuity Schedule-MIFRS

Year 2012

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)					$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)					$ -				$ -	$ -
N/A	1805	Land		$ 158,686			$ 158,686	$ -			$ -	$ 158,686
	1806	Land Rights		$ 70,296			$ 70,296	-$ 58,991	-$ 640		-$ 59,631	$ 10,665
47	1808	Buildings		$ 96,567			$ 96,567	-$ 58,755	-$ 1,236		-$ 59,991	$ 36,576
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 467,359			$ 467,359	-$ 22,990	-$ 14,857		-$ 37,847	$ 429,512
47	1820	Distribution Station Equipment <50 kV		$ 4,041,746			$ 4,041,746	-$ 2,471,216	-$ 71,683		-$ 2,542,899	$ 1,498,847
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 6,451,507	$ 569,015		$ 7,020,522	-$ 1,050,515	-$ 122,890		-$ 1,173,405	$ 5,847,117
47	1835	Overhead Conductors & Devices		$ 12,589,209	$ 305,500		$ 12,894,709	-$ 8,186,375	-$ 120,862		-$ 8,307,237	$ 4,587,472
47	1840	Underground Conduit		$ 826,654	$ 79,000		$ 905,654	-$ 113,723	-$ 16,054		-$ 129,777	$ 775,877
47	1845	Underground Conductors & Devices		$ 11,458,895	$ 171,000		$ 11,629,895	-$ 7,235,953	-$ 205,480		-$ 7,441,433	$ 4,188,462
47	1850	Line Transformers		$ 6,467,733	$ 358,500		$ 6,826,233	-$ 3,302,221	-$ 111,060		-$ 3,413,281	$ 3,412,952
47	1855	Services (Overhead & Underground)		$ 647,473	$ 34,000		$ 681,473	-$ 105,934	-$ 15,428		-$ 121,362	$ 560,111
47	1860	Meters		$ 224,145			$ 224,145	-$ 84,165	-$ 8,475		-$ 92,640	$ 131,505
47	1860	Meters (Smart Meters)		$ 2,755,384	$ 12,000		$ 2,767,384	-$ 386,894	-$ 184,092		-$ 570,986	$ 2,196,398
	1870	Other Installations-Customer Premises		$ 8,010			$ 8,010	-$ 2,882	-$ 2,564		-$ 5,446	$ 2,564
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ 2,169,785	$ 275,000		$ 2,444,785	-$ 956,310	-$ 61,319		-$ 1,017,629	$ 1,427,156
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 90,319	$ 17,500		$ 107,819	-$ 49,604	-$ 9,250		-$ 58,854	$ 48,965
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 287,608	$ 35,000		$ 322,608	-$ 223,707	-$ 39,126		-$ 262,833	$ 59,775
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
	1925	Computer Software		$ 1,010,405	$ 90,000		$ 1,100,405	-$ 441,749	-$ 138,101		-$ 579,850	$ 520,555
10	1930	Transportation Equipment		$ 1,391,450			$ 1,391,450	-$ 1,125,125	-$ 29,819		-$ 1,154,944	$ 236,506
8	1935	Stores Equipment		$ 30,023			$ 30,023	-$ 27,093	-$ 759		-$ 27,852	$ 2,171
8	1940	Tools, Shop & Garage Equipment		$ 114,950	$ 13,000		$ 127,950	-$ 79,839	-$ 8,121		-$ 87,960	$ 39,990
8	1945	Measurement & Testing Equipment		$ 20,391			$ 20,391	-$ 15,746	-$ 1,299		-$ 17,045	$ 3,346
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 279,005			$ 279,005	-$ 119,132	-$ 24,143		-$ 143,275	$ 135,730
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ 315,235			$ 315,235	-$ 70,424	-$ 11,128		-$ 81,552	$ 233,683
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,134,745	$ 27,500		$ 1,162,245	-$ 859,358	-$ 49,204		-$ 908,562	$ 253,683
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 2,033,600	-$ 100,000		-$ 2,133,600	$ 362,475	$ 63,000		$ 425,475	-$ 1,708,125
	etc.			$ -			$ -	$ -			$ -	$ -
				$ -			$ -	$ -			$ -	$ -
		Total		$ 51,073,980	$ 1,887,015	$ -	$ 52,960,995	-$ 26,686,226	-$ 1,184,590	$ -	-$ 27,870,816	$ 25,090,179

8		Stores Equipment

Less: *Fully Allocated Depreciation*

Stranded Meters	-$ 75,669
Net Depreciation	-$ 1,260,259

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

Fixed Asset Continuity Schedule-MIFRS

Year 2013

				Cost				Accumulated Depreciation				
Class	OEB	Description	Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account					$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)					$ -				$ -	$ -
N/A	1805	Land		$ 158,686			$ 158,686	$ -			$ -	$ 158,686
	1806	Land Rights		$ 70,296			$ 70,296	-$ 59,631	-$ 640		-$ 60,271	$ 10,025
47	1808	Buildings		$ 96,567			$ 96,567	-$ 59,991	-$ 1,236		-$ 61,227	$ 35,340
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ 467,359			$ 467,359	-$ 37,847	-$ 14,857		-$ 52,704	$ 414,655
47	1820	Distribution Station Equipment <50 kV		$ 4,041,746			$ 4,041,746	-$ 2,542,899	-$ 71,683		-$ 2,614,582	$ 1,427,164
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 7,020,522	$ 625,000		$ 7,645,522	-$ 1,173,405	-$ 134,831		-$ 1,308,236	$ 6,337,286
47	1835	Overhead Conductors & Devices		$ 12,894,709	$ 133,600		$ 13,028,309	-$ 8,307,237	-$ 125,253		-$ 8,432,490	$ 4,595,819
47	1840	Underground Conduit		$ 905,654	$ 116,200		$ 1,021,854	-$ 129,777	-$ 18,006		-$ 147,783	$ 874,071
47	1845	Underground Conductors & Devices		$ 11,629,895	$ 192,100		$ 11,821,995	-$ 7,441,433	-$ 211,532		-$ 7,652,965	$ 4,169,030
47	1850	Line Transformers		$ 6,826,233	$ 317,300		$ 7,143,533	-$ 3,413,281	-$ 119,507		-$ 3,532,788	$ 3,610,745
47	1855	Services (Overhead & Underground)		$ 681,473	$ 35,000		$ 716,473	-$ 121,362	-$ 16,290		-$ 137,652	$ 578,821
47	1860	Meters		$ 224,145			$ 224,145	-$ 92,640	-$ 8,475		-$ 101,115	$ 123,030
47	1860	Meters (Smart Meters)		$ 2,767,384	$ 50,000		$ 2,817,384	-$ 570,986	-$ 186,159		-$ 757,145	$ 2,060,239
	1870	Other Installations-Customer Premises		$ 8,010			$ 8,010	-$ 5,446	-$ 2,564		-$ 8,010	$ -
N/A	1905	Land		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures		$ 2,444,785	$ 20,000		$ 2,464,785	-$ 1,017,629	-$ 65,006		-$ 1,082,635	$ 1,382,150
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 107,819			$ 107,819	-$ 58,854	-$ 9,591		-$ 68,445	$ 39,374
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware		$ 322,608	$ 46,000		$ 368,608	-$ 262,833	-$ 27,988		-$ 290,821	$ 77,787
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
	1925	Computer Software		$ 1,100,405	$ 58,500		$ 1,158,905	-$ 579,850	-$ 144,712		-$ 724,562	$ 434,343
10	1930	Transportation Equipment		$ 1,391,450	$ 325,165	-$ 132,851	$ 1,583,764	-$ 1,154,944	-$ 40,657	$ 132,851	-$ 1,062,750	$ 521,014
8	1935	Stores Equipment		$ 30,023			$ 30,023	-$ 27,852	-$ 759		-$ 28,611	$ 1,412
8	1940	Tools, Shop & Garage Equipment		$ 127,950	$ 5,000		$ 132,950	-$ 87,960	-$ 8,298		-$ 96,258	$ 36,692
8	1945	Measurement & Testing Equipment		$ 20,391			$ 20,391	-$ 17,045	-$ 1,168		-$ 18,213	$ 2,178
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ 279,005			$ 279,005	-$ 143,275	-$ 21,373		-$ 164,648	$ 114,357
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ 315,235			$ 315,235	-$ 81,552	-$ 11,128		-$ 92,680	$ 222,555
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ 1,162,245	$ 52,500		$ 1,214,745	-$ 908,562	-$ 50,852		-$ 959,414	$ 255,331
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 2,133,600			-$ 2,133,600	$ 425,475	$ 64,000		$ 489,475	-$ 1,644,125
	etc.			$ -			$ -	$ -			$ -	$ -
				$ -			$ -	$ -			$ -	$ -
		Total		$ 52,960,995	$ 1,976,365	-$ 132,851	$ 54,804,509	-$ 27,870,816	-$ 1,228,565	$ 132,851	-$ 28,966,530	$ 25,837,979

Less: *Fully Allocated Depreciation*	
Account 1576	$ 143,383
Net Depreciation	-$ 1,085,182

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

Appendix 2-EB
CGAAP Transitional PP&E Amounts
2012 Adopters of Extended Lives & Overhead Capitalization

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used In Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$	$	$	$	$
PP&E Values under CGAAP								
Opening net PP&E - Note 1				24,387,754				
Additions				2,168,085				
Depreciation (amounts should be negative)				-2,039,191				
Closing net PP&E (1)				24,516,648				
PP&E Values under MIFRS (Starts from 2012, the transition year)								
Opening net PP&E - Note 1				24,387,754				
Additions				1,887,015				
Depreciation (amounts should be negative)				-1,184,590				
Closing net PP&E (2)				25,090,179				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)				-573,531				
Account 1576 CGAAP Transitional PP&E Amounts								
Opening balance				0	-573531	-430148	-286766	-143383
Amounts added in the year				-573531				
Sub-total				-573531	-573531	-430148	-286766	-143383
Amount of amortization, included in depreciation expense - Note 2					143383	143383	143383	143383
Closing balance in deferral account				-573531	-430148	-286766	-143383	0

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	-143383	**WACC**	5.77%
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	-33093	**Disposition Period - Note 4**	4
Amount Included in Revenue Requirement on rebasing	-176475		

Appendix C – Cost of Power Calculation (Updated)

2013 Load Foreacst	kWh	kW	2011 %RPP
Residential	162,565,618		88%
General Service < 50 kW	54,784,534		86%
General Service 50 to 4,999 kW	141,530,394	396,002	13%
Street Lighting	1,273,281	3,552	0%
Sentinel Lighting	831,977	2,297	96%
Unmetered Scattered Load	1,111,230		95%
Large Use	59,538,701	168,818	0%
TOTAL	421,635,735	570,669	

Electricity - Commodity RPP	2013	2013 Loss			
Class per Load Forecast RPP	Forecasted	Factor		2013	
Residential	142,422,273	1.0532	149,999,138	$0.07932	$11,897,932
General Service < 50 kW	47,144,429	1.0532	49,652,513	$0.07932	$3,938,437
General Service 50 to 4,999 kW	17,709,857	1.0503	18,599,954	$0.07932	$1,475,348
Street Lighting	0	1.0532	0	$0.07932	$0
Sentinel Lighting	799,030	1.0532	841,538	$0.07932	$66,751
Unmetered Scattered Load	1,061,097	1.0532	1,117,547	$0.07932	$88,644
Large Use	0	1.0045	0	$0.07932	$0
TOTAL	209,136,686		220,210,691		$17,467,112

Electricity - Commodity Non-RPP	2013	2013 Loss			
Class per Load Forecast	Forecasted	Factor		2013	
Residential	20,143,345	1.0532	21,214,971	$0.08001	$1,697,410
General Service < 50 kW	7,640,105	1.0532	8,046,558	$0.08001	$643,805
General Service 50 to 4,999 kW	123,820,537	1.0503	130,043,757	$0.08001	$10,404,801
Street Lighting	1,273,281	1.0532	1,341,020	$0.08001	$107,295
Sentinel Lighting	32,947	1.0532	34,700	$0.08001	$2,776
Unmetered Scattered Load	50,133	1.0532	52,800	$0.08001	$4,225
Large Use	59,538,701	1.0045	59,806,625	$0.08001	$4,785,128
TOTAL	212,499,049		160,733,806		$17,645,440

Transmission - Network		Volume			
Class per Load Forecast		Metric		2013	
Residential		kWh	171,214,109	$0.0083	$1,421,077
General Service < 50 kW		kWh	57,699,071	$0.0073	$421,203
General Service 50 to 4,999 kW		kW	396,002	$2.5003	$990,129
Street Lighting		kW	2,272	$2.3353	$5,306
Sentinel Lighting		kW	2,297	$2.3404	$5,376
Unmetered Scattered Load		kWh	1,170,347	$0.0073	$8,544
Large Use		kW	168,818	$1.8264	$308,329
TOTAL					$3,159,964

Transmission - Connection		Volume			
Class per Load Forecast		Metric		2013	
Residential		kWh	171,214,109	$0.0055	$941,678
General Service < 50 kW		kWh	57,699,071	$0.0048	$276,956
General Service 50 to 4,999 kW		kW	396,002	$1.7663	$699,473
Street Lighting		kW	3,552	$1.5269	$5,424
Sentinel Lighting		kW	2,297	$1.5302	$3,515
Unmetered Scattered Load		kWh	1,170,347	$0.0048	$5,618
Large Use		kW	168,818	$2.1853	$368,918
TOTAL					$2,301,580

Appendix C – Cost of Power Calculation (Updated) – Cont'd

Wholesale Market Service Class per Load Forecast			2013		
Residential		kWh	171,214,109	$0.0052	$890,313
General Service < 50 kW		kWh	57,699,071	$0.0052	$300,035
General Service 50 to 4,999 kW		kWh	148,643,712	$0.0052	$772,947
Street Lighting		kWh	1,341,020	$0.0052	$6,973
Sentinel Lighting		kWh	876,238	$0.0052	$4,556
Unmetered Scattered Load		kWh	1,170,347	$0.0052	$6,086
Large Use		kWh	59,806,625	$0.0052	$310,994
TOTAL			**440,751,122**		**$2,291,906**

Rural Rate Assistance Class per Load Forecast			2013		
Residential		kWh	171,214,109	$0.0012	$205,457
General Service < 50 kW		kWh	57,699,071	$0.0012	$69,239
General Service 50 to 4,999 kW		kWh	148,643,712	$0.0012	$178,372
Street Lighting		kWh	1,341,020	$0.0012	$1,609
Sentinel Lighting		kWh	876,238	$0.0012	$1,051
Unmetered Scattered Load		kWh	1,170,347	$0.0012	$1,404
Large Use		kWh	59,806,625	$0.0012	$71,768
TOTAL			**440,751,122**		**$528,901**

	2013
4705-Power Purchased	$35,112,552
4708-Charges-WMS	$2,291,906
4712-IESO Smart Meter Charge	$0
4714-Charges-NW	$3,159,964
4716-Charges-CN	$2,301,580
4730-Rural Rate Assistance	$528,901
4750-Low Voltage	
TOTAL	**43,394,903**

Appendix D – 2013 Customer Load Forecast (Updated)

	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Weather Normal	2013 Weather Normal
Actual kWh Purchases	522,661,540	497,113,270	501,185,430	520,774,860	488,381,990	493,927,030	487,062,910	419,617,213	443,594,623	452,100,623		
Predicted kWh Purchases	516,556,289	503,803,879	499,817,524	522,206,844	490,674,792	488,283,386	465,288,080	446,989,767	451,265,161	441,533,767	443,246,393	443,149,198
% Difference	-1.2%	1.3%	-0.3%	0.3%	0.5%	-1.1%	-4.5%	6.5%	1.7%	-2.3%		
Billed kWh	502,440,916	477,862,795	484,141,790	501,866,998	467,846,213	470,352,000	467,550,816	401,259,942	424,292,841	429,952,199	423,839,436	421,635,734
By Class												
Residential												
Customers	18,178	18,298	18,498	18,756	18,915	18,996	19,137	19,277	19,434	19,724	20,075	20,432
kWh	163,758,008	157,611,434	158,198,542	170,925,879	160,694,398	162,856,080	157,944,948	152,428,518	159,733,338	158,621,921	162,933,476	162,565,618
General Service< 50 kW												
Customers	1,680	1,684	1,683	1,691	1,668	1,657	1,676	1,690	1,691	1,694	1,695	1,696
kWh	47,941,435	46,463,108	49,935,622	52,581,299	50,343,291	53,416,948	55,072,082	54,644,528	54,185,000	54,435,719	54,911,986	54,784,534
General Service> 50 kW												
Customers	239	236	217	208	209	194	176	171	172	170	169	169
kWh	220,590,238	148,754,541	145,858,311	147,125,296	146,968,683	163,224,573	145,113,727	135,381,161	144,932,476	150,174,158	141,983,990	141,530,394
kW	551,946	449,454	418,533	415,116	414,301	441,184	417,425	390,493	432,238	417,210	386,714	386,002
Large User												
Customers	1	3	3	3	3	2	3	3	1	1	1	1
kWh	63,949,901	118,136,694	123,252,607	124,361,165	102,933,628	84,038,365	102,587,954	51,909,228	58,704,363	59,993,492	59,841,663	59,538,701
kW	193,766	293,338	287,801	296,227	313,394	248,610	271,979	195,437	168,338	170,236	169,677	168,818
Streetlights												
Connections	6,412	6,458	6,471	6,520	6,558	6,610	6,671	6,709	6,738	6,750	6,750	6,750
kWh	4,576,874	4,648,825	4,671,053	4,673,771	4,688,652	4,691,239	4,724,654	4,691,957	4,700,576	4,709,765	2,213,639	1,273,281
kW	11,857	12,975	13,024	13,039	13,084	13,086	13,186	13,091	13,119	13,068	6,144	3,552
Sentinel Lights												
Connections	765	758	750	739	732	704	689	680	679	652	574	574
kWh	608,625	1,025,571	1,029,432	1,000,000	1,010,963	980,631	949,655	1,052,725	908,962	894,240	836,210	831,977
kW	2,536	2,929	3,192	2,844	2,812	3,042	2,690	3,631	2,816	2,462	2,297	2,297
Unmetered Loads												
Connections	225	229	232	234	233	232	232	231	227	226	226	225
kWh	1,013,836	1,222,622	1,196,223	1,199,588	1,206,598	1,144,163	1,157,796	1,151,626	1,128,127	1,122,904	1,118,472	1,111,230
Total of Above												
Customer/Connections	27,500	27,665	27,854	28,151	28,317	28,395	28,584	28,761	28,942	29,215	29,489	29,847
kWh	502,440,916	477,862,795	484,141,790	501,866,998	467,846,213	470,352,000	467,550,816	401,259,942	424,292,841	429,952,199	423,839,436	421,635,734
kW from applicable classes	760,106	756,696	722,549	727,226	743,591	705,922	705,280	602,652	616,511	602,976	564,832	570,669

Appendix E – 2013 Other Revenue (Updated)

Revenue Category	2013 Original Application ($)	Interrogatory Adjustments ($)	Settlement Adjustments ($)	2013 Settlement Agreement ($)
Monthly Service Charge-SSA Administration 4080-2	61575	0	0	61575
Microfits 4080-3	1392	33	0	1425
4080 Monthly Service Charge	62967	33	0	63000
4082 Retail Service Revenue Charge	20515	0	0	20515
4084 Service Trans Revenue	789	0	0	789
Rent from Electric Property-Poles*	130,085	0	-95	129,990
Rent from Electric Property-Service Centre	22,552	0	127	22,679
4210 Rent from Electrical Property	152,637	0	32	152,669
Late Payment Charges**	70,849	0	1,122	71,971
4225 Late Payment Charges	70,849	0	1,122	71,971
Misc-Service-Account Status Fee	2,181	0	-38	2,143
Misc Service-NSF Charges	4,515	0	-262	4,253
Misc Service-Occupancy Related	94,238	0	1,326	95,564
Misc Service-Disconnect/Reconnect	14,440	0	5,182	19,622
Misc Service-Mark Up on Work Orders	35,011	0	-818	34,193
4235 Miscellaneous Service Charges	150,385	0	5,390	155,775
Gain on Disposition of Utility and Other Property	0	0	7,911	7,911
4355 Gain on Dispostion of Property	0	0	7,911	7,911
Scrap Metal Sales	10,106	0	6,464	16,570
Misc Service-Other Revenue	8,023	0	1,634	9,657
4390 Miscellaneous Non Operating Income	18,129	0	8,098	26,227
4362 Loss from Retirment of Utility Property	-18,932	18,932	0	0
Interest Earned				
Interest Income-Bank & Miscellaneous	43,750	0	32,393	76,143
Interest Variance Accounts	0	0	0	0
4405 Interest and Diviedend Income	43,750	0	32,393	76,143

Specific Service Charges	150,385	0	5,390	155,775
Late Payment Charges	70,849	0	1,122	71,971
Other Operating Revenues	236,908	33	32	236,973
Other Income or Deductions	42,947	18,932	48,402	110,281
Total	501,089	18,965	54,946	575,000

Appendix F – 2013 PILS (Updated)

2013 PILs Schedule

Description	Source or Input	Tax Payable
Deemed Income	Rev Def	1,122,889
Tax Adj to Accounting Income	Rev Def	(789,326)
Taxable Income		**333,563**
Combined Income Tax Rate	PILs Rates	19.500%
Total Income Taxes		**65,045**
Investment Tax Credits		
Apprentice Tax Credits		22,000
Other Tax Credits (SBD)		-
Total PILS Before Gross Up	**12.90%**	**43,045**
Gross Up PILS	**43045/(1-.195)**	**53,472**

2013 Total Taxes

Description	Tax Payable
Total PILS After Gross Up	53,472
Total PILS After Gross Up	53,472

Appendix G – 2013 Cost of Capital (Updated)

Appendix 2-OB
Debt Instruments

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

Test Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	
1	Long Term Note Payable	City of Welland	Affiliated	Fixed Rate	16-Oct-05		$ 13,499,953	0.0403	$ 544,048.11	Actual Rate 6.25%
2	Long Term Loan	TD Securities	Third-Party	Fixed Rate	6-Feb-09	5	$ 3,700,000	0.0287	$ 106,190.00	Swap - Fixed Rate
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 17,199,953	0.0378	$ 650,238.11	

Appendix 2-OA
Capital Structure and Cost of Capital-2013 Test Year

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

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$17,604,086	3.78%	$665,434
2	Short-term Debt	4.00%	(1)	$1,257,435	2.08%	$26,155
3	**Total Debt**	60.0%		$18,861,520	3.67%	$691,589
	Equity					
4	Common Equity	40.00%		$12,574,347	8.93%	$1,122,889
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$12,574,347	8.93%	$1,122,889
7	**Total**	100.0%		$31,435,867	5.77%	$1,814,478

Appendix H – 2013 Revenue Deficiency (Updated)

Welland Hydro Electric System Corp.
Revenue Deficiency Determination

Description	2013 Test Existing Rates	2013 Test - Required Revenue
Revenue		
Revenue Deficiency		**-289,566**
Distribution Revenue	9,004,606	9,004,606
Other Operating Revenue (Net)	575,000	575,000
Total Revenue	**9,579,606**	**9,290,040**
Costs and Expenses		
Administrative & General, Billing & Collecting	3,356,191	3,356,191
Operation & Maintenance	3,013,809	3,013,809
Depreciation & Amortization	1,085,182	1,085,182
PPE Return on Rate Base	-33,093	-33,093
Deemed Interest	691,589	691,589
Total Costs and Expenses	**8,113,678**	**8,113,678**
Utility Income Before Income Taxes	**1,465,928**	**1,176,362**
Income Taxes:		
Corporate Income Taxes	109,938	53,472
Total Income Taxes	**109,938**	**53,472**
Utility Net Income	**1,355,990**	**1,122,890**
Income Tax Expense Calculation:		
Deemed Income		1,122,889
Accounting Income	1,465,928	
Tax Adjustments to Accounting Income	-789,326	-789,326
Taxable Income	**676,602**	**333,563**
Income Tax Expense	109,938	
Grossed Up PILS		53,472
Tax Rate Refecting Tax Credits	16.25%	16.03%
Actual Return on Rate Base:		
Rate Base	31,435,868	31,435,868
Interest Expense	691,589	691,589
Net Income	1,355,990	1,122,890
Total Actual Return on Rate Base	**2,047,579**	**1,814,479**
Actual Return on Rate Base	6.51%	5.77%
Required Return on Rate Base:		
Rate Base	31,435,868	31,435,868
Deemed Interest Expense	691,589	691,589
Return On Equity	1,122,889	1,122,889
Total Required Return on Rate Base:	**1,814,478**	**1,814,478**
Expected Return on Rate Base	5.77%	5.77%
Revenue Deficiency After Tax	**-233,101**	**-1**
Revenue Deficiency Before Tax	**-289,566**	**-1**

Tax Exhibit	**2013**
Deemed Utility Income	1,122,890
Tax Adjustments to Accounting Income	(789,326)
Taxable Income prior to adjusting revenue to PILs	**333,564**
Tax Rate After Apprentice Tax Deductions	12.90%
Total PILs before gross up	**43,045**
Grossed up PILs	**53,472**

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

Welland Hydro-Electric System Corp.
PROPOSED TARIFF OF RATES AND CHARGES
Proposed Effective and Implementation Date May 1, 2013

RESIDENTIAL SERVICE CLASSIFICATION
This classification refers to the supply of electrical energy to residential customers residing in detached or semi-detached units, as defined in the local zoning by-law. 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.

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	$	15.66
Rate Rider for Stranded Meters – in effect until April 30, 2017	$	0.45
Distribution Volumetric Rate	$/kWh	0.0133
Rate Rider for Deferral/ Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0016)
Rate Rider for Global Adjustment Sub-Account (2012) – applicable only to Non-RPP Customers – effective until April 30, 2014	$/kWh	(0.0003)
Rate Rider for Deferral/ Variance Account Disposition (2013) – effective until April 30, 2015	$/kWh	0.0003
Rate Rider for Global Adjustment Sub-Account (2013) – applicable only to Non-RPP Customers – effective until April 30, 2015	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0083
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0055

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Welland Hydro-Electric System Corp.
PROPOSED TARIFF OF RATES AND CHARGES
Proposed Effective and Implementation Date May 1, 2013

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to commercial buildings taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Commercial buildings are defined as buildings, which are used for purposes other than resident dwellings. 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.

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	$	27.83
Rate Rider for Stranded Meters – effective until April 30, 2017	$	0.48
Distribution Volumetric Rate	$/kWh	0.0082
Rate Rider for Deferral/ Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0015)
Rate Rider for Global Adjustment Sub-Account (2012) – applicable only to Non-RPP Customers – effective until April 30, 2014	$/kWh	(0.0003)
Rate Rider for Deferral/ Variance Account Disposition (2013) – effective until April 30, 2015	$/kWh	0.0003
Rate Rider for Global Adjustment Sub-Account (2013) – applicable only to Non-RPP Customers – effective until April 30, 2015	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0073
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Welland Hydro-Electric System Corp.
PROPOSED TARIFF OF RATES AND CHARGES
Proposed Effective and Implementation Date May 1, 2013

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to commercial buildings whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Commercial buildings are defined as buildings, which are used for purposes other than resident dwellings. 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.
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	$	267.94
Distribution Volumetric Rate	$/kW	2.3435
Rate Rider for Deferral/ Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.5226)
Rate Rider for Global Adjustment Sub-Account (2012) – applicable only to Non-RPP Customers – effective until April 30, 2014	$/kW	(0.0995)
Rate Rider for Deferral/ Variance Account Disposition (2013) – effective until April 30, 2015	$/kW	0.0995
Rate Rider for Global Adjustment Sub-Account (2013) – applicable only to Non-RPP Customers – effective until April 30, 2015	$/kW	0.0992
Retail Transmission Rate – Network Service Rate	$/kW	2.5129
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6428
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.4926
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9679

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Welland Hydro-Electric System Corp.
PROPOSED TARIFF OF RATES AND CHARGES
Proposed Effective and Implementation Date May 1, 2013

LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater 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.

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	$	7,676.01
Distribution Volumetric Rate	$/kW	0.7948
Rate Rider for Deferral/ Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.5277)
Rate Rider for Global Adjustment Sub-Account (2012) – applicable only to Non-RPP Customers – effective until April 30, 2014	$/kW	(0.1010)
Rate Rider for Deferral/ Variance Account Disposition (2013) – effective until April 30, 2015	$/kW	0.0982
Rate Rider for Global Adjustment Sub-Account (2013) – applicable only to Non-RPP Customers – effective until April 30, 2015	$/kW	0.0979
Retail Transmission Rate – Network Service Rate	$/kW	1.8264
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.1853

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Welland Hydro-Electric System Corp.
PROPOSED TARIFF OF RATES AND CHARGES
Proposed Effective and Implementation Date May 1, 2013

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Unmetered or flat connections are permitted with the approval of Welland Hydro-Electric System Corp. Engineering Department. Flat rate connects may include, but are not limited to, Traffic Lights, Street Lights, Bus Shelters, and Signs. Energy consumption is determined by information provided by the customer and/or load measurement taken by Welland Hydro-Electric System Corp. following connection of the flat service. 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.
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)	$	11.35
Distribution Volumetric Rate	$/kWh	0.0075
Rate Rider for Deferral/ Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0016)
Rate Rider for Global Adjustment Sub-Account (2012) – applicable only to Non-RPP Customers – effective until April 30, 2014	$/kWh	(0.0003)
Rate Rider for Deferral/ Variance Account Disposition (2013) – effective until April 30, 2015	$/kWh	0.0003
Rate Rider for Global Adjustment Sub-Account (2013) – applicable only to Non-RPP Customers – effective until April 30, 2015	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0073
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Welland Hydro-Electric System Corp.
PROPOSED TARIFF OF RATES AND CHARGES
Proposed Effective and Implementation Date May 1, 2013

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting not classified as unmetered or street lighting. The consumption for the customer will be based on the calculated connected load times a twelve hour day times the applicable billing period. 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.
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)	$	2.56
Distribution Volumetric Rate	$/kW	5.7365
Rate Rider for Deferral/ Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.5529)
Rate Rider for Global Adjustment Sub-Account (2012) – applicable only to Non-RPP Customers – effective until April 30, 2014	$/kW	(0.1026)
Rate Rider for Deferral/ Variance Account Disposition (2013) – effective until April 30, 2015	$/kW	0.1009
Rate Rider for Global Adjustment Sub-Account (2013) – applicable only to Non-RPP Customers – effective until April 30, 2015	$/kW	0.1005
Retail Transmission Rate – Network Service Rate	$/kW	2.3404
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5302

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Welland Hydro-Electric System Corp.
PROPOSED TARIFF OF RATES AND CHARGES
Proposed Effective and Implementation Date May 1, 2013

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to the Street Lighting system owned by the City of Welland. Welland Hydro-Electric System Corp. provides new installations and maintenance of the street lighting system, as required by the City of Welland. 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.
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)	$	1.89
Distribution Volumetric Rate	$/kW	7.9541
Rate Rider for Deferral/ Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.5679)
Rate Rider for Global Adjustment Sub-Account (2012) – applicable only to Non-RPP Customers – effective until April 30, 2014	$/kW	(0.1043)
Rate Rider for Deferral/ Variance Account Disposition (2013) – effective until April 30, 2015	$/kW	0.0998
Rate Rider for Global Adjustment Sub-Account (2013) – applicable only to Non-RPP Customers – effective until April 30, 2015	$/kW	0.0995
Retail Transmission Rate – Network Service Rate	$/kW	2.3353
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5269

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Welland Hydro-Electric System Corp.
PROPOSED TARIFF OF RATES AND CHARGES
Proposed Effective and Implementation Date May 1, 2013

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.

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.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.40

Welland Hydro-Electric System Corp.
PROPOSED TARIFF OF RATES AND CHARGES
Proposed Effective and Implementation Date May 1, 2013

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.70)
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.

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

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Account history	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
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
Disconnect / Reconnect at meter - during regular hours	$	65.00
Install / Remove load control device - during regular hours	$	65.00
Disconnect / Reconnect at meter - after regular hours	$	185.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Meter upgrade requested by customer plus installation – per month plus installation on a time and material basis.	$	10.00

Welland Hydro-Electric System Corp.
PROPOSED TARIFF OF RATES AND CHARGES
Proposed Effective and Implementation Date May 1, 2013

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	1.0532
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0427
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Appendix J - Updated Customer Impact - Residential(Updated)

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 800 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 16.5500	1	$ 16.55	$ 15.6600	1	$ 15.66	-$ 0.89	-5.38%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Residual	Monthly	-$ 0.2400	1	-$ 0.24	$ -	1	$ -	$ 0.24	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.4500	1	$ 0.45	$ 0.45	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0141	800	$ 11.28	$ 0.0133	800	$ 10.64	-$ 0.64	-5.67%
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
Disposition-Residual Smart			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A				$ 27.59			$ 26.75	-$ 0.84	-3.04%
Deferral/Variance Account	per kWh	-$ 0.0016	800	-$ 1.28	-$ 0.0016	800	-$ 1.28	$ -	0.00%
Deferral/Variance Account	per kWh		800	$ -	$ 0.0003	800	$ 0.24	$ 0.24	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge			800	$ -		800	$ -	$ -	
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution				$ 26.31			$ 25.71	-$ 0.60	-2.28%
RTSR - Network	per kWh	$ 0.0080	843	$ 6.74	$ 0.0083	843	$ 6.99	$ 0.25	3.75%
RTSR - Line and	per kWh	$ 0.0056	843	$ 4.72	$ 0.0055	843	$ 4.63	-$ 0.08	-1.79%
Sub-Total C - Delivery				$ 37.77			$ 37.34	-$ 0.43	-1.14%
Wholesale Market Service	per kWh	$ 0.0052	843	$ 4.38	$ 0.0052	843	$ 4.38	$ -	0.00%
Rural and Remote Rate	per kWh	$ 0.0011	843	$ 0.93	$ 0.0011	843	$ 0.93	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	843	$ 5.90	$ 0.0070	843	$ 5.90	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0740	600	$ 44.40	$ 0.0740	600	$ 44.40	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0870	243	$ 21.10	$ 0.0870	243	$ 21.10	$ -	0.00%
TOU - Off Peak		$ 0.0630	539	$ 33.97	$ 0.0630	539	$ 33.97	$ -	0.00%
TOU - Mid Peak		$ 0.0990	152	$ 15.01	$ 0.0990	152	$ 15.01	$ -	0.00%
TOU - On Peak		$ 0.1180	152	$ 17.90	$ 0.1180	152	$ 17.90	$ -	0.00%
Total Bill on RPP (before Taxes)				$ 114.73			$ 114.30	-$ 0.43	-0.38%
HST		13%		$ 14.91	13%		$ 14.86	-$ 0.06	-0.38%
Total Bill (including HST)				$ 129.64			$ 129.15	-$ 0.49	-0.38%
Ontario Clean Energy Benefit [1]				-$ 12.96			-$ 12.92	$ 0.04	-0.31%
Total Bill on RPP (including OCEB)				$ 116.68			$ 116.23	-$ 0.45	-0.38%
Total Bill on TOU (before Taxes)				$ 116.11			$ 115.68	-$ 0.43	-0.37%
HST		13%		$ 15.09	13%		$ 15.04	-$ 0.06	-0.37%
Total Bill (including HST)				$ 131.20			$ 130.71	-$ 0.49	-0.37%
Ontario Clean Energy Benefit [1]				-$ 13.12			-$ 13.07	$ 0.05	-0.38%
Total Bill on TOU (including OCEB)				$ 118.08			$ 117.64	-$ 0.44	-0.37%

	Current	Proposed
Loss Factor (%)	5.3200%	5.3200%

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

Appendix 2-W
Bill Impacts

Customer Class: **GS<50 kW**

Consumption 2000 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct

	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	$ 28.7500	1	$ 28.75	$ 27.8300	1	$ 27.83	-$ 0.92	-3.20%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Residual	Monthly	-$ 0.3000	1	-$ 0.30	$ -	1	$ -	$ 0.30	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.4800	1	$ 0.48	$ 0.48	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0085	2000	$ 17.00	$ 0.0082	2000	$ 16.40	-$ 0.60	-3.53%
Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rate Rider			2000	$ -		2000	$ -	$ -	
Disposition-Residual Smart			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 45.45			$ 44.71	**-$ 0.74**	**-1.63%**
Deferral/Variance Account	per kWh	-$ 0.0015	2000	-$ 3.00	-$ 0.0015	2000	-$ 3.00	$ -	0.00%
Deferral/Variance Account	per kWh		2000	$ -	$ 0.0003	2000	$ 0.60	$ 0.60	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Low Voltage Service Charge			2000	$ -		2000	$ -	$ -	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution				**$ 42.45**			**$ 42.31**	**-$ 0.14**	**-0.33%**
RTSR - Network	per kWh	$ 0.0071	2106	$ 14.96	$ 0.0073	2106	$ 15.38	$ 0.42	2.82%
RTSR - Line and	per kWh	$ 0.0049	2106	$ 10.32	$ 0.0048	2106	$ 10.11	-$ 0.21	-2.04%
Sub-Total C - Delivery				**$ 67.73**			**$ 67.80**	**$ 0.07**	**0.10%**
Wholesale Market Service	per kWh	$ 0.0052	2106	$ 10.95	$ 0.0052	2106	$ 10.95	$ -	0.00%
Rural and Remote Rate	per kWh	$ 0.0011	2106	$ 2.32	$ 0.0011	2106	$ 2.32	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2106	$ 14.74	$ 0.0070	2106	$ 14.74	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0740	600	$ 44.40	$ 0.0740	600	$ 44.40	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0870	1506	$ 131.06	$ 0.0870	1506	$ 131.06	$ -	0.00%
TOU - Off Peak		$ 0.0630	1348	$ 84.93	$ 0.0630	1348	$ 84.93	$ -	0.00%
TOU - Mid Peak		$ 0.0990	379	$ 37.54	$ 0.0990	379	$ 37.54	$ -	0.00%
TOU - On Peak		$ 0.1180	379	$ 44.74	$ 0.1180	379	$ 44.74	$ -	0.00%
Total Bill on RPP (before Taxes)				**$ 271.45**			**$ 271.52**	**$ 0.07**	**0.03%**
HST		13%		$ 35.29	13%		$ 35.30	$ 0.01	0.03%
Total Bill (including HST)				$ 306.74			$ 306.82	$ 0.08	0.03%
Ontario Clean Energy Benefit [1]				-$ 30.67			-$ 30.68	-$ 0.01	0.03%
Total Bill on RPP (including OCEB)				**$ 276.07**			**$ 276.14**	**$ 0.07**	**0.03%**
Total Bill on TOU (before Taxes)				**$ 263.20**			**$ 263.27**	**$ 0.07**	**0.03%**
HST		13%		$ 34.22	13%		$ 34.22	$ 0.01	0.03%
Total Bill (including HST)				$ 297.41			$ 297.49	$ 0.08	0.03%
Ontario Clean Energy Benefit [1]				-$ 29.74			-$ 29.75	-$ 0.01	0.03%
Total Bill on TOU (including OCEB)				**$ 267.67**			**$ 267.74**	**$ 0.07**	**0.03%**

Loss Factor (%) Current: 5.3200% Proposed: 5.3200%

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

Appendix 2-W

Bill Impacts

Customer Class: **GS>50**

Consumption 60 kW / 32400 kWh

◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 339.4900	1	$ 339.49	$ 267.9400	1	$ 267.94	-$ 71.55	-21.08%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Residual	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.3978	60	$ 83.87	$ 2.3435	60	$ 140.61	$ 56.74	67.66%
Smart Meter Disposition Rider			60	$ -		60	$ -	$ -	
LRAM & SSM Rate Rider			60	$ -		60	$ -	$ -	
Disposition-Residual Smart			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
Sub-Total A				$ 423.36			$ 408.55	**-$ 14.81**	**-3.50%**
Deferral/Variance Account	per kW	-$ 0.5226	60	-$ 31.36	-$ 0.5226	60	-$ 31.36	$ -	0.00%
Deferral/Variance Account	per kW		60	$ -	$ 0.0995	60	$ 5.97	$ 5.97	
Deferral/Variance Account	per kW	-$ 0.0995	60	-$ 5.97	-$ 0.0995	60	-$ 5.97	$ -	0.00%
Deferral/Variance Account	per kW		60	$ -	$ 0.0992	60	$ 5.95	$ 5.95	
Low Voltage Service Charge			60	$ -		60	$ -	$ -	
Smart Meter Entity Charge						60	$ -	$ -	
Sub-Total B - Distribution				**$ 386.03**			**$ 383.15**	**-$ 2.89**	**-0.75%**
RTSR - Network	per kW	$ 2.4354	63	$ 153.90	$ 2.5129	63	$ 158.80	$ 4.90	3.18%
RTSR - Line and	per kW	$ 1.6828	63	$ 106.34	$ 1.6428	63	$ 103.81	-$ 2.53	-2.38%
Sub-Total C - Delivery				**$ 646.27**			**$ 645.75**	**-$ 0.52**	**-0.08%**
Wholesale Market Service	per kWh	$ 0.0052	34124	$ 177.44	$ 0.0052	34124	$ 177.44	$ -	0.00%
Rural and Remote Rate	per kWh	$ 0.0011	34124	$ 37.54	$ 0.0011	34124	$ 37.54	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	34124	$ 238.87	$ 0.0070	34124	$ 238.87	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0630	21839	$ 1,375.87	$ 0.0630	21839	$ 1,375.87	$ -	0.00%
TOU - Mid Peak		$ 0.0990	6142	$ 608.08	$ 0.0990	6142	$ 608.08	$ -	0.00%
TOU - On Peak		$ 0.1180	6142	$ 724.79	$ 0.1180	6142	$ 724.79	$ -	0.00%
Total Bill on RPP (before Taxes)				$ -			$ -	$ -	
HST		13%		$ -	13%		$ -	$ -	
Total Bill (including HST)				$ -			$ -	$ -	
***Ontario Clean Energy Benefit* [1]**				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				$ -			$ -	$ -	
Total Bill on TOU (before Taxes)				$ 3,809.10			$ 3,808.59	**-$ 0.52**	**-0.01%**
HST		13%		$ 495.18	13%		$ 495.12	-$ 0.07	-0.01%
Total Bill (including HST)				$ 4,304.29			$ 4,303.70	-$ 0.58	-0.01%
***Ontario Clean Energy Benefit* [1]**				-$ 430.43			-$ 430.37	$ 0.06	-0.01%
Total Bill on TOU (including OCEB)				$ 3,873.86			$ 3,873.33	-$ 0.52	-0.01%

Loss Factor (%) 5.3200% 5.3200%

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

Appendix 2-W
Bill Impacts

Customer Class: **GS>50**

Consumption 60 kW · 10000 kWh

◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct

	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	$ 339.4900	1	$ 339.49	$ 267.9400	1	$ 267.94	-$ 71.55	-21.08%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Residual	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.3978	60	$ 83.87	$ 2.3435	60	$ 140.61	$ 56.74	67.66%
Smart Meter Disposition Rider			60	$ -		60	$ -	$ -	
LRAM & SSM Rate Rider			60	$ -		60	$ -	$ -	
Disposition-Residual Smart			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
Sub-Total A				$ 423.36			$ 408.55	-$ **14.81**	**-3.50%**
Deferral/Variance Account	per kW	-$ 0.5226	60	-$ 31.36	-$ 0.5226	60	-$ 31.36	$ -	0.00%
Deferral/Variance Account	per kW		60	$ -	$ 0.0995	60	$ 5.97	$ 5.97	
Deferral/Variance Account	per kW	-$ 0.0995	60	-$ 5.97	-$ 0.0995	60	-$ 5.97	$ -	0.00%
Deferral/Variance Account	per kW		60	$ -	$ 0.0992	60	$ 5.95	$ 5.95	
Low Voltage Service Charge			60	$ -		60	$ -	$ -	
Smart Meter Entity Charge						60	$ -	$ -	
Sub-Total B - Distribution				$ **386.03**			$ **383.15**	-$ **2.89**	**-0.75%**
RTSR - Network	per kW	$ 2.4354	63	$ 153.90	$ 2.5129	63	$ 158.80	$ 4.90	3.18%
RTSR - Line and	per kW	$ 1.6828	63	$ 106.34	$ 1.6428	63	$ 103.81	-$ 2.53	-2.38%
Sub-Total C - Delivery				$ **646.27**			$ **645.75**	-$ **0.52**	**-0.08%**
Wholesale Market Service	per kWh	$ 0.0052	10532	$ 54.77	$ 0.0052	10532	$ 54.77	$ -	0.00%
Rural and Remote Rate	per kWh	$ 0.0011	10532	$ 11.59	$ 0.0011	10532	$ 11.59	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	10532	$ 73.72	$ 0.0070	10532	$ 73.72	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0630	6740	$ 424.65	$ 0.0630	6740	$ 424.65	$ -	0.00%
TOU - Mid Peak		$ 0.0990	1896	$ 187.68	$ 0.0990	1896	$ 187.68	$ -	0.00%
TOU - On Peak		$ 0.1180	1896	$ 223.70	$ 0.1180	1896	$ 223.70	$ -	0.00%
Total Bill on RPP (before Taxes)				$ -			$ -	$ -	
HST		13%		$ -	13%		$ -	$ -	
Total Bill (including HST)				$ -			$ -	$ -	
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				$ -			$ -	$ -	
Total Bill on TOU (before Taxes)				$ 1,622.63			$ 1,622.11	-$ 0.52	-0.03%
HST		13%		$ 210.94	13%		$ 210.87	-$ 0.07	-0.03%
Total Bill (including HST)				$ 1,833.57			$ 1,832.98	-$ 0.58	-0.03%
Ontario Clean Energy Benefit [1]				-$ 183.36			-$ 183.30	$ 0.06	-0.03%
Total Bill on TOU (including OCEB)				$ **1,650.21**			$ **1,649.68**	-$ **0.52**	**-0.03%**

Loss Factor (%) Current: 5.3200% · Proposed: 5.3200%

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

Appendix 2-W
Bill Impacts

Customer Class: **GS>50**

Consumption 250 kW ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct
50400 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 339.4900	1	$ 339.49	$ 267.9400	1	$ 267.94	-$ 71.55	-21.08%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Residual	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.3978	250	$ 349.45	$ 2.3435	250	$ 585.88	$ 236.43	67.66%
Smart Meter Disposition Rider			250	$ -		250	$ -	$ -	
LRAM & SSM Rate Rider			250	$ -		250	$ -	$ -	
Disposition-Residual Smart			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Sub-Total A				$ 688.94			$ 853.82	**$ 164.88**	**23.93%**
Deferral/Variance Account	per kW	-$ 0.5226	250	-$ 130.65	-$ 0.5226	250	-$ 130.65	$ -	0.00%
Deferral/Variance Account	per kW		250	$ -	$ 0.0995	250	$ 24.88	$ 24.88	
Deferral/Variance Account	per kW	-$ 0.0995	250	-$ 24.88	-$ 0.0995	250	-$ 24.88	$ -	0.00%
Deferral/Variance Account	per kW		250	$ -	$ 0.0992	250	$ 24.80	$ 24.80	
Low Voltage Service Charge			250	$ -		250	$ -	$ -	
Smart Meter Entity Charge						250	$ -	$ -	
Sub-Total B - Distribution				**$ 533.42**			**$ 747.97**	**$ 214.55**	**40.22%**
RTSR - Network	per kW	$ 2.4354	263	$ 641.24	$ 2.5129	263	$ 661.65	$ 20.41	3.18%
RTSR - Line and	per kW	$ 1.6828	263	$ 443.08	$ 1.6428	263	$ 432.55	-$ 10.53	-2.38%
Sub-Total C - Delivery				**$ 1,617.74**			**$ 1,842.16**	**$ 224.42**	**13.87%**
Wholesale Market Service	per kWh	$ 0.0052	53081	$ 276.02	$ 0.0052	53081	$ 276.02	$ -	0.00%
Rural and Remote Rate	per kWh	$ 0.0011	53081	$ 58.39	$ 0.0011	53081	$ 58.39	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	53081	$ 371.57	$ 0.0070	53081	$ 371.57	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0630	33972	$ 2,140.24	$ 0.0630	33972	$ 2,140.24	$ -	0.00%
TOU - Mid Peak		$ 0.0990	9555	$ 945.91	$ 0.0990	9555	$ 945.91	$ -	0.00%
TOU - On Peak		$ 0.1180	9555	$ 1,127.45	$ 0.1180	9555	$ 1,127.45	$ -	0.00%
Total Bill on RPP (before Taxes)				$ -			$ -	$ -	
HST		13%		$ -	13%		$ -	$ -	
Total Bill (including HST)				$ -			$ -	$ -	
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				$ -			$ -	$ -	
Total Bill on TOU (before Taxes)				$ 6,537.56			$ 6,761.98	$ 224.42	3.43%
HST		13%		$ 849.88	13%		$ 879.06	$ 29.18	3.43%
Total Bill (including HST)				$ 7,387.44			$ 7,641.04	$ 253.60	3.43%
Ontario Clean Energy Benefit [1]				-$ 738.74			-$ 764.10	-$ 25.36	3.43%
Total Bill on TOU (including OCEB)				$ 6,648.70			$ 6,876.94	$ 228.24	3.43%

Loss Factor (%) 5.3200% 5.3200%

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

Appendix 2-W
Bill Impacts

Customer Class: **GS>50**

Consumption 4100 kW, 1330000 kWh

◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	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	$ 339.4900	1	$ 339.49	$ 267.9400	1	$ 267.94	-$ 71.55	-21.08%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Residual	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.3978	4100	$ 5,730.98	$ 2.3435	4100	$ 9,608.35	$ 3,877.37	67.66%
Smart Meter Disposition Rider			4100	$ -		4100	$ -	$ -	
LRAM & SSM Rate Rider			4100	$ -		4100	$ -	$ -	
Disposition-Residual Smart			4100	$ -		4100	$ -	$ -	
Transformer Allowance	per kW	-$ 0.7000	4100	-$ 2,870.00	-$ 0.7000	4100	-$ 2,870.00	$ -	0.00%
			4100	$ -		4100	$ -	$ -	
			4100	$ -		4100	$ -	$ -	
			4100	$ -		4100	$ -	$ -	
			4100	$ -		4100	$ -	$ -	
			4100	$ -		4100	$ -	$ -	
Sub-Total A				$ 3,200.47			$ 7,006.29	$ 3,805.82	118.91%
Deferral/Variance Account	per kW	-$ 0.5226	4100	-$ 2,142.66	-$ 0.5226	4100	-$ 2,142.66	$ -	0.00%
Deferral/Variance Account	per kW		4100	$ -	$ 0.0995	4100	$ 407.95	$ 407.95	
Deferral/Variance Account	per kW	-$ 0.0995	4100	-$ 407.95	-$ 0.0995	4100	-$ 407.95	$ -	0.00%
Deferral/Variance Account	per kW		4100	$ -	$ 0.0992	4100	$ 406.72	$ 406.72	
Low Voltage Service Charge			4100	$ -		4100	$ -	$ -	
Smart Meter Entity Charge						4100	$ -	$ -	
Sub-Total B - Distribution				$ 649.86			$ 5,270.35	$ 4,620.49	711.00%
RTSR - Network	per kW	$ 2.4354	4275	$ 10,411.51	$ 2.5129	4275	$ 10,742.82	$ 331.32	3.18%
RTSR - Line and	per kW	$ 1.6828	4275	$ 7,194.09	$ 1.6428	4275	$ 7,023.08	-$ 171.00	-2.38%
Sub-Total C - Delivery				$ 18,255.45			$ 23,036.26	$ 4,780.81	26.19%
Wholesale Market Service	per kWh	$ 0.0052	1386791	$ 7,211.31	$ 0.0052	1386791	$ 7,211.31	$ -	0.00%
Rural and Remote Rate	per kWh	$ 0.0011	1386791	$ 1,525.47	$ 0.0011	1386791	$ 1,525.47	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1386791	$ 9,707.54	$ 0.0070	1386791	$ 9,707.54	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0630	887546	$ 55,915.41	$ 0.0630	887546	$ 55,915.41	$ -	0.00%
TOU - Mid Peak		$ 0.0990	249622	$ 24,712.62	$ 0.0990	249622	$ 24,712.62	$ -	0.00%
TOU - On Peak		$ 0.1180	249622	$ 29,455.44	$ 0.1180	249622	$ 29,455.44	$ -	0.00%
Total Bill on RPP (before Taxes)				$ -			$ -	$ -	
HST		13%		$ -	13%		$ -	$ -	
Total Bill (including HST)				$ -			$ -	$ -	
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				$ -			$ -	$ -	
Total Bill on TOU (before Taxes)				$ 146,783.49			$ 151,564.30	$ 4,780.81	3.26%
HST		13%		$ 19,081.85	13%		$ 19,703.36	$ 621.50	3.26%
Total Bill (including HST)				$ 165,865.35			$ 171,267.66	$ 5,402.31	3.26%
Ontario Clean Energy Benefit [1]				-$ 16,586.53			-$ 17,126.77	-$ 540.24	3.26%
Total Bill on TOU (including OCEB)				$ 149,278.82			$ 154,140.89	$ 4,862.07	3.26%

Loss Factor (%) — Current: 4.2700% — Proposed: 4.2700%

Appendix J - Updated Customer Impact – Large Use (Updated)

Appendix 2-W
Bill Impacts

Customer Class: Large Use

Consumption 13972 kW
4927894 kWh

◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 12,986.1400	1	$ 12,986.14	$ 7,676.0100	1	$ 7,676.01	-$ 5,310.13	-40.89%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Residual	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 0.8604	13972	$ 12,021.51	$ 0.7948	13972	$ 11,104.95	-$ 916.56	-7.62%
Smart Meter Disposition Rider			13972	$ -		13972	$ -	$ -	
LRAM & SSM Rate Rider			13972	$ -		13972	$ -	$ -	
Disposition-Residual Smart			13972	$ -		13972	$ -	$ -	
Transformer Allowance	per kW	-$ 0.7000	13972	-$ 9,780.40	-$ 0.7000	13972	-$ 9,780.40	$ -	0.00%
			13972	$ -		13972	$ -	$ -	
			13972	$ -		13972	$ -	$ -	
			13972	$ -		13972	$ -	$ -	
			13972	$ -		13972	$ -	$ -	
			13972	$ -		13972	$ -	$ -	
Sub-Total A				$ 15,227.25			$ 9,000.56	-$ 6,226.69	-40.89%
Deferral/Variance Account	per kW	-$ 0.5277	13972	-$ 7,373.02	-$ 0.5277	13972	-$ 7,373.02	$ -	0.00%
Deferral/Variance Account	per kW		13972	$ -	$ 0.0982	13972	$ 1,372.05	$ 1,372.05	
Deferral/Variance Account	per kW	-$ 0.1010	13972	-$ 1,411.17	-$ 0.1010	13972	-$ 1,411.17	$ -	0.00%
Deferral/Variance Account	per kW		13972	$ -	$ 0.0979	13972	$ 1,367.86	$ 1,367.86	
Low Voltage Service Charge			13972	$ -		13972	$ -	$ -	
Smart Meter Entity Charge						13972	$ -	$ -	
Sub-Total B - Distribution				$ 6,443.05			$ 2,956.27	-$ 3,486.78	-54.12%
RTSR - Network	per kW	$ 1.7701	14035	$ 24,843.13	$ 1.8264	14035	$ 25,633.29	$ 790.16	3.18%
RTSR - Line and	per kW	$ 2.2384	14035	$ 31,415.66	$ 2.1853	14035	$ 30,670.41	-$ 745.25	-2.37%
Sub-Total C - Delivery				$ 62,701.84			$ 59,259.97	-$ 3,441.87	-5.49%
Wholesale Market Service	per kWh	$ 0.0052	4950070	$ 25,740.36	$ 0.0052	4950070	$ 25,740.36	$ -	0.00%
Rural and Remote Rate	per kWh	$ 0.0011	4950070	$ 5,445.08	$ 0.0011	4950070	$ 5,445.08	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	4950070	$ 34,650.49	$ 0.0070	4950070	$ 34,650.49	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0740		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0630	3168044	$ 199,586.80	$ 0.0630	3168044	$ 199,586.80	$ -	0.00%
TOU - Mid Peak		$ 0.0990	891013	$ 88,210.24	$ 0.0990	891013	$ 88,210.24	$ -	0.00%
TOU - On Peak		$ 0.1180	891013	$ 105,139.48	$ 0.1180	891013	$ 105,139.48	$ -	0.00%
Total Bill on RPP (before Taxes)				$ -			$ -	$ -	
HST		13%		$ -	13%		$ -	$ -	
Total Bill (including HST)				$ -			$ -	$ -	
Ontario Clean Energy Benefit [1]				$ -			$ -	$ -	
Total Bill on RPP (including OCEB)				$ -			$ -	$ -	
Total Bill on TOU (before Taxes)				$ 521,474.54			$ 518,032.67	-$ 3,441.87	-0.66%
HST		13%		$ 67,791.69	13%		$ 67,344.25	-$ 447.44	-0.66%
Total Bill (including HST)				$ 589,266.23			$ 585,376.91	-$ 3,889.32	-0.66%
Ontario Clean Energy Benefit [1]				-$ 58,926.62			-$ 58,537.69	$ 388.93	-0.66%
Total Bill on TOU (including OCEB)				$ 530,339.61			$ 526,839.22	-$ 3,500.39	-0.66%

Loss Factor (%) 0.4500% 0.4500%

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

Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption 150 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 13.5400	1	$ 13.54	$ 11.3500	1	$ 11.35	-$ 2.19	-16.17%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Residual	Monthly		1	$ -	$ -	1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0089	150	$ 1.34	$ 0.0075	150	$ 1.13	-$ 0.21	-15.73%
Smart Meter Disposition Rider			150	$ -		150	$ -	$ -	
LRAM & SSM Rate Rider			150	$ -		150	$ -	$ -	
Disposition-Residual Smart			150	$ -		150	$ -	$ -	
			150	$ -		150	$ -	$ -	
Sub-Total A				$ 14.88			$ 12.48	**-$ 2.40**	**-16.13%**
Deferral/Variance Account	per kWh	-$ 0.0016	150	-$ 0.24	-$ 0.0016	150	-$ 0.24	$ -	0.00%
Deferral/Variance Account	per kWh		150	$ -	$ 0.0003	150	$ 0.05	$ 0.05	
			150	$ -		150	$ -	$ -	
Low Voltage Service Charge			150	$ -		150	$ -	$ -	
Smart Meter Entity Charge						150	$ -	$ -	
Sub-Total B - Distribution				**$ 14.64**			**$ 12.28**	**-$ 2.36**	**-16.09%**
RTSR - Network	per kWh	$ 0.0071	158	$ 1.12	$ 0.0073	158	$ 1.15	$ 0.03	2.82%
RTSR - Line and	per kWh	$ 0.0049	158	$ 0.77	$ 0.0048	158	$ 0.76	-$ 0.02	-2.04%
Sub-Total C - Delivery				**$ 16.53**			**$ 14.19**	**-$ 2.34**	**-14.15%**
Wholesale Market Service	per kWh	$ 0.0052	158	$ 0.82	$ 0.0052	158	$ 0.82	$ -	0.00%
Rural and Remote Rate	per kWh	$ 0.0011	158	$ 0.17	$ 0.0011	158	$ 0.17	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	158	$ 1.11	$ 0.0070	158	$ 1.11	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0740	158	$ 11.69	$ 0.0740	158	$ 11.69	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0630	101	$ 6.37	$ 0.0630	101	$ 6.37	$ -	0.00%
TOU - Mid Peak		$ 0.0990	28	$ 2.82	$ 0.0990	28	$ 2.82	$ -	0.00%
TOU - On Peak		$ 0.1180	28	$ 3.36	$ 0.1180	28	$ 3.36	$ -	0.00%
Total Bill on RPP (before Taxes)				$ 30.57			$ 28.23	-$ 2.34	-7.65%
HST		13%		$ 3.97	13%		$ 3.67	-$ 0.30	-7.65%
Total Bill (including HST)				$ 34.55			$ 31.90	-$ 2.64	-7.65%
Ontario Clean Energy Benefit [1]				-$ 3.45			-$ 3.19	$ 0.26	-7.54%
Total Bill on RPP (including OCEB)				$ 31.10			$ 28.71	-$ 2.38	-7.66%
Total Bill on TOU (before Taxes)				$ 31.42			$ 29.08	-$ 2.34	-7.44%
HST		13%		$ 4.08	13%		$ 3.78	-$ 0.30	-7.44%
Total Bill (including HST)				$ 35.51			$ 32.86	-$ 2.64	-7.44%
Ontario Clean Energy Benefit [1]				-$ 3.55			-$ 3.29	$ 0.26	-7.32%
Total Bill on TOU (including OCEB)				$ 31.96			$ 29.57	-$ 2.38	-7.46%

Loss Factor (%) 5.3200% 5.3200%

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

Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Light**

Consumption 0.3 kW
120 kWh

◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct :

	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	$ 2.6400	1	$ 2.64	$ 2.5600	1	$ 2.56	-$ 0.08	-3.03%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Residual	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 5.9273	0.3	$ 1.78	$ 5.7365	0.3	$ 1.72	-$ 0.06	-3.22%
Smart Meter Disposition Rider			0.3	$ -		0.3	$ -	$ -	
LRAM & SSM Rate Rider			0.3	$ -		0.3	$ -	$ -	
Disposition-Residual Smart			0.3	$ -		0.3	$ -	$ -	
Sub-Total A				$ 4.42			$ 4.28	**-$ 0.14**	**-3.11%**
Deferral/Variance Account	per kW	-$ 0.5529	0.3	-$ 0.17	-$ 0.5529	0.3	-$ 0.17	$ -	0.00%
Deferral/Variance Account	per kW		0.3	$ -	$ 0.1009	0.3	$ 0.03	$ 0.03	
Low Voltage Service Charge			0.3	$ -		0.3	$ -	$ -	
Smart Meter Entity Charge						0.3	$ -	$ -	
Sub-Total B - Distribution				**$ 4.25**			**$ 4.15**	**-$ 0.11**	**-2.52%**
RTSR - Network	per kW	$ 2.2682	0	$ 0.72	$ 2.3404	0	$ 0.74	$ 0.02	3.18%
RTSR - Line and	per kW	$ 1.5674	0	$ 0.50	$ 1.5302	0	$ 0.48	-$ 0.01	-2.37%
Sub-Total C - Delivery				**$ 5.46**			**$ 5.37**	**-$ 0.10**	**-1.76%**
Wholesale Market Service	per kWh	$ 0.0052	126	$ 0.66	$ 0.0052	126	$ 0.66	$ -	0.00%
Rural and Remote Rate	per kWh	$ 0.0011	126	$ 0.14	$ 0.0011	126	$ 0.14	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	126	$ 0.88	$ 0.0070	126	$ 0.88	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0740	120	$ 8.88	$ 0.0740	120	$ 8.88	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0630	81	$ 5.10	$ 0.0630	81	$ 5.10	$ -	0.00%
TOU - Mid Peak		$ 0.0990	23	$ 2.25	$ 0.0990	23	$ 2.25	$ -	0.00%
TOU - On Peak		$ 0.1180	23	$ 2.68	$ 0.1180	23	$ 2.68	$ -	0.00%
Total Bill on RPP (before Taxes)				$ 16.28			$ 16.18	-$ 0.10	-0.59%
HST		13%		$ 2.12	13%		$ 2.10	-$ 0.01	-0.59%
Total Bill (including HST)				$ 18.39			$ 18.28	-$ 0.11	-0.59%
Ontario Clean Energy Benefit [1]				-$ 1.84			-$ 1.83	$ 0.01	-0.54%
Total Bill on RPP (including OCEB)				$ 16.55			$ 16.45	-$ 0.10	-0.59%
Total Bill on TOU (before Taxes)				$ 17.43			$ 17.33	-$ 0.10	-0.55%
HST		13%		$ 2.27	13%		$ 2.25	-$ 0.01	-0.55%
Total Bill (including HST)				$ 19.69			$ 19.58	-$ 0.11	-0.55%
Ontario Clean Energy Benefit [1]				-$ 1.97			-$ 1.96	$ 0.01	-0.51%
Total Bill on TOU (including OCEB)				$ 17.72			$ 17.62	-$ 0.10	-0.56%

Loss Factor (%) 5.3200% 5.3200%

Appendix J - Updated Customer Impact – Streetlighting (Updated)

Appendix 2-W
Bill Impacts

Customer Class: **Street Light**

Consumption 0.044 kW ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct
16 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 2.5100	1	$ 2.51	$ 1.8900	1	$ 1.89	-$ 0.62	-24.70%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Smart Meter Residual	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 10.5724	0.044	$ 0.47	$ 7.9541	0.044	$ 0.35	-$ 0.12	-24.77%
Smart Meter Disposition Rider			0.044	$ -		0.044	$ -	$ -	
LRAM & SSM Rate Rider			0.044	$ -		0.044	$ -	$ -	
Disposition-Residual Smart			0.044	$ -		0.044	$ -	$ -	
			0.044	$ -		0.044	$ -	$ -	
Sub-Total A				$ 2.98			$ 2.24	-$ 0.74	-24.71%
Deferral/Variance Account	per kW	-$ 0.5679	0.044	-$ 0.02	-$ 0.5679	0.044	-$ 0.02	$ -	0.00%
Deferral/Variance Account	per kW		0.044	$ -	$ 0.0998	0.044	$ 0.004	$ 0.00	
Deferral/Variance Account	per kW	-$ 0.1043	0.044	-$0.005	-$ 0.1043	0.044	-$ 0.005	$ -	0.00%
Deferral/Variance Account	per kW		0.044	$ -	$ 0.0995	0.044	$ 0.004	$ 0.00	
Low Voltage Service Charge			0.044	$ -		0.044	$ -	$ -	
Smart Meter Entity Charge						0.044	$ -	$ -	
Sub-Total B - Distribution				$ 2.95			$ 2.22	-$ 0.73	-24.66%
RTSR - Network	per kW	$ 2.2633	0	$ 0.10	$ 2.3353	0	$ 0.11	$ 0.00	3.18%
RTSR - Line and	per kW	$ 1.5640	0	$ 0.07	$ 1.5269	0	$ 0.07	-$ 0.00	-2.37%
Sub-Total C - Delivery				$ 3.12			$ 2.40	-$ 0.72	-23.21%
Wholesale Market Service	per kWh	$ 0.0052	17	$ 0.09	$ 0.0052	17	$ 0.09	$ -	0.00%
Rural and Remote Rate	per kWh	$ 0.0011	17	$ 0.02	$ 0.0011	17	$ 0.02	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	17	$ 0.12	$ 0.0070	17	$ 0.12	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0740	16	$ 1.18	$ 0.0740	16	$ 1.18	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0630	11	$ 0.68	$ 0.0630	11	$ 0.68	$ -	0.00%
TOU - Mid Peak		$ 0.0990	3	$ 0.30	$ 0.0990	3	$ 0.30	$ -	0.00%
TOU - On Peak		$ 0.1180	3	$ 0.36	$ 0.1180	3	$ 0.36	$ -	0.00%
Total Bill on RPP (before Taxes)				$ 4.78			$ 4.06	-$ 0.72	-15.16%
HST		13%		$ 0.62	13%		$ 0.53	-$ 0.09	-15.16%
Total Bill (including HST)				$ 5.40			$ 4.58	-$ 0.82	-15.16%
Ontario Clean Energy Benefit [1]				-$ 0.54			-$ 0.46	$ 0.08	-14.81%
Total Bill on RPP (including OCEB)				$ 4.86			$ 4.12	-$ 0.74	-15.20%
Total Bill on TOU (before Taxes)				$ 4.93			$ 4.21	-$ 0.72	-14.69%
HST		13%		$ 0.64	13%		$ 0.55	-$ 0.09	-14.69%
Total Bill (including HST)				$ 5.58			$ 4.76	-$ 0.82	-14.69%
Ontario Clean Energy Benefit [1]				-$ 0.56			-$ 0.48	$ 0.08	-14.29%
Total Bill on TOU (including OCEB)				$ 5.02			$ 4.28	-$ 0.74	-14.73%

Loss Factor (%) 5.3200% 5.3200%

Appendix K – Cost Allocation Sheet O1 (Updated)

	Total	1 Residential	2 GS <50	3 GS >50 to 4999 kW	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Distribution Revenue at Existing Rates	**$9,004,604**	$6,349,970	$1,039,230	$1,113,383	$182,911	$240,863	$31,798	$46,448
Miscellaneous Revenue (mi)	**$575,000**	$379,785	$68,092	$102,339	$0	$17,901	$4,315	$2,568
	Miscellaneous Revenue Input equals Output							
Total Revenue at Existing Rates	**$9,579,604**	**$6,729,756**	**$1,107,321**	**$1,215,723**	**$182,911**	**$258,764**	**$36,113**	**$49,016**
Factor required to recover deficiency (1 + D)	**0.9678**							
Distribution Revenue at Status Quo Rates	**$8,715,040**	$6,145,772	$1,005,811	$1,077,580	$177,029	$233,118	$30,776	$44,954
Miscellaneous Revenue (mi)	**$575,000**	$379,785	$68,092	$102,339	$0	$17,901	$4,315	$2,568
Total Revenue at Status Quo Rates	**$9,290,040**	**$6,525,558**	**$1,073,903**	**$1,179,919**	**$177,029**	**$251,019**	**$35,090**	**$47,522**
Expenses								
Distribution Costs (di)	**$2,590,800**	$1,576,473	$322,403	$603,006	$0	$69,819	$12,804	$6,295
Customer Related Costs (cu)	**$1,320,692**	$1,061,773	$144,115	$96,152	$0	$787	$3,165	$14,700
General and Administration (ad)	**$1,911,934**	$1,289,080	$228,092	$342,120	$0	$34,576	$7,815	$10,251
Depreciation and Amortization (dep)	**$874,188**	$495,784	$115,976	$227,692	$0	$27,049	$5,119	$2,567
PILs (INPUT)	**$50,631**	$28,885	$6,675	$13,020	$0	$1,598	$303	$151
Interest	**$654,849**	$373,589	$86,328	$168,399	$0	$20,666	$3,916	$1,951
Total Expenses	**$7,403,095**	**$4,825,584**	**$903,589**	**$1,450,389**	**$0**	**$154,496**	**$33,122**	**$35,915**
Direct Allocation	**$856,800**	**$585,553**	**$78,618**	**$91,085**	**$101,544**	**$0**	**$0**	**$0**
Allocated Net Income (NI)	**$1,030,145**	$587,693	$135,803	$264,908	$0	$32,510	$6,160	$3,070
Revenue Requirement (includes NI)	**$9,290,040**	$5,998,831	$1,118,010	$1,806,382	$101,544	$187,006	$39,282	$38,984
	Revenue Requirement Input equals Output							
Rate Base Calculation								
<u>Net Assets</u>								
Distribution Plant - Gross	**$45,459,898**	$25,573,053	$6,028,323	$12,006,358	$0	$1,443,880	$272,533	$135,750
General Plant - Gross	**$7,291,330**	$4,149,316	$959,841	$1,884,212	$0	$232,159	$43,958	$21,844
Accumulated Depreciation	**($27,568,543)**	($15,399,335)	($3,674,114)	($7,375,969)	$0	($872,663)	($164,401)	($82,062)
Capital Contribution	**($2,133,600)**	($1,177,756)	($276,052)	($583,722)	$0	($75,154)	($14,116)	($6,800)
Total Net Plant	**$23,049,085**	**$13,145,279**	**$3,037,998**	**$5,930,878**	**$0**	**$728,223**	**$137,975**	**$68,733**

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

		1	2	3	6	7	8	9
	Total	Residential	GS <50	GS >50 to 4999 kW	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Directly Allocated Net Fixed Assets	**$2,414,995**	**$1,872,459**	**$378,118**	**$127,268**	**$37,151**	**$0**	**$0**	**$0**
Cost of Power (COP)	**$43,394,903**	$16,731,313	$5,638,444	$14,566,360	$6,127,745	$131,047	$85,627	$114,368
OM&A Expenses	**$5,823,426**	$3,927,326	$694,610	$1,041,278	$0	$105,182	$23,784	$31,245
Directly Allocated Expenses	**$546,574**	$337,400	$32,343	$77,381	$99,450	$0	$0	$0
Subtotal	***$49,764,903***	***$20,996,039***	***$6,365,397***	***$15,685,019***	***$6,227,195***	***$236,229***	***$109,412***	***$145,613***
Working Capital	**$5,971,788**	**$2,519,525**	**$763,848**	**$1,882,202**	**$747,263**	**$28,347**	**$13,129**	**$17,474**
Total Rate Base	**$31,435,868**	**$17,537,262**	**$4,179,963**	**$7,940,347**	**$784,414**	**$756,570**	**$151,104**	**$86,207**
	Rate Base Input equals Output							
Equity Component of Rate Base	**$12,574,347**	**$7,014,905**	**$1,671,985**	**$3,176,139**	**$313,766**	**$302,628**	**$60,442**	**$34,483**
Net Income on Allocated Assets	**$1,030,145**	**$1,114,420**	**$91,696**	**($361,555)**	**$75,486**	**$96,523**	**$1,968**	**$11,607**
Net Income on Direct Allocation Assets	**$59,652**	**$46,251**	**$9,340**	**$3,144**	**$918**	**$0**	**$0**	**$0**
Net Income	**$1,089,797**	**$1,160,671**	**$101,035**	**($358,411)**	**$76,403**	**$96,523**	**$1,968**	**$11,607**
RATIOS ANALYSIS								
REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**108.78%**	**96.05%**	**65.32%**	**174.34%**	**134.23%**	**89.33%**	**121.90%**
EXISTING REVENUE MINUS ALLOCATED COSTS	**$289,564**	$730,925	($10,689)	($590,660)	$81,368	$71,758	($3,169)	$10,031
	Deficiency Input equals Output							
STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	$526,726	($44,108)	($626,463)	$75,486	$64,013	($4,192)	$8,538
RETURN ON EQUITY COMPONENT OF RATE BASE	8.67%	16.55%	6.04%	-11.28%	24.35%	31.89%	3.26%	33.66%

Appendix L– Revenue Requirement Work Form (Updated)

	Initial Application	(2)	Adjustments	Interrogatory Responses	(6)	Adjustments	Per Settlement Agreement
Rate Base							
Gross Fixed Assets (average)	$53,874,400		($33,245)	$ 53,841,155		$41,597	$53,882,752
Accumulated Depreciation (average)	($28,460,717)	(5)	$42,710	($28,418,007)		($666)	($28,418,673)
Allowance for Working Capital:							
Controllable Expenses	$6,636,967		$35,415	$ 6,672,382		($302,382)	$6,370,000
Cost of Power	$43,137,252			$ 43,137,252		$257,651	$43,394,903
Working Capital Rate (%)	13.00%	(9)		13.00%	(9)		12.00%
Utility Income							
Operating Revenues:							
Distribution Revenue at Current Rates	$8,970,789		$0	$8,970,789		$33,817	$9,004,606
Distribution Revenue at Proposed Rates	$9,158,591		$21,605	$9,180,196		($465,157)	$8,715,039
Other Revenue:							
Specific Service Charges	$150,385		$0	$150,385		$5,390	$155,775
Late Payment Charges	$70,849		$0	$70,849		$1,122	$71,971
Other Distribution Revenue	$236,908		$33	$236,941		$0	$236,941
Other Income and Deductions	$42,947		$18,932	$61,879		$48,434	$110,313
Total Revenue Offsets	$501,089	(7)	$18,965	$520,054		$54,946	$575,000
Operating Expenses:							
OM+A Expenses	$6,636,967		$35,415	$ 6,672,382		($302,382)	$6,370,000
Depreciation/Amortization	$1,081,619	(10)		$ 1,081,619		$3,563	$1,085,182
Property taxes							
Other expenses							
Taxes/PILs							
Taxable Income:							
Adjustments required to arrive at taxable income	($807,525)	(3)		($792,056)			($789,326)
Utility Income Taxes and Rates:							
Income taxes (not grossed up)	$50,245			$48,634			$43,045
Income taxes (grossed up)	$62,416			$60,415			$53,472
Federal tax (%)	15.00%			15.00%			15.00%
Provincial tax (%)	4.50%			4.50%			4.50%
Income Tax Credits	($19,100)			($19,100)			($22,000)
Capitalization/Cost of Capital							
Capital Structure:							
Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%
Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%
Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%
Prefered Shares Capitalization Ratio (%)							
	100.0%			100.0%			100.0%
Cost of Capital							
Long-term debt Cost Rate (%)	4.08%			4.03%			3.78%
Short-term debt Cost Rate (%)	2.06%			2.08%			2.08%
Common Equity Cost Rate (%)	9.12%			8.93%			8.93%
Prefered Shares Cost Rate (%)							
Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)	($35,324)	(11)	$35,324	$ -	(11)	($33,093)	($33,093)

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

Rate Base

Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Settlement Agreement
Gross Fixed Assets (average)	(3)	$53,874,400	($33,245)	$53,841,155	$41,597	$53,882,752
Accumulated Depreciation (average)	(3)	($28,460,717)	$42,710	($28,418,007)	($666)	($28,418,673)
Net Fixed Assets (average)	(3)	$25,413,683	$9,465	$25,423,148	$40,931	$25,464,079
Allowance for Working Capital	(1)	$6,470,648	$4,604	$6,475,252	($503,464)	$5,971,788
Total Rate Base		$31,884,331	$14,069	$31,898,400	($462,533)	$31,435,867

Working Capital

Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Settlement Agreement
Controllable Expenses		$6,636,967	$35,415	$6,672,382	($302,382)	$6,370,000
Cost of Power		$43,137,252	$ -	$43,137,252	$257,651	$43,394,903
Working Capital Base		$49,774,219	$35,415	$49,809,634	($44,731)	$49,764,903
Working Capital Rate %	(2)	13.00%	0.00%	13.00%	-1.00%	12.00%
Working Capital Allowance		$6,470,648	$4,604	$6,475,252	($503,464)	$5,971,788

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Settlement Agreement
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$9,158,591	$21,605	$9,180,196	($465,157)	$8,715,039
2	Other Revenue	(1)	$501,089	$18,965	$520,054	$54,946	$575,000
3	Total Operating Revenues		$9,659,680	$40,570	$9,700,250	($410,211)	$9,290,039
	Operating Expenses:						
4	OM+A Expenses		$6,636,967	$35,415	$6,672,382	($302,382)	$6,370,000
5	Depreciation/Amortization		$1,081,619	$ -	$1,081,619	$3,563	$1,085,182
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$7,718,586	$35,415	$7,754,001	($298,819)	$7,455,182
10	Deemed Interest Expense		$754,766	($8,343)	$746,423	($54,833)	$691,589
11	Total Expenses (lines 9 to 10)		$8,473,352	$27,072	$8,500,424	($353,652)	$8,146,771
12	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS		($35,324)	$35,324	$ -	($33,093)	($33,093)
13	**Utility income before income taxes**		$1,221,652	($21,826)	$1,199,826	($23,466)	$1,176,361
14	Income taxes (grossed-up)		$62,416	($2,001)	$60,415	($6,943)	$53,472
15	**Utility net income**		$1,159,236	($19,824)	$1,139,412	($16,523)	$1,122,889

Other Revenues / Revenue Offsets

Other Revenues / Offsets

Line No.	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Settlement Agreement
(1)	Specific Service Charges	$150,385	$ -	$150,385	$5,390	$155,775
	Late Payment Charges	$70,849	$ -	$70,849	$1,122	$71,971
	Other Distribution Revenue	$236,908	$33	$236,941	$ -	$236,941
	Other Income and Deductions	$42,947	$18,932	$61,879	$48,434	$110,313
	Total Revenue Offsets	$501,089	$18,965	$520,054	$54,946	$575,000

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Settlement Agreement
	Determination of Taxable Income			
1	Utility net income before taxes	$1,163,140	$1,139,411	$1,122,889
2	Adjustments required to arrive at taxable utility income	($807,525)	($792,056)	($789,326)
3	Taxable income	$355,615	$347,355	$333,563
	Calculation of Utility income Taxes			
4	Income taxes	$50,245	$48,634	$43,045
6	Total taxes	$50,245	$48,634	$43,045
7	Gross-up of Income Taxes	$12,171	$11,781	$10,427
8	Grossed-up Income Taxes	$62,416	$60,415	$53,472
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$62,416	$60,415	$53,472
10	Other tax Credits	($19,100)	($19,100)	($22,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	4.50%	4.50%	4.50%
13	Total tax rate (%)	19.50%	19.50%	19.50%

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

Capitalization/ Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$17,855,226	4.08%	$728,493
2	Short-term Debt	4.00%	$1,275,373	2.06%	$26,273
3	**Total Debt**	60.00%	$19,130,599	3.95%	$754,766
	Equity				
4	Common Equity	40.00%	$12,753,733	9.12%	$1,163,140
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$12,753,733	9.12%	$1,163,140
7	**Total**	100.00%	$31,884,331	6.02%	$1,917,906
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$17,863,104	4.03%	$719,883
2	Short-term Debt	4.00%	$1,275,936	2.08%	$26,539
3	**Total Debt**	60.00%	$19,139,040	3.90%	$746,423
	Equity				
4	Common Equity	40.00%	$12,759,360	8.93%	$1,139,411
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$12,759,360	8.93%	$1,139,411
7	**Total**	100.00%	$31,898,400	5.91%	$1,885,833
		Per Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$17,604,086	3.78%	$665,434
9	Short-term Debt	4.00%	$1,257,435	2.08%	$26,155
10	**Total Debt**	60.00%	$18,861,520	3.67%	$691,589
	Equity				
11	Common Equity	40.00%	$12,574,347	8.93%	$1,122,889
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$12,574,347	8.93%	$1,122,889
14	Total	100.00%	$31,435,867	5.77%	$1,814,478

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

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 Settlement Agreement – At Current Approved Rates	Per Settlement Agreement – At Proposed Rates
1	Revenue Deficiency from Below		$191,706		$209,407		($289,567)
2	Distribution Revenue	$8,970,789	$8,966,885	$8,970,789	$8,970,789	$9,004,606	$9,004,606
3	Other Operating Revenue Offsets - net	$501,089	$501,089	$520,054	$520,054	$575,000	$575,000
4	**Total Revenue**	$9,471,878	$9,659,680	$9,490,843	$9,700,250	$9,579,606	$9,290,039
5	Operating Expenses	$7,718,586	$7,718,586	$7,754,001	$7,754,001	$7,455,182	$7,455,182
6	Deemed Interest Expense	$754,766	$754,766	$746,423	$746,423	$691,589	$691,589
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($35,324) (2)	($35,324)	$ - (2)	$ -	($33,093) (2)	($33,093)
8	**Total Cost and Expenses**	$8,438,028	$8,438,028	$8,500,424	$8,500,424	$8,113,678	$8,113,678
9	**Utility Income Before Income Taxes**	$1,033,850	$1,221,652	$990,419	$1,199,826	$1,465,928	$1,176,361
10	Tax Adjustments to Accounting Income per 2013 PILs model	($807,525)	($807,525)	($792,056)	($792,056)	($789,326)	($789,326)
11	**Taxable Income**	$226,325	$414,127	$198,363	$407,770	$676,602	$387,035
12	Income Tax Rate	19.50%	19.50%	19.50%	19.50%	19.50%	19.50%
13	**Income Tax on Taxable Income**	$44,133	$80,755	$38,681	$79,515	$131,937	$75,472
14	**Income Tax Credits**	($19,100)	($19,100)	($19,100)	($19,100)	($22,000)	($22,000)
15	**Utility Net Income**	$1,008,817	$1,159,236	$970,839	$1,139,412	$1,355,991	$1,122,889
16	**Utility Rate Base**	$31,884,331	$31,884,331	$31,898,400	$31,898,400	$31,435,867	$31,435,867
17	Deemed Equity Portion of Rate Base	$12,753,733	$12,753,733	$12,759,360	$12,759,360	$12,574,347	$12,574,347
18	Income/(Equity Portion of Rate Base)	7.91%	9.09%	7.61%	8.93%	10.78%	8.93%
19	Target Return - Equity on Rate Base	9.12%	9.12%	8.93%	8.93%	8.93%	8.93%
20	Deficiency/Sufficiency in Return on Equity	-1.21%	-0.03%	-1.32%	0.00%	1.85%	0.00%
21	Indicated Rate of Return	5.53%	6.00%	5.38%	5.91%	6.51%	5.77%
22	Requested Rate of Return on Rate Base	6.02%	6.02%	5.91%	5.91%	5.77%	5.77%
23	Deficiency/Sufficiency in Rate of Return	-0.48%	-0.01%	-0.53%	0.00%	0.74%	0.00%
24	Target Return on Equity	$1,163,140	$1,163,140	$1,139,411	$1,139,411	$1,122,889	$1,122,889
25	Revenue Deficiency/(Sufficiency)	$154,324	($3,904)	$168,572	$1	($233,101)	($0)
26	**Gross Revenue Deficiency/(Sufficiency)**	$191,706 (1)		$209,407 (1)		($289,567) (1)	

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

Revenue Requirement:

Line No.	Particulars	Application		Interrogatory Responses		Per Settlement Agreement
1	OM&A Expenses	$6,636,967		$6,672,382		$6,370,000
2	Amortization/Depreciation	$1,081,619		$1,081,619		$1,085,182
3	Property Taxes	$ -				
5	Income Taxes (Grossed up)	$62,416		$60,415		$53,472
6	Other Expenses	$ -				
7	Return					
	Deemed Interest Expense	$754,766		$746,423		$691,589
	Return on Deemed Equity	$1,163,140		$1,139,411		$1,122,889
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($35,324)		$ -		($33,093)
8	**Service Revenue Requirement (before Revenues)**	$9,663,584		$9,700,249		$9,290,039
9	Revenue Offsets	$501,089		$520,054		$575,000
10	**Base Revenue Requirement (excluding TranformerOwership Allowance credit adjustment)**	$9,162,495		$9,180,195		$8,715,039
11	Distribution revenue	$9,158,591		$9,180,196		$8,715,039
12	Other revenue	$501,089		$520,054		$575,000
13	**Total revenue**	$9,659,680		$9,700,250		$9,290,039
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($3,904)	(1)	$1	(1)	($0)

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	$ 3,839,581	$ 2,162,123		$ 6,001,704	$ 6,007,416
GS < 50 kW	$ 566,396	$ 449,233	($11,559)	$ 1,004,070	$ 1,005,811
GS >50 to 4999 kW	$ 543,382	$ 928,031	($128,634)	$ 1,342,779	$ 1,342,766
Large Use	$ 92,112	$ 134,177	($118,173)	$ 108,116	$ 108,118
Sentinel Lights	$ 17,599	$ 13,177		$ 30,776	$ 30,776
Street Lighting	$ 152,960	$ 28,253		$ 181,213	$ 181,212
Unmetered and Scattered	$ 30,649	$ 8,334		$ 38,983	$ 38,941
Total	**$ 5,242,680**	**$ 3,723,327**	**($258,366)**	**$ 8,707,641**	**$ 8,715,039**

Difference Due to Rate Rounding

$ 7,398

APPENDIX B

TO DECISION AND ORDER
EB-2012-0173

Welland Hydro-Electric System Corp.
Draft Tariff of Rates and Charges

DATED: March 21, 2013

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0173

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached or semi-detached units, as defined in the local zoning by-law. 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	$	15.66
Rate Rider for Stranded meters – effective until April 30, 2017	$	0.45
Distribution Volumetric Rate	$/kWh	0.0133
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) - effective until April 30, 2014 – applicable only to Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Disposition of Deferral/ Variance Accounts (2012) – effective until April 30, 2014	$/kWh	(0.0016)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015 – applicable only to Non-RPP Customers	$/kWh	0.0003
Rate Rider for Disposition of Deferral/ Variance Accounts (2012) – effective until April 30, 2015	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0083
Retail Transmission Rate – Line and Transformation Connection 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

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0173

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to commercial buildings taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Commercial buildings are defined as buildings, which are used for purposes other than resident dwellings. 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	$	27.83
Rate Rider for Stranded Meters – effective until April 30, 2017	$	0.48
Distribution Volumetric Rate	$/kWh	0.0082
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014		
- applicable only to Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Disposition of Deferral/ Variance Accounts (2012) – effective until April 30, 2014	$/kWh	(0.0015)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) – effective until April 30, 2015		
- applicable only to Non-RPP Customers	$/kWh	0.0003
Rate Rider for Disposition of Deferral/ Variance Accounts (2013) – effective until April 30, 2015	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0073
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

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

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0173

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to commercial buildings whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Commercial buildings are defined as buildings, which are used for purposes other than resident dwellings. 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	$	267.94
Distribution Volumetric Rate	$/kW	2.3435
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) - effective until April 30, 2014 – applicable only to Non-RPP Customers	$/kW	(0.0995)
Rate Rider for Disposition of Deferral/ Variance Accounts (2012) – effective until April 30, 2014	$/kW	(0.5226)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015 – applicable only to Non-RPP Customers	$/kW	0.0992
Rate Rider for Disposition of Deferral/ Variance Accounts (2013) – effective until April 30, 2015	$/kW	0.0995
Retail Transmission Rate – Network Service Rate	$/kW	2.5129
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6428
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.4926
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9679

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

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0173

LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater 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	$	7,676.01
Distribution Volumetric Rate	$/kW	0.7948
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 – applicable only to Non-RPP Customers	$/kW	(0.1010)
Rate Rider for Disposition of Deferral/ Variance Accounts (2012) – effective until April 30, 2014	$/kW	(0.5277)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) – effective until April 30, 2015 – applicable only to Non-RPP Customers	$/kW	0.0979
Rate Rider for Disposition of Deferral/ Variance Accounts (2013) – effective until April 30, 2015	$/kW	0.0982
Retail Transmission Rate – Network Service Rate	$/kW	1.8264
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.1853

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

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0173

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Unmetered or flat connections are permitted with the approval of Welland Hydro-Electric System Corp. Engineering Department. Flat rate connects may include, but are not limited to, Traffic Lights, Street Lights, Bus Shelters, and Signs. Energy consumption is determined by information provided by the customer and/or load measurement taken by Welland Hydro-Electric System Corp. following connection of the flat service. 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)	$	11.35
Distribution Volumetric Rate	$/kWh	0.0075
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 – applicable only to Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Disposition of Deferral/ Variance Accounts (2012) – effective until April 30, 2014	$/kWh	(0.0016)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) – effective until April 30, 2015 – applicable only to Non-RPP Customers	$/kWh	0.0003
Rate Rider for Disposition of Deferral/ Variance Accounts (2013) – effective until April 30, 2015	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0073
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

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

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0173

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting not classified as unmetered or street lighting. The consumption for the customer will be based on the calculated connected load times a twelve hour day times the applicable billing period. 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)	$	2.56
Distribution Volumetric Rate	$/kW	5.7365
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 – applicable only to Non-RPP Customers	$/kW	(0.1026)
Rate Rider for Disposition of Deferral/ Variance Accounts (2012) – effective until April 30, 2014	$/kW	(0.5529)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) – effective until April 30, 2015 – applicable only to Non-RPP Customers	$/kW	0.1005
Rate Rider for Disposition of Deferral/ Variance Accounts (2013) – effective until April 30, 2015	$/kW	0.1009
Retail Transmission Rate – Network Service Rate	$/kW	2.3404
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5302

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

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0173

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to the Street Lighting system owned by the City of Welland. Welland Hydro-Electric System Corp. provides new installations and maintenance of the street lighting system, as required by the City of Welland. 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)	$	1.89
Distribution Volumetric Rate	$/kW	7.9541
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 – applicable only to Non-RPP Customers	$/kW	(0.1043)
Rate Rider for Disposition of Deferral/ Variance Accounts (2012) – effective until April 30, 2014	$/kW	(0.5679)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) – effective until April 30, 2015 – applicable only to Non-RPP Customers	$/kW	0.0995
Rate Rider for Disposition of Deferral/ Variance Accounts (2013) – effective until April 30, 2015	$/kW	0.0998
Retail Transmission Rate – Network Service Rate	$/kW	2.3353
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5269

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

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0173

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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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.40

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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EB-2012-0173

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.70)
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		
Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Account history	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
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
Disconnect / Reconnect at meter - during regular hours	$	65.00
Install / Remove load control device - during regular hours	$	65.00
Disconnect / Reconnect at meter - after regular hours	$	185.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Meter upgrade requested by customer plus installation – per month plus installation on a time and material basis.	$	10.00

Welland Hydro-Electric System Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0173

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.

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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	1.0532
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0427
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

TAB B

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

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

BY E-MAIL

June 3, 2015

TO: All Licensed Electricity Distributors
All Other Interested Parties

RE: Allowance for Working Capital for Electricity Distribution Rate Applications

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This letter provides an update to the OEB's policy for the calculation of the allowance for working capital for electricity rate applications.

Effective immediately, the OEB is a adopting a new default value of 7.5% of the sum of the cost of power and operating, maintenance and administration (OM&A) costs. As in the past, distributors who do not wish to use the default value can request approval for a distributor-specific working capital allowance supported by the appropriate evidence from a lead-lag study or equivalent analysis.

The OEB is also of the view that the use of the default value should only be implemented during a cost of service application, with a few exceptions as discussed further in this letter. For a custom incentive rate-setting (Custom IR) application distributors are expected to file robust evidence of costs and revenues, and the review of these applications is expected to require considerable resources from both the OEB and the distributor. It is therefore reasonable to expect distributors choosing this option to file evidence in support of their requested working capital allowance, rather than the use of a default value.

Background

Section 2.5.1.3 of the *Filing Requirements for Electricity Distribution Rate Applications* for the 2015 rate year, issued on July 18, 2014, provided for two approaches that an applicant could take for the calculation of the allowance for working capital: 1) the 13% allowance approach; or 2) the filing of a lead-lag study. The second of these approaches has been optional for all utilities that have not been directed to conduct a lead-lag study by the OEB.

The OEB has been using a default value approach to calculating working capital allowance since the 1st Generation Rate Handbook was issued in 2000. At that time, the default value was established as 15% of the total of the cost of power and OM&A expenses. By letter dated April 12, 2012, the OEB reduced the default value to 13% after lead lag studies routinely produced results of less than 15%.

It has become apparent to the OEB that average working capital requirements have been lowered as a result of a number of technical changes that reduce the actual time between service provision and payment. These include: 1) the substantial completion of the smart meter rollout and advanced metering infrastructure, which reduces aggregate meter reading time ; 2) wider adoption of monthly billing, resulting in a shorter period from service to payment; 3) customer information system updates, which reduce time required to calculate customer bills; and 4) general process improvements. The adoption of mandatory monthly billing for all distributors by December 31, 2016, should result in further downward pressure on working capital requirements. Considering all of these current and forthcoming changes, the OEB determined that a review of its approach to working capital allowance was warranted.

Working Capital Allowance for the 2016 Rate Year

The OEB continues to believe that a default value approach is an efficient alternative for setting the working capital allowance. However, a default value should not result in a working capital allowance that is reasonably expected to be higher than what would result from the use of the more accurate and detailed approach of completing a lead-lag study. The OEB also considers that maintaining a default value that is too high does not incent a utility to study its business processes and improve productivity, which would be at odds with the principles embedded in its Renewed Regulatory Framework.

Therefore, the OEB has determined that, effective immediately, the default value for working capital allowance for electricity distributors will be 7.5% of the sum of cost of power and OM&A. The default value will be reflected in the 2015 edition of the *Filing Requirements for Electricity Distribution Rate Applications* for 2016 Rate Applications.

This determination is based on a review of a range of results for lead-lag studies filed by distributors, which showed that working capital allowance results have been declining. For the applications filed for 2015 rates, the results have ranged from 7.4% to 12.7% of the sum of the cost of power and OM&A. Given that many of the financial settlement processes are common between distributors, and all distributors will be required to bill on a monthly basis by the end of 2016, the OEB is adopting a new default of 7.5%. In the OEB's judgment, this default reasonably reflects not only the range of inputs that distributors have reported to the OEB, but also the forthcoming policy changes regarding mandatory monthly billing. The adoption of this new lower default value reflects a goal that all distributors strive for best practices in their administrative processes while supporting a distributor's basic cash flow requirements.

Analysis

To support the OEB's consideration of a new default value, OEB staff reviewed eight lead-lag studies filed with the OEB since 2010 and evaluated the key factors in those studies. OEB staff also considered elements external to a distributor's own operations, such as the cost of power settlement process, and factored in the billing standards identified in the Distribution System Code, such as the identification of a minimum payment period of 16 days from the date on which a bill was issued to a customer. A summary of the results of the OEB staff analysis is attached to this letter as Appendix A. The analysis, which selected a combination of median inputs as well as values that reflect OEB policy, resulted in a calculation of a default value for the working capital allowance of 7.5%.

The OEB also commissioned a jurisdictional review to determine if there are other approaches to the funding of working capital requirements. This review is attached as Appendix B. All jurisdictions reviewed generally included an allowance for working capital to be treated as an asset, attracting a return. On this basis, the OEB does not believe that a fundamental change to its approach to funding working capital requirements is warranted.

The OEB will continue to monitor factors such as the elimination of the debt retirement charge for residential customers, the end of the Ontario Clean Energy Benefit and implementation of the Ontario Electricity Support Program as of January 1, 2016 to determine if they have an effect on cash flow.

Implementation

The new policy is effective immediately. Changes to working capital allowance costs will be implemented only in cost of service and Custom IR applications unless otherwise determined by the OEB in a prior decision. This will allow for all of a distributor's costs to be considered at the same time. The OEB adopted the same approach when it amended its cost of capital policy in 2009.

The OEB recognizes that a specific utility's own systems, processes and customer mix will influence its working capital needs. While there are similar settlement processes, lead-lag results are not directly interchangeable among utilities. Distributors can use a lead-lag study or equivalent analysis to support a request for a distributor-specific working capital allowance.

While the use of the default value will no longer be applicable to Custom IR applications, given the timing of this new policy, distributors that have filed a Custom IR application for rates effective January 1, 2016 may use the 7.5% default value to calculate their working capital allowance rather than file a lead-lag study as part of their application.

For questions relating to this amendment please contact IndustryRelations@ontarioenergyboard.ca.

Sincerely,

Original Signed By

Kirsten Walli
Board Secretary

Appendix A

Allowance for Working Capital for Electricity Distributors

June 3, 2015

Appendix A

The following is a summary of the results of OEB staff analysis, based on its review of eight lead-lag studies provided to the OEB since 2010.

		Revenue Periods (Lag Days)					Expenses (Lead Days)				
Elements of Working Capital		Service	Billing	Collection	Processing	Total	Lead Days	Net Days	Weighting Factor	Weighted Lead/Lag Days	WCF***
1	Cost of Power	15.2	17.5	22.0	1.4	56.1	(32.7)	23.40	82.8%	19.38	
2	Payroll etc.*	15.2	17.5	22.0	1.4	56.1	(9.4)	46.70	5.2%	2.43	
3	Other OM&A	15.2	17.5	22.0	1.4	56.1	(7.8)	48.30	2.8%	1.35	
4	PiLs, etc.**	15.2	17.5	22.0	1.4	56.1	(29.1)	27.00	9.2%	2.48	
5	Sub Total								100.0%	25.64	7.0%
6	HST								0.5%		0.5%
7	Total										7.5%

Element	**Determination**
Service Period	Reflects mandatory monthly billing: 365.25÷12÷2=15.22 days
Billing Period	Median based on observed range of 13.0 days to 19.0 days
Collection Period	Minimum payment period plus allowances for payments by mail as specified in s. 2.6 of the Distribution System Code. Observed sample range is 21.8 days to 29.1 days
Processing Period	Median based on observed range of 1.0 to 1.5 days
Lead Days	Median based on observed results for each expense element
HST	Median based on observed range of 0.3% to 1.4%
Weighting Factor	Reflects proportions of cost of power and OM&A expense categories based on median values from sample studies

*Payroll includes benefits. **PiLs also includes interest and debt repayment costs.
******* Working Capital Factor calculation: Weighted Lead/Lag Days ÷ 365.25 days per year + HST factor.

Appendix B

Allowance for Working Capital for Electricity Distributors

June 3, 2015

cutting through complexity

New Policy Options for the Funding of Capital Investments: EB-2014-0219 – Treatment of Working Capital Excerpt

May 12, 2015

prepared for Ontario Energy Board

Draft

Contents

1 Introduction

The Ontario Energy Board (the "Board" or "OEB") has retained KPMG LLP ("KPMG") to provide regulatory advisory services in connection with the Board's June 20, 2014 consultation on New Policy Options for the Funding of Capital Investments EB-2014-0219. KPMG is to review the details of the half year rule, the make-up of the Incremental Capital Module ("ICM") Materiality Threshold Formula ("Materiality Threshold Formula") and how working capital is funded through distribution rates in other jurisdictions.

Specifically, KPMG has been engaged to conduct jurisdictional reviews:

- To determine whether rules or approaches, similar to the "half-year rule" for the determination of the return of and on capital in the first calendar year when capital assets enter service, are in use. If not, set out the approach used, including the logic supporting the approach and the mechanical operation of the approach. If so, set out the logic supporting the use of such an approach and mechanical operation of the approach. Analyze the extent to which the rule or approach is compensatory with respect to recovery of capital costs in rates (in cost of service and incentive rate ("IR")-based rate adjustment mechanisms) and discuss the consequences of the rule or approach on process/regulatory efficiency.

- To identify incentive ratemaking approaches, with a focus on:

    - Identifying the mechanisms used to fund new capital investments over the IR period; and

    - Explaining how rates are adjusted to reflect new capital expenditures over the IR period, if applicable.

- To determine how working capital is treated for the purpose of setting rates.

KPMG has also been asked to review the interaction and effect of key variables in the Materiality Threshold Formula, with a focus on:

- Setting out the theoretical and practical driver for the use of the growth factor and dead band variable in the calculation of the Materiality Threshold Formula;

- Determining whether there is a more accurate method of estimating or calculating the growth factor in the Materiality Threshold Formula; and

- Determining whether the transition to International Financial Reporting Standard ("IFRS") and use of Total Factor Productivity ("TFP") to inform the IR rate adjustment mechanism affect the appropriate dead band variable to be used.

1.1 Jurisdictional Reviews

KPMG considered the regulatory practice relating to the half-year rule, working capital and incentive ratemaking regimes in the following jurisdictions:

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Canada: Ontario electricity distribution, Ontario electricity transmission, Ontario natural gas distribution (Enbridge Gas Distribution Inc. and Union Gas Limited), Alberta, Nova Scotia (Nova Scotia Power Inc.), British Columbia (FortisBC Inc.), Newfoundland (Newfoundland Power Inc.), and Québec (Gaz Métro L.P.).

United States: Alabama, California, Georgia, Louisiana, Maryland, Massachusetts, Mississippi, New York, and Pennsylvania.

United Kingdom: Ofgem (RIIO for Electricity Transmission).

The full review for the target entities in each named jurisdiction are set out in the attached Appendices: Appendix 1: Canada; Appendix 2: United States; and Appendix: 3 United Kingdom.

1.2 Excerpt Draft Report on Working Capital Allowance

KPMG has also been asked to prepare Draft Report, which reflects our work as set out above. The Draft Report will also include options and recommendations with respect to changes that may be required to:

- The half year rule during the IR period;
- Use of the growth factor and dead band variable used in the Materiality Threshold Formula of the ICM; and
- Treatment of working capital allowance under cost of service and/or alternative forms of ratemaking.

On May 11, 2015, the OEB requested that KPMG also produce a stand-alone document that would include our work relating to the treatment of working capital allowance under cost of service and/or alternative forms of ratemaking.

This Excerpt Draft Report is designed to satisfy this latter request.

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2 Treatment of Working Capital

The treatment of working capital is generally consistent in all of the Canadian and U.S. jurisdictions studied. In the North American jurisdictions reviewed, working capital is generally included in rate base and as such, attracts the weighted average cost of capital permitted by the relevant regulator and taxes/PILs. Working capital balances are not depreciated; however, in some jurisdictions, working capital may include regulatory deferrals and other amounts that may be subject to amortization. The related amortization expense is generally determined in a manner that is separate from the process used to determine depreciation expense and/or cumulative depreciation for assets in rate base.

The treatment of working capital pursuant to the RIIO framework in the U.K. is more unique, reflecting the distinct approach adopted for ratemaking purposes. In the RIIO model, as set out in Appendix 3, working capital is included in the "slow money" calculation that is used to inform the determination of real asset value, or RAV, that attracts a return of and on capital.

Table1 highlights the treatment of working capital in each jurisdiction reviewed, in cost of service and PBR.

Table 1. Treatment of Working Capital in Rate Setting Processes

Jurisdiction	Cost of Service	Incentive Regulation
Ontario Electricity Distribution	Working capital required for operations is included in the determination of rate base in the COS year.	Working capital is not specifically addressed in an IR application. It is embedded in base rates, as per the rebasing year COS proceeding.
Ontario Electricity Transmission	Working capital required for operations is included in the determination of rate base in the COS year.	N/A (No incentive regulation)
Enbridge Gas Distribution	Working capital required for operations is included in the determination of rate base in the COS year.	In Enbridge's 5-Year Custom IR Plan, rate base, including the provision for working capital, is effectively rebased annually.
Union Gas	Working capital required for operations is included in the determination of rate base in the COS year.	Working capital is not specifically addressed in an IR application. It is embedded in base rates, as per the rebasing year COS proceeding.
Alberta Natural Gas And Electricity Distribution	Working capital required for operations is included in in the determination of rate base in the COS year.	An allowance for working capital is not included in the revenue requirement calculation for the K factor rate adjustment.
Nova Scotia Power	Cash working capital is included in the calculation of average rate base for the test year.	N/A (No incentive regulation)

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Jurisdiction	Cost of Service	Incentive Regulation
FortisBC	Allowance for working capital is included in the calculation of rate base.	In the Targeted PBR regime in use by FortisBC, rate base, including WC, is calculated annually.
Newfoundland Power	Cash working capital is included in the calculation of rate base in the COS test year.	N/A (No incentive regulation)
Gaz Métro	Working capital is included in the calculation of rate base in the COS test year.	N/A (No incentive regulation)
Alabama Power Company	Non-cash working capital is included in the calculation of rate base.	N/A (No incentive regulation)
Southern California Edison	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)
Georgia Power	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)
Entergy Louisiana	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)
Maryland Public Service Commission	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)
Massachusetts Electric	Non-cash working capital is included in the calculation of rate base.	N/A (No incentive regulation)
Mississippi Power	Non-cash working capital is included in the calculation of rate base.	N/A (No incentive regulation)
Consolidated Edison Company of New York	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)
PECO Energy Company	Both cash and non-cash working capital are included in the calculation of rate base.	N/A (No incentive regulation)
Ofgem	Working Capital included in rate base through "slow money" calculation.	RIIO is a comprehensive, multi-year rate setting regime that is a hybrid of cost of service and IR rate regimes.

Source: KPMG Analysis

3 Recommendation

KPMG has been asked to include options and recommendations with respect to changes that may be required to:

- The half year rule during the IR period;
- Use of the growth factor and dead band variable used in the Materiality Threshold Formula of the ICM; and
- Treatment of working capital allowance under cost of service and/or alternative forms of ratemaking.

Our thoughts on those issues relating to: (i) the half year rule during the IR period and (ii) use of the growth factor and dead band variable used in the Materiality Threshold Formula of the ICM, are set out in our full Draft Report. For the purpose of this Excerpt Draft Report, we include only our thoughts relating to the treatment of working capital allowance under cost of service and/or alternative forms of ratemaking.

Our thoughts are as follows:

1. **Treatment of Working Capital:** Based on the jurisdictional review presented herein, we understand that working capital is reflected in rate base in all of the jurisdictions reviewed. As such, it attracts the weighted average cost of capital allowed by the regulator in each jurisdiction and these costs are reflected in both cost of service rates and rates in subsequent IR years. On this basis, it is not clear to us that there is a reasonable basis upon which an alternative treatment would be warranted.

KPMG thanks the Board for the opportunity to complete this mandate and would be pleased to discuss this Draft Excerpt Report, at the Board's convenience.

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4 Bibliography

For a complete list of the resources used by KPMG to inform the jurisdictional analysis set out in this Excerpt Draft Report, please see the bibliography in the Draft Report prepared by KPMG entitled “New Policy Options for the Funding of Capital Investments: EB-2014-0219” and dated May 12, 2015.

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Appendix 1 Canada Jurisdictional Review

Ontario Electricity Distribution

	Description
Treatment of Working Capital	**Working Capital** is the amount of funds required to finance the day-to-day operations of a regulated utility and is included as part of rate base for ratemaking purposes. It is comprised of two amounts: (1) cash working capital; and (2) mid-year materials and supplies inventory. The determination of cash working capital relies on a lead-lag study. In Chapter 2 (Cost of Service) of the Filing Requirements for Electricity Distribution Rate Applications - 2014 Edition for 2015 Rates Applications, the Board indicates that the applicant may take one of two approaches for the calculation of its allowance for working capital: (1) the 13% allowance approach; or (2) the filing of a lead/lag study. The only exception is if the application has been previously directed by the Board to undertake a lead/lag study on which its current working capital allowance is based.
	13% Allowance Approach: Cash working capital can be calculated to be 13% of the sum of the retail cost of power and controllable expenses (i.e., OM&A, capital and income taxes).
	Lead/Lag Study: A lead/lag study analysis for two time periods; namely: (1) the time between the date customers receive service and the date that the customers' payments are available to the distributor (the lag); and (2) the time between the date when the distributor receives goods and services from its supplies and vendors and the date that it pays for them (the lead). The leads and lags are measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e., lag minus lead) days is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations.
	Included In Rate Base: Regardless of the method chosen to calculate cash working capital, the amount of working capital required for operations is included in the applicant's rate base determination. Rate base is the sum of: (1) **Working Capital Allowance** - as described previously; and (2) **Average Net Fixed Assets** - the average gross fixed assets (GFA) minus average accumulated depreciation (AD). Average GFA is the average of the opening GFA (beginning of the test year) and closing GFA (end of the test year). Average AD is equal to the sum of opening AD and closing AD, divided by 2. Closing AD is equal to: (1) opening AD; plus (2) depreciation associated with opening GFA; plus (2) depreciation associated with in-service capital additions divided by 2 (half-year application); less (3) depreciation associated with disposals; less (4) depreciation associated with retirements. Closing GFA is equal to: (1) opening GFA; plus (2) in-service capital additions; and

	Description
	less (3) capital retirements. Each of capital additions and capital retirements are "rebased" to capture any adjustments between the closing balance at the end of the prior year (t-1) and the beginning of the test year and any amount that will be closed to rate base during the test year.
	ICM Calculation: Working capital is not specifically addressed in an IR application. It is embedded in base rates, as per the cost of service proceeding. In the context of the ICM/ACM, working capital is included in the rate base used in the Threshold Test. The working capital percent metric is the Board-approved WCA from the distributor's last rebasing application. The Threshold Test is set out in Sheet E2.1 Threshold Test of the Incremental Capital Model for 2015 Filers on the Board's website. The calculation of Incremental Capital Adjustment found on Sheet E4.1 IncrementalCapitalAdjust in the same workbook does not include a provision for incremental working capital in the calculation. The additional revenue requirement associated with the ICM reflects: (i) return on rate base; (ii) amortization expense; (iii) grossed up PIL's; and (iv) Ontario capital tax.

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	Description
Treatment of Working Capital	**Working Capital** is the amount of funds required to finance the day-to-day operations of a regulated utility and is included as part of rate base for ratemaking purposes. It is comprised of two amounts: (1) cash working capital; and (2) mid-year materials and supplies inventory. The determination of cash working capital relies on a lead-lag study.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: A lead/lag study analysis for two time periods is required; namely: (1) the time between the date customers receive service and the date that the customers' payments are available to the transmitter (the lag); and (2) the time between the date when the transmitter receives goods and services from its suppliers and vendors and the date that it pays for them (the lead). Leads and lags are measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e., lag minus lead) days is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations.
	Included in Rate Base: The amount of working capital required for operations is included in the applicant's rate base determination.
	ICM Calculation: Not applicable.

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	Description
Treatment of Working Capital	**Working Capital** is the amount of funds required to finance the day-to-day operations of a regulated utility and is included as part of rate base for ratemaking purposes. The determination of working capital relies on a lead-lag study to determine working cash allowance. Working cash allowance is one of a number of components that comprise the Allowance for Working Capital that is included in rate base. Other components include: (1) accounts receivable rebillable projects; (2) materials and supplies; (3) mortgage receivable; (4) customer security deposits; (5) prepaid expenses; and (6) gas in storage.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: A lead/lag study is conducted to determine working cash allowance. The study considers the time between when the utility has received a good or service and when payment is made, known as the Expense Lead and the time between when the utility has provided a good or service and when it receives payment, known as the Revenue Lag. The difference between the Expense Leads and the total Revenue Lags is the Net Lag. A monthly average for each of the components set out above, including working cash allowance, is calculated and an average of the monthly averages is calculated. The average of monthly averages is then summed and the total is added to rate base.
	Included in Rate Base: The amount of working capital required for operations is included in the applicant's rate base determination. Approved by the Board in July 2014, the plan is effectively a five year cost of service plan, in which rate base is an annual average of monthly asset continuity schedules. Rate base, including working capital, for each year of the Custom Incentive Rate-setting plan is set out in the Appendix A of the OEB's August 22, 2014 Decision and Rate Order.
	ICM Calculation: Not applicable. On July 3, 2013 Enbridge Gas Distribution applied for a Custom Incentive Rate-setting plan for the 2014 - 2018 rate years, inclusively. The Board approved the application, with modifications on July 17, 2014. The approved plan provides for an annual rate adjustment process and specific capital plans for each year. Rate base (including working capital), accumulated depreciation and asset continuity schedules are calculated using monthly average balances for each year during the term of the Custom IR period.

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	Description
Treatment of Working Capital	**Working Capital** is the amount of funds required to finance the day-to-day operations of a regulated utility and is included as part of rate base for ratemaking purposes. The determination of working capital relies on a lead-lag study to determine cash working capital. Cash working capital is one of a number of components that comprise the Allowance for Working Capital that is included in rate base. Other components include: (1) average cost of gas in storage and line pack gas; (2) average cost of balancing gas; (3) average cost of ABC receivable (gas in storage); (4) average cost of inventory of stores and spare equipment; (5) average cost of prepaid and deferred expenses; (6) average customer deposits; and (7) average customer deposit interest.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: A lead/lag study is conducted to determine cash working capital. The study considers the time between when the utility has received a good or service and when payment is made, known as the Expense Lead and the time between when the utility has provided a good or service and when it receives payment, known as the Revenue Lag. The difference between the Expense Leads and the total Revenue Lags is the Net Lag. A monthly average for each of the components set out above, including cash working capital, is calculated and an average of the monthly averages is calculated. The average of monthly averages is then summed and the total is added to rate base.
	Included in Rate Base: The amount of working capital required for operations is included in the applicant's rate base determination.
	ICM Calculation: On July 31, 2013, Union Gas filed a multi-year Incentive Regulation Mechanism that will be used to set Union's regulated distribution, transportation and storage rates over the 2014 to 2018 period, inclusively. The IR parameters are the product of a comprehensive Settlement Agreement and the Settlement Agreement was approved by the Board on October 7, 2013. Working capital is not specifically addressed in the Settlement Agreement. It is embedded in base rates, as per Union's cost of service model approved by the Board in 2012 for rates effective January 1, 2013. There is a custom ICM mechanism set out in the comprehensive Settlement Agreement. It is unclear whether there is an adjustment for working capital in the cost of the assets that qualify for the capital pass-through mechanism.

	Description
Treatment of Working Capital	**Necessary Working Capital** represents the amount of funds required to sustain utility operations from the time expenditures are made until the time payment is received. It is also a component of the rate base for ratemaking purposes. The determination of necessary working capital relies on a lead-lag study. Components of necessary working capital include: operating expenses, income tax expense, materials and supplies inventory, unamortized computer system costs, rate case expense, GST, retailer deposits, depreciation expense, interest expense, preferred equity, and common equity (retained earnings and dividends).
	13%: Allowance Approach: Not applicable.
	Lead/Lag Study: The purpose of the study is to determine necessary working capital, the timing differences between when the distributor provides a good or service and when it receives payment (lead/revenue) and the time between when the distributor receives a good or service and when payment is made (lag/expenses). Leads and lags are measured in days and are dollar-weighted based on the most recent actual operating revenues and expenses data. Lead/lag days in the test period are also forecasted based on the most recent actual lead/lag day data available. Necessary working capital is calculated as follows: the dollar-weighted net lag days (i.e. lag minus lead) is divided by the number of days in the year and then multiplied by the forecast annual test cash expense for each component of working capital.
	Included in Rate Base: The calculated Necessary Working Capital is included in the rate base. Rate base is determined by adding: (1) necessary working capital - as described above; and (2) net mid-year PPE. Net mid-year PPE is calculated using the mid-year base convention (i.e., the average of adjusted prior year net PPE and test year net PPE). Opening gross PPE for the test year (t) is calculated by taking the adjusted gross PPE balance for the previous year (t-1) and adding planned capital additions and deducting retirements. Accumulated depreciation in the test year (t) is then calculated as follows: accumulated depreciation at the beginning of the test year plus forecast gross provision depreciation, retirements, net salvage and adjustments. Gross provision depreciation for the test year (t) is calculated by: (1) applying the full depreciation rate to the previous year's (t-1) net PPE; plus (2) applying the full depreciation rate to net capital additions closed to PPE during the test period and dividing by 2. Net PPE is the difference between gross PPE and accumulated depreciation. The rate base for the test year is used to determine the return the cost of capital to be recovered in rates.
	ICM Calculation: As set out below, the calculation of the K Factor rate adjustments will be similar to revenue requirement calculations under cost of service, except that the calculation will be limited to the depreciation, taxes and return associated with the incremental rate base for the expenditures that form the capital tracker. An allowance for working capital is not included in the revenue requirement calculation for the K Factor rate adjustment.

	Description
Treatment of Working Capital	**Cash Working Capital** allowance represents the average amount of capital provided by investors above and beyond investments in plant and other separately identified rate base items. These investments bridge the gap between the time expenditures are made and payment is received.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: The cash working capital allowance is determined using a lead/lag study, which analyzes cash flows arising from the utility's billing, payment, and collections procedures. The purpose of the analysis is to determine the average amount of outstanding working capital to be included in rate base. Rate base is calculated as set out below.
	Included in Rate Base: The cash working capital allowance is included in the calculation of average rate base for the test year. In the regulatory proceeding before the UARB rate base is calculated as sum of: net regulated plant in service, construction work in progress, deferred charges, allowance for working capital, and allowance for materials and supplies. The rate base for the test year is then added to the rate base calculation for the year prior to the test year (t-1) and an average is taken. This average rate base calculation is used to determine the cost of capital elements to be recovered in rates, using the mid-range cost of capital metrics approved by the UARB, which are: 9% ROE (range 8.75% to 9.25%) and deemed equity of 37.5% (range of 35% to 40%). Net regulated plant in service for the test year is calculated as: beginning gross plant at the commencement of the test year, plus additions, less retirements, and less depreciation.
	ICM Calculation: Not applicable. Nova Scotia Power Inc. is regulated on a two-year, forward test year basis where rates are determined using a cost of service methodology. The Nova Scotia Utility and Review Board (UARB) has used a rate base approach to rate setting since 2006.

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	Description
Treatment of Working Capital	**Allowance for Working Capital** represents that lag between when revenue is earned and when the funds are received for that revenue, offset by when expenses are incurred and when the funds are released to pay for the expenses.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: The allowance for working capital is determined using a lead/lag study and represents the amounts required to compensate the utility for the timing difference between when expenditures are required to provide service and when collections are received for that service.
	Included in Rate Base: The Allowance for Working Capital is added to the Rate Base. Rate base is calculated as the sum of: Gross plant in service at the beginning of the test year plus net additions, CWIP not subject to AFUDC, plant acquisition adjustment and deferred and preliminary charges. Accumulated depreciation and amortization and contributions in aid of construction are then deducted. The remaining amount is called the Depreciated Rate Base. The Depreciated Rate Base for the test year (t) is then added to the Depreciated Rate Base for the prior year (t-1) and an average is taken. This is the Mean Depreciated Utility Rate Base. The allowance for working capital is added. A further adjustment for capital additions is also added or deducted, as discussed below. The final total is the Mid-Year Utility Rate Base. The Mid-Year Utility Rate Base is used to calculate the cost of capital recovered in rates. Depreciation expense for the test year is equal to the product of the relevant depreciation rate for the asset class and the asset balance at the end of the previous period (t-1). Accumulated depreciation reflected in the rate base calculation is the sum of depreciation expense for the test year, depreciation associated with utility plant adjustment, leasehold improvements, rate stabilization, less recoveries. The capital additions adjustment is the difference between total monthly weighted capital expenditures and the simple average of capital expenditures closed to rate base in the test year (total capital expenditures divided by 2). If monthly weighted capital expenditures are less than average capital expenditures, the difference is negative and this negative value is deducted from the Mean Depreciated Utility Rate Base for the test year, as set out previously.
	ICM Calculation: The allowance for working capital is included in the calculation of base rates, as set out below.

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	Description
Treatment of Working Capital	**Cash Working Capital** allowance represents the average amount of capital provided above and beyond investments in plant and other separately identified rate base items. In the situation where the payment of an expense precedes the collection of its related revenue stream, the utility's investor must supply capital to finance the expense until the receipt of the related revenues.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: The cash working capital allowance is determined using a lead/lag study, which is informed by: (i) revenue lags; (ii) expense lags; and (iii) leads/lags associated with HST in the test years. Rate base is comprised of the sum of average net regulated plant in service, cash working capital as per the Lead/Lag Study, and a materials and supplies allowance.
	Included in Rate Base: The cash working capital allowance is included in the calculation of rate base for the test year. Net average plant investment is calculated as the opening plant investment at the commencement of the test year plus capital additions expected to close to rate base during the test year. This sum is the closing plant investment for the test year. This value is then added to the closing plant investment for the previous year (t-1) and an average is taken. The composite depreciation rate is then applied to the average plant investment to determine the depreciation expense to be reflected in rates for the test year. This amount is deducted from the average plant investment, resulting in the net average plant investment for the test year. Average rate base reflected in the test year is calculated as follows: Net average plant investment **plus** deferred charges, regulatory assets (defined benefit pension plans), cost recovery deferrals, customer finance programs, **less** weather normalization reserve, other post employee benefits, customer security deposits, accrued pension obligation, future income taxes, and demand management incentive amount. To this amount, described as Average Rate Base Before Allowances, the cash working capital allowance and materials and supplies allowance are added, resulting in the Average Rate Base at Year End. With the exception of the cash working capital and materials and supplies allowances, all other balances are expressed on an average basis (for the test year). The Average Rate Base at Year End is used to determine the cost of capital to be recovered in test year rates.

	Description
	ICM Calculation: Not applicable. Newfoundland Power is regulated on a forward test year basis where rates are determined using an Asset Rate Base Method. The Asset Rate Base Method was approved for use by the Board of Commissioners of Public Utilities in conjunction with the utility's 2008 general rate application. Pursuant to this approach, the utility is able to include allowances for deferred charges, regulatory assets, customer finance programs, and other cost recovery deferral amounts in rate base. Deductions from rate base include weather normalization reserve, OPEBs, customer security deposits, accrued pension obligation, and demand management incentive amounts. These amounts are included in the calculation of average rate base to which the cash working capital and materials and supplies allowances are added.

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	Description
Treatment of Working Capital	**Working Capital** is comprised of cash working capital and materials and gas inventories. Cash working capital is calculated using a lead/lag study, as described below. Materials and gas inventories are averaged by taking the sum of balances at the beginning of the year and the end of each12-month period during the test year and dividing by 13.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: Cash working capital is determined using a lead/lag study. Leads and lags are measured in days. Expense lead is the time between the date when the distributor receives goods and services from its suppliers and vendors and the date that is pays for them. Revenue lag is the time between the date customers receive service and the date that customers' payments are available to the distributor. The net lag is calculated by subtracting the lead from the lag. Net lag is divided by the number of days in a given year and multiplied by forecast expenses to determine cash working capital.
	Included in Rate Base: Working capital is included in the calculation of rate base. Rate base is calculated as follows: net PPE less net customer contributions plus working capital plus unamortized costs (including rate stabilization accounts, commercial programs, and deferred natural gas costs). Average rate base is calculated by taking the sum of: (1) rate base on the first day of the fiscal year (October 1); and (2) rate base in each month of the fiscal year (October to September) divided by 13. Net PPE is calculated as: (1) gross assets; minus (2) accumulated depreciation.
	ICM Calculation: Not applicable. Rates are currently set using a cost of service approach. The GazMétro-QDA incentive mechanism, in effect since October 1, 2007, expired on September 30, 2012. A new incentive mechanism has not yet been approved by the Régie de l'énergie.

Appendix 2 U.S. Jurisdictional Review

Alabama Public Service Commission – Alabama Power Company

	Description
Treatment of Working Capital	**Working Capital** <u>Cash</u> component is not included in rate filings <u>Non-cash</u> component is measured on same basis as rate base (see "ICM Calculation" below) and consists of an projected 13-month average balance from three accounts: • Fuel Stock (Account 151) • Materials and Supplies (Account 154) • Merchandise (Account 155)
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Non-cash working capital is included in the calculation of rate base. Rate base is the sum of: (1) Electric Plant in Service, (2) Electric Plant Held for Future Use, (3) Construction Work in Progress, (4) Nuclear Fuel, (5) Non-utility property, (6) Non-cash working capital).

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	Description
Treatment of Working Capital	**Working Capital** Cash component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses. Operational cash requirements (e.g., minimum bank balances, special deposits and prepayments) are added to this amount. Non-cash component is measured on same basis as rate base (see "ICM Calculation" below) and consists of a 13-month average balance from two accounts: • Materials and Supplies • Emission Credits
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base. Rate base is the sum of: (1) Electric Plant in Service, (2) Capitalized software, (3) Other intangibles, (4) Non-cash working capital (see above). Accumulated Deferred Income Taxes and Depreciation and Amortization are subtracted from the previous summed amount.

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	Description
Treatment of Working Capital	**Working Capital** <u>Cash</u> component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses. Operational cash requirements (e.g., minimum bank balances, special deposits and prepayments) are added to this amount. <u>Non-cash</u> component is measured on same basis as rate base (see "ICM Calculation" below) and consists of a 13-month average balance for several accounts: • Fuel inventory • Materials and Supplies • Prepaid pension assets
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base. Rate base is the sum of: (1) Electric Plant in Service, (2) Nuclear fuel, (3) Electric Plant Held for Future Use, (4) Non-cash working capital (see above). Accumulated Deferred Income Taxes, Customer Deposits and Depreciation and Amortization are subtracted from the previous summed amount.

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	Description
Treatment of Working Capital	**Working Capital** <u>Cash</u> component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses over the 12-month historic test year ending June 30, 2012. <u>Non-cash</u> component is also comprised of a 13-month average. It is comprised of: • Fuel inventory • Materials and Supplies • Prepayments including property insurance reserve, injuries and damages reserves, unfunded pension, commercial litigation and environmental reserves
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base. Rate base is the sum of: (1) Plant in Service, (2) Plant Held for Future Use, (3) Plant Acquisition Adjustment (4) Rate case expenses and (5) Working capital (see above). Accumulated Deferred Income Taxes, Customer Deposits and Depreciation and Amortization are subtracted from the previous summed amount.

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	Description
Treatment of Working Capital	**Working Capital** Cash component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses using information from the 12-months of calendar year 2009. The leads and lags are then applied to 12-month test year revenues and operating expenses. Non-cash component is also comprised of a 13-month average. It is comprised solely of materials and supplies
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base. Rate base is the sum of: (1) Utility plant in service, (2) Construction work in progress, (3) Property held for future use, (4) Unamortized environmental costs, (5) Unamortized deferred conservation program expenditures and (6) Working capital (see above). Accumulated deferred income taxes, Customer deposits, Customer contributions in aid of construction and Depreciation and Amortization are subtracted from the previous summed amount.

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	Description
Treatment of Working Capital	**Working Capital** Cash component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses over the 12-month adjusted year ending December 31, 2010. The adjusted year is derived from historic test year data for the 12 month period ending December 31, 2008. Non-cash component is also comprised of a 12-month adjusted year ending December 31, 2010 that is derived from historic test year data for the 12 month period ending December 31, 2008. It is comprised solely of Materials and Supplies.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Non-cash working capital is included in the calculation of rate base. Rate base equals (1) Plant in Service Plus (2) Working Capital Less (3 Contributions in Aid of Construction, (4) Accumulated Depreciation and Amortization, (5) Accumulated Deferred Income Taxes and (5) Customer Deposits.

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	Description
Treatment of Working Capital	**Working Capital** <u>Cash</u> component is not included in working capital. Currently, a small amount – for compensating bank balances and working funds – is included <u>Non-cash</u> component is included on a 13-month average basis for the test year. It is comprised of: • Fuel stock • Materials and Supplies • Prepayments
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: not applicable because no cash working capital is included
	Included in Rate Base: Non-cash working capital is included in the calculation of rate base. Rate base is the sum of: (1) Gross Electric Plant, (2) Construction Work in Progress, (3) Plant Held for Future Use and (4) Working capital (see above). Accumulated Deferred Income Taxes, Customer Advances, Customer Deposits, Injuries & Damages Reserve, and Depreciation and Amortization are subtracted from the previous summed amount.

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	Description
Treatment of Working Capital	**Working Capital** Cash component is based on the application of the FERC formula – one eighth of O&M expenses (also known as "the 45-day rule"). Con Edison removes the following expenses from O&M before applying the formula: • Purchased power and fuel • System benefit charges • Renewable portfolio charges • Interdepartmental rents • Uncollectibles Non-cash component is included on an historical 12-month average basis for the test year and on a projected 12-month average basis for the rate year. It is comprised of: • Materials and Supplies (including liquid fuel inventories) • Prepayments
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: not applicable; see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base. Rate base is the sum of: (1) Book Cost of Plant, (2) Non-Interest Bearing Construction Work in Progress (CWIP), (3) Unamortized Debt Discount/Premium/Expense (4) Unbilled Revenues (excluding deferred fuel), (5) Deferred Fuel – Net of Tax and (6) Working capital (see above). Accumulated Deferred Income Taxes, Customer Advances for Construction, and Depreciation and Amortization are subtracted from the previous summed amount.

	Description
Treatment of Working Capital	**Working Capital** Cash component is based on a comprehensive lead-lag approach involving separate estimates of days outstanding for revenues and detailed O&M expenses. Non-cash component is included on a projected 12-month future test year that is derived from a 13-month average for the historical test year. It is comprised of: • Materials and Supplies • Prepaid Expenses
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: see "cash" component of working capital above
	Included in Rate Base: Both cash and non-cash working capital are included in the calculation of rate base. Rate base is the sum of: (1) Utility Plant and (2) Working capital (see above). Accumulated Deferred Income Taxes, Customer Deposits, Customer Advances for Construction, and Depreciation and Amortization are subtracted from the previous summed amount.

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	Description
Treatment of Working Capital	**Working Capital** is not calculated.
	13% Allowance Approach: Not applicable.
	Lead/Lag Study: Not applicable.
	Included In Rate Base: Real Asset Value (RAV) is a key building block for the price control review. RAV is the basis upon which the rate regulated entity receives a depreciation allowance and earns a return on capital pursuant with the regulatory cost of capital. Additions to RAV are based on the proportion of Total Expenditure (Totex) allowed as "slow money". Total expenditures are comprised of: (1) controllable operating expenditures; (2) load related capital expenditures; (3) asset replacement capital expenditures; (4) other capital expenditures; and (5) non-operational capital expenditures. The annual net additions to RAV is calculated as a percentage of Totex. Ofgem's approved capitalization percentage of Totex is 85%. In other words, 85% of Totex is considered "slow money" and added to the RAV balance. The closing balance of RAV in year (t) is calculated as: Closing RAV in year (t-1) **plus** transfers **plus** net additions (i.e. "slow money" or 85% of Totex in year (t)) **minus** accumulated depreciation. The full depreciation for capital additions in the test year (t) are applied in year (t+1).
	ICM Calculation: The RIIO price control framework applies an eight year period (1 test year and 7 years in IRM). Under the RIIO, Ofgem asks companies to submit well justified business plans detailing how they intend to meet the RIIO framework objectives. The process starts with the publication of a strategy document in which Ofgem sets out the framework against which the various rate regulated entities will develop their plans. RIIO places a strong emphasis on stakeholder engagement and companies must get stakeholders' input and demonstrate how this has been used to develop their plans. Ofgem reviews these plans to determine what levels of proportionate treatment to apply. The Price Control Financial Model (PCFM) for RIIO price controls is the financial model which derives the incremental changes to the base revenue during the RIIO price control period. It does this by recalculating base revenues based on a limited number of updated variables. These variables fall into four broad categories: the annual cost of corporate debt, Totex components sufficient to apply the Totex incentive mechanism, new or amended allowances on uncertainty

	Description
	mechanisms, and certain financial adjustments (e.g. pension variables, tax variables and legacy adjustments). The Totex Incentive Mechanism (TIM) applies adjustments to the Totex figure used in the fast/slow money modelling of recalculated base revenue figures under the Annual Iteration Process. The adjustments reflect the amount of under or over expenditure by the licensee against Totex allowances and the Totex Incentive Strength Rate (incentive strength) for each licensee. The incentive strength is a percentage figure specified in Special Condition 6C for each licensee. It represents the percentage that a licensee bears in respect of an overspend against allowances or retains in respect of an underspend against allowances. The adjustment that is made to the Totex figures is the Funding Adjustment Rate (often called the 'sharing factor') which is calculated as 1 – incentive strength. Applying the Funding Adjustment Rate to the over (or under spend) gives the amount that is added to (or subtracted from) the Totex allowances included in recalculated base revenues. The TIM uses the actual Totex expenditure values reported to Ofgem by 31 July each year (subject to any revisions that may be required for corrections of data or for expenditure that is not regarded as efficient) and adjusts revenues in the following Relevant Year via the MOD term. The incentive mechanism therefore operates with a two year lag.

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TAB C

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VIA E-MAIL AND WEB POSTING

July 16, 2015

To: Licensed Electricity Distributors

Re: I. Updated Filing Requirements
II. Process for 2016 Incentive Regulation Mechanism ("IRM") Distribution Rate Applications

On October 18, 2012, the Ontario Energy Board issued its report, entitled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the RRFE Report). The RRFE Report provides a comprehensive performance–based approach to regulation and sets out three rate-setting methods: 4^{th} Generation Incentive Rate-setting (Price Cap IR), Custom Incentive Rate-setting (Custom IR) and the Annual Incentive Rate-setting Index (Annual IR Index).

Today, the OEB issued an update of its *Filing Requirements for Electricity Distribution Rate Applications: Chapter 1 – Overview, Chapter 2 – Cost of Service and Chapter 3 – Incentive Rate-Setting*. These filing requirements outline the information that the OEB requires an electricity distributor to file when it makes an application under the rate-setting methods set out in the RRFE Report. Draft versions of the models and schedules to Chapter 2 were issued on July 7, 2015 and these files should now be considered final. An updated cost allocation model was posted today. The Rate Generator, which accompanies a Price Cap IR or Annual IR index application under Chapter 3 of the filing requirements, will be published later in July.

I. Significant Changes to the Filing Requirements

No substantive changes have been made to Chapter 1 as a result of this year's update**.** Updates to Chapters 2 and 3 are as follows:

Updates to filing requirements as a result of policy developments

- *Residential rate design:* On April 2, 2015, the OEB released *New Distribution Rate Design for Residential Electricity Customers* (EB-2012-0410) which stated that all distributors are to transition to a fully fixed charge for the residential class using a standard method. The OEB issued further guidance on this implementation earlier today. This rate design will be implemented over a period of four years, beginning in 2016, with requirements for mitigation in certain circumstances. See sections 2.8.2 and 2.8.13 in Chapter 2 and section 3.2.3 of Chapter 3.

- *Working capital allowance*: On June 3, 2015, the OEB issued a letter announcing a new default working capital allowance of 7.5% in place of the previous 13%. Distributors who do not wish to use the default value can request approval for a distributor-specific working capital allowance supported by the appropriate evidence from a lead-lag study or equivalent analysis (section 2.2.1.3).

- *Advanced capital module:* On September 18, 2014, the OEB issued *New Policy Options for the Funding of Capital Investments* (EB-2014-0129) which outlined the new Advanced Capital Module. While work on considering the use of the half-year rule is still ongoing, distributors can propose an alternative approach within their applications as applicable, for the OEB's consideration (section 2.2.2.6).

- *Allocation of costs to streetlighting class*: On June 12, 2015, the OEB released a letter announcing a new cost allocation policy for the streetlighting rate class. The cost allocation section of Chapter 2 has been updated to reflect this new policy (section 2.7.1).

Other Significant Changes to Chapter 2: Cost of Service

- The Executive Summary section (2.1.2) now requires separate identification of all proposed changes that will have a material impact on customers including any changes to rates and charges that may affect discrete customers or groups of customers as well as changes to reflect the new notice process.

- The Scorecard Performance Evaluation section (2.0.5) has been revised to incorporate a requirement to explain the drivers for a distributor's performance. In addition, the Service Quality and Reliability Performance section contains revised wording to reflect the OEB's new policy on targets.

- The adoption of the International Financial Reporting Standards ("IFRS") on January 1, 2015 is mandatory for most rate regulated distributors in Ontario. As a result, the Filing Requirements reflect only the transition from CGAAP to IFRS. The OEB will no longer accept applications filed by distributors under CGAAP (section 2.0.4).

- The Filing Requirements provide information on the interrelationship between the requirements outlined in Chapter 2 and those contained in Chapter 5 (the *Consolidated Distribution System Plan Filing Requirements),* which was issued by the OEB on March 28, 2013. There are no further updates to Chapter 5 at this time. The consolidated distribution system plan must be contained in one integrated and cohesive stand-alone document incorporating all elements of the plan (section 2.2.2.2).

- Section 2.9.7 Disposition of Deferral and Variance Accounts has been updated to enhance filing requirements for the Global Adjustment (GA) variance account (Account 1589) to support a more in-depth review.

- The 2016 Filing Requirements incorporate two new sections: Notional Debt, (2.5.2) which provides clarification of this area and Stand-by Rates (2.7.1) which allows applicants to seek the final approval of the interim charge conditional on confirmation that all affected customers have been advised.

Other Significant Changes to Chapter 3: Incentive Rate-Setting

- To streamline the filing process and make better use of data already filed with the OEB, the IRM rate generator models will now be prepopulated with customized tariff sheets for each distributor. The consumption and customer data fields contain RRR data and the models now use the most recent year-end data as the default basis for calculating deferral and variance account rates. Each distributor must confirm the accuracy of all pre-populated data and make changes where necessary and justified.

- Similarly to Chapter 2, the section on Global Adjustment (3.2.5.2 of the Filing Requirements) has been updated.

II. Scope and Timing of the IRM Process

As a means of managing the Price Cap and Annual Index applications, the OEB has established four filing dates for distributors. The application filing deadlines for each group were determined so that, in the normal course of events, a decision would be issued in time for a January 1 or May 1 implementation date. The application groupings are as follows:

Stream	Application Filing Deadline
1	August 17, 2015
2	September 28, 2015
3	October 19, 2015
4	November 2, 2015

Stream 1 is for those distributors applying for a January 1, 2016 effective date for rates. Applicants for May 1 rates have been assigned to one of three filing dates based on the expected level of complexity of the application. The assignments were based on the results of a survey of distributors circulated June 9, 2015. The attached table lists the assignment of each electricity distributor to one of the streams.

Distributors are reminded that the IRM application process is intended to be mechanistic in nature and therefore the filing requirements include certain exclusions. Furthermore, if a distributor contemplates a material increase to the complexity of its application relative to the information it provided in the survey, it should advise the OEB and is encouraged to file in an earlier stream.

As outlined in RRFE Report, the OEB will establish the final inflation factor and stretch factor to apply to distributors for the 2016 rate year in due course. The Rate Generator will initially include rate-setting parameters from the 2015 rate year as a placeholder. OEB staff will adjust the Rate Generator once updated rate-setting parameters and RTSRs are available.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

Encl.

Schedule : IRM Stream Assignment for 2016

Company	EB - Number	Stream	Filing Date
Algoma Power Inc.	EB-2015-0051	1	Aug. 17
Brantford Power Inc.	EB-2015-0055	1	Aug. 17
Canadian Niagara Power Inc.	EB-2015-0058	1	Aug. 17
Cooperative Hydro Embrun Inc.	EB-2015-0063	1	Aug. 17
Enersource Hydro Mississauga Inc.	EB-2015-0065	1	Aug. 17
Festival Hydro Inc.	EB-2015-0069	1	Aug. 17
Hydro Hawkesbury Inc.	EB-2015-0077	1	Aug. 17
Hydro One Brampton Networks Inc.	EB-2015-0078	1	Aug. 17
Innpower Corporation	EB-2015-0081	1	Aug. 17
Kitchener-Wilmot Hydro Inc.	EB-2015-0084	1	Aug. 17
Lakeland Power Distribution Limited	EB-2015-0086	1	Aug. 17
Oakville Hydro Electricity Distribution Inc.	EB-2015-0094	1	Aug. 17
St. Thomas Energy Inc.	EB-2015-0102	1	Aug. 17
Atikokan Hydro Inc.	EB-2015-0052	2	Sept. 28
Centre Wellington Hydro Ltd.	EB-2015-0059	2	Sept. 28
Collus PowerStream Corp.	EB-2015-0062	2	Sept. 28
E.L.K. Energy Inc.	EB-2015-0064	2	Sept. 28
Newmarket-Tay Power Distribution Ltd.	EB-2015-0213	2	Sept. 28
Niagara Peninsula Energy Inc.	EB-2015-0090	2	Sept. 28
Niagara-on-the-Lake Hydro Inc.	EB-2015-0091	2	Sept. 28
North Bay Hydro Distribution Limited	EB-2015-0092	2	Sept. 28
Peterborough Distribution Incorporated	EB-2015-0097	2	Sept. 28
Thunder Bay Hydro Electricity Dist.Inc.	EB-2015-0103	2	Sept. 28
Veridian Connections Inc.	EB-2015-0106	2	Sept. 28
Welland Hydro-Electric System Corp.	EB-2015-0109	2	Sept. 28
Brant County Power Inc.	EB-2015-0054	3	Oct. 19
EnWin Utilities Ltd.	EB-2015-0066	3	Oct. 19
Erie Thames Powerlines Corporation	EB-2015-0067	3	Oct. 19
Hydro 2000 Inc.	EB-2015-0076	3	Oct. 19
Lakefront Utilities Inc.	EB-2015-0085	3	Oct. 19
London Hydro Inc.	EB-2015-0087	3	Oct. 19
Midland Power Utility Corporation	EB-2015-0088	3	Oct. 19
Northern Ontario Wires Inc.	EB-2015-0093	3	Oct. 19
Orillia Power Distribution Corporation	EB-2015-0024	3	Oct. 19
PUC Distribution Inc.	EB-2015-0098	3	Oct. 19
Westario Power Inc.	EB-2015-0112	3	Oct. 19

Schedule : IRM Stream Assignment for 2016

Company	EB - Number	Stream	Filing Date
Bluewater Power Distribution Corporation	EB-2015-0053	4	Nov. 2
Burlington Hydro Inc.	EB-2015-0056	4	Nov. 2
Cambridge and North Dumfries Hydro Inc.	EB-2015-0057	4	Nov. 2
Fort Frances Power Corporation	EB-2015-0070	4	Nov. 2
Greater Sudbury Hydro Inc.	EB-2015-0071	4	Nov. 2
Hydro One Remote Communities Inc.	EB-2015-0080	4	Nov. 2
Kenora Hydro Electric Corporation Ltd.	EB-2015-0082	4	Nov. 2
Orangeville Hydro Limited	EB-2015-0095	4	Nov. 2
Sioux Lookout Hydro Inc.	EB-2015-0101	4	Nov. 2
Tillsonburg Hydro Inc.	EB-2015-0104	4	Nov. 2
West Coast Huron Energy Inc.	EB-2015-0111	4	Nov. 2