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March 4, 2016

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

Dear Ms. Walli,

Re: Wellington North Power Inc.
EB-2015-0110 - 2016 Cost of Service Application
Settlement Proposal

Wellington North Power Inc. (WNP) is pleased to advise the Board that all Parties were able to arrive at a complete settlement with respect to the Applicant's 2016 Cost of Service application (file number EB-2015-0110). Pursuant to Procedural Order No.2, please find attached the Settlement Proposal together with supporting documentation.

Wellington North Power Inc. confirms a copy of the settlement proposal has been filed through the Board's e-filing service together with updated models. As per requirements, two copies will be mailed to the Ontario Energy Board offices.

Should you have any questions, please do not hesitate to contact me.

Regards,

Richard Bucknall

Richard Bucknall
Chief Administrative Officer
Wellington North Power Inc.

Cc:	OEB:	Ms. Jane Scott and Mr. Michael Millar
Cc:	Intervenors:	Energy Probe Research Foundation; Vulnerable Energy Consumers Coalition
Cc:	Legal Counsel:	Mr. James Sidlofsky and Bruce Bacon

This document has been filed pursuant to the Board's e-filing Services.

Wellington North Power Inc.

2016 Cost of Service Application

Settlement Proposal

EB-2015-0110

Filed: March 4th 2016

Contents

LIST OF ATTACHMENTS

A. Proposed May 1, 2016 Tariff of Rates and Charges
B. Bill Impacts
C. Capital Expenditure Summary – Appendix 2-AB and Appendix 2AA
D. Revenue Requirement Work Form Model
E. PILs Model
F. Load Forecast Model
G. Cost Allocation Model
H. Retail Transmission Service Rates Model
I. Advanced Capital Module (ACM)
J. Draft Accounting Order – OPEBs
K. Draft Accounting Order – CapEx Project: 2nd Line Feeder (2016)
L. Latest Quote from HONI (February 10th 2016) for design, procurement and construction of 2nd Line Feeder

Note:

Wellington North Power Inc. has filed revised models as evidence to support this document. The models have been filed through the OEB's e-filing service and include:

a) Filing Requirements Chapter 2 Appendices
b) 2016 Load Forecast Model – Wholesale
c) 2016 Revenue Requirement Workform
d) 2016 EDDVAR Continuity Schedule
e) 2016 RTSR Model
f) 2016 Test Year Income Tax PILS model
g) 2016 ACM Model
h) Proposed Tariff of Rates and Charges

SETTLEMENT PROPOSAL

Wellington North Power Inc. (the "Applicant" or "WNP") filed a Cost of Service application with the Ontario Energy Board (the "OEB") on November 2nd 2015 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the "Act"), seeking approval for changes to the rates that WNP charges for electricity distribution, to be effective May 1, 2016 (OEB file number EB-2015-0110) (the "Application").

The OEB issued a Letter of Direction and Notice of Application on November 23rd 2015. In Procedural Order No. 1, dated December 15th 2015, the OEB sought the provision of written interrogatories and outlined the timetable of the various elements in the proceeding.

Following the receipt of interrogatories, WNP filed its interrogatory responses with the OEB on January 27th 2016 and filed responses to clarification questions with the OEB on February 8th 2016.

On February 1st 2016, following interrogatories and the issuance of clarification questions, OEB Staff submitted a proposed issues list as agreed to by the parties. On February 8th 2016 the OEB issued its decision on the proposed issues list, approving the list submitted by OEB staff as the final issues list (the "Issues List"), and confirmed that a settlement conference would occur in accordance with Procedural Order No. 1.

The settlement conference was convened on February 11th 2016 in accordance with the OEB's *Rules of Practice and Procedure* (the "Rules") and the OEB's Practice Direction on Settlement Conferences (the "Practice Direction"). Mr. Jim Faught acted as facilitator for the settlement conference which was held for one day.

WNP and the following intervenors (the "Intervenors"), participated in the settlement conference:

- Energy Probe Research Foundation ("EP"); and
- Vulnerable Energy Consumers Coalition ("VECC").

WNP and the Intervenors are collectively referred to below as the "Parties". Ontario Energy Board staff ("OEB staff") also participated in the settlement conference. The role adopted by OEB staff is set out in page 5 of the Practice Direction. Although OEB staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB staff who did participate in the settlement conference are bound by the same confidentiality and privilege rules that apply to the Parties to the proceeding.

This document is called a "Settlement Proposal" as this is a proposal by the Parties presented to the OEB to settle the issues in this proceeding. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this Preamble, this agreement is subject to a condition subsequent, that if it is not accepted by the OEB in its entirety, then unless amended by the Parties it is null and void and of no further effect. In entering into this agreement, the Parties understand and agree that, pursuant to the Act, the OEB has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Practice Direction. The Parties acknowledge that this settlement proceeding is confidential in accordance with the OEB's Practice Direction on Settlement Conferences. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's Practice Direction on Confidential Filings, and the rules of that latter document do not apply. Instead, in this settlement conference, and in this Settlement Proposal, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the settlement proceeding, 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 privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the settlement conference. However, the Parties agree that "attendees" is deemed to include, in this context, persons who were not physically in attendance at the settlement conference but were a) any persons or entities that the Parties engage to assist them with the settlement conference, and b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

This Settlement Proposal provides a brief description of each of the settled and partially settled issues, as applicable, together with references to the evidence. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include a) additional information included by the Parties in this Settlement Proposal, and b) the Appendices to this document. The supporting Parties for each settled and partially settled issue, as applicable, agree that the evidence in respect of that settled or partially settled issue, as applicable, is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the OEB of this Settlement Proposal. The Parties agree that references to the evidence in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the responses to interrogatories, responses to clarification questions and undertakings, and all other components of the record up to and including the date hereof, including additional information included by the Parties in this Settlement Proposal and the Attachments to this document.

Included with this Settlement Proposal are Attachments that provide further support for the proposed settlement. The Parties acknowledge that the Attachments were prepared by WNP. While the Intervenors have reviewed the Attachments, the Intervenors are relying on the accuracy of the underlying evidence in entering into this Settlement Proposal.

For ease of reference, this Settlement Proposal follows the format of the final Approved Issues List.

The Parties are pleased to advise the OEB that the Parties have reached a complete agreement with respect to all of the issues in this proceeding. Specifically:

Description	Number of Issues Settled
"Complete Settlement" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the OEB, the Parties will not adduce any evidence or argument during the oral hearing in respect of these issues.	All
"Partial Settlement" means an issue for which there is partial settlement as WNP and the Intervenors who take any position on the issue were able to agree on some but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the OEB, the Parties who take any position on the issue will only adduce evidence and argument during the hearing on those portions of the issues not addressed in this Settlement Proposal.	None
"No Settlement" means an issue for which no settlement was reached. WNP and the Intervenors who take a position on the issue will adduce evidence and/or argument at the hearing on the issue.	None

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

According to the Practice Direction (p. 3), the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. These adjustments are specifically set out in the text of the Settlement Proposal.

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

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

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not WNP is a party to such proceeding, provided that no Party shall take a position that would result in this Agreement not applying in accordance with the terms contained herein.

Where in this Agreement, the Parties “Accept” the evidence of WNP, or “Agree” to a revised term or condition, including a revised budget or forecast, then unless the Agreement expressly states to the contrary, the words “for the purpose of settlement of the issues herein” shall be deemed to qualify that acceptance or agreement.

SUMMARY

In reaching this Settlement Proposal, the Parties have been guided by the Filing Requirements for 2016 rates and the Approved Issues List.

This Settlement Proposal reflects a settlement of all of the issues in this proceeding.

WNP has made changes to the Revenue Requirement as presented below in Table 1:

TABLE 1: REVENUE REQUIREMENT

DESCRIPTION		APPLICATION (A)	IR RESPONSES (B)	VARIANCE (C) = (B) - (A)	SETTLEMENT (D)	VARIANCE (E) = (D) - (B)
Cost of Capital	Regulated Return on Capital	$570,249	$570,725	$476	$566,490	($4,235)
	Regulated Rate of Return	5.99%	6.01%	0.02%	5.99%	-0.02%
Rate Base & Capital Expenditures	Rate Base	$9,523,835	$9,496,255	($27,580)	$9,452,221	($44,034)
	Working Capital	$14,929,287	$15,819,859	$890,572	$15,818,423	($1,436)
	Working Capital Allowance ($)	$1,119,697	$1,186,489	$66,792	$1,186,382	($107)
Operating Expenses	Amortization / Depreciation	$361,570	$417,626	$56,056	$365,779	($51,847)
	Taxes/PILs	$0	$5,051	$5,051	$0	($5,051)
	OM&A	$1,793,368	$1,795,728	$2,360	$1,720,000	($75,728)
Revenue Requirement	Service Revenue Requirement	$2,743,188	$2,807,130	$63,942	$2,669,178	($137,952)
	Other Revenues	$150,588	$128,808	($21,780)	$130,105	$1,297
	Base Revenue Requirement	$2,592,599	$2,678,323	$85,724	$2,539,074	($139,249)
	Grossed up Revenue Deficiency (positive) OR Sufficiency (negative)	$258,891	$313,936	$55,045	$162,171	($151,765)

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

Please refer to Attachment A for updated Tariff of Rates and Charges based on the outcome of this Settlement Proposal which are subject to the OEB's acceptance.

Table 2 below illustrates the updated Bill Impacts based on the results of this Settlement Proposal.

TABLE 2: BILL IMPACT SUMMARY

Rate Class	Type	Typical kWh	Typical kW	Current Rates Total Bill	2016 Proposed Rates Total Bill	Change $	Change %
Residential	RPP	800		$ 140.11	$ 143.73	$3.62	2.58%
	Retailer			$ 167.23	$ 170.93	$3.70	2.21%
Residential (Low-user)	RPP	310		$ 66.79	$ 71.22	$4.43	6.63%
	Retailer			$ 77.66	$ 81.76	$4.10	5.28%
General Service <50 kW	RPP	2,000		$ 348.63	$ 355.94	$7.31	2.10%
	Retailer			$ 416.44	$ 423.94	$7.50	1.80%
General Service 50-999kW	Non-RPP		38,217	$ 5,436.53	$ 5,390.46	($46.07)	-0.85%
General Service 1000-4999 kW	Non-RPP		746,695	$ 96,159.75	$ 99,289.86	$3,130.11	3.26%
Unmetered Scattered Load	RPP	252		$ 57.24	$ 66.67	$9.43	16.47%
Sentinel Lighting	RPP		5	$ 363.31	$ 399.24	$35.93	9.89%
	Retailer			$ 428.64	$ 464.76	$36.12	8.43%
Street Lighting	Non-RPP		165	$ 9,149.26	$ 8,169.93	($979.33)	-10.70%

Note:
- Total Bill represents all components of the total monthly bill excluding HST

WNP acknowledges that the Unmetered Scattered Load rate class total bill impact is above a 10% increase. However, the applicant is not proposing rate mitigation on the basis that:

- The total bill impact is greater than 10% due to the small monthly usage associated with this rate class (an average monthly usage of 252 kWh);
- WNP has observed that energy used for this rate class has continually reduced from 2010 to date; however billing and servicing costs remain consistent; and
- There is only one (1) customer connection in the Unmetered Scattered Load rate class and this has been consistent for the past 5 years (2010 to 2015).

Attachment B contains the Bill Impacts by rate class for all components of WNP's monthly electricity bill.

RRFE OUTCOMES

In reaching this Settlement Proposal, the Parties have taken into consideration the outcomes as defined by the Renewed Regulatory Framework for Electricity (RRFE). Below is a summary of the outcomes:

a) Customer Focus:
The Parties acknowledge and accept that WNP has engaged with its customers in preparing its 2016 Cost of Service rate application, namely:
- The Applicant has addressed or is in the processing of addressing feedback from WNP's 2014 Customer Satisfaction survey including:
    - Preferred contact methods and use of social media;
    - Launch of Customer Connect and a new website that enables consumers to view their energy usage, past payments and ability to make a payment;
- Surveying large consumers independently (General Service 1,000-4,999kW) to assess load demand requirements that were included in the Applicant's Distribution System Plan;
- Organizing of public meetings to share information with rate-payers about capital plans and operating budgets; and
- Continued to promote the benefits of an LDC that has an office open 5 days a week with approachable and knowledgeable staff to address customers concerns, feedback or complaints.

b) Operational Effectiveness:
The Parties accept that WNP's proposed OM&A expenses, as modified by this Settlement Proposal, are driven by appropriate high-level objectives for the 2016 Test Year, as described in the evidence. Specifically, the Parties understand that the Applicants OM&A costs reflect the expenditures required to:
- Maintain and operate its distribution system assets;
- The costs associated with metering, billing and collecting from its customers;
- The costs associated with ensuring all stakeholders' safety (public and employees); and
- Costs to maintain the distribution service quality and reliability standards in compliance with the Distribution System Code and other regulatory bodies

(including Independent Electricity System Operator, Ministry of Energy, Ministry of Finance, etc.).

c) Public Policy Responsiveness:
For the purpose of settlement of the issues in this proceeding, the Parties accept WNP's confirmation that the resources available to it in the 2016 Test Year as result of this Settlement Proposal will allow it to meet all obligations currently mandated by the OEB and the Government relevant to this Application in the Test Year.

d) Financial Performance:
For the purpose of settlement of the issues in this proceeding, and subject to the adjustments noted in this Settlement Proposal, the Parties accept that WNP's proposed rates in the 2016 Test Year will, in all reasonably foreseeable circumstances, allow the Applicant to meet its obligations to its customers while maintaining its financial viability.

The Parties accept that the Applicant has adequately demonstrated it is using reasonable efforts to pursue operational effectiveness initiatives as referenced in the Applicant's Distribution System Plan. Furthermore, as discussed in section 1.1 of this settlement proposal, WNP has applied opportunities to divert labour costs from OM&A expense accounts to capitalized projects. This has resulted in reducing annual OM&A costs which in-turn has reduced the revenue requirement requested by WNP, therefore benefitting the ratepayer.

1 PLANNING

1.1 Capital

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

- Customer feedback and preferences;
- Productivity;
- Benchmarking of costs;
- Reliability and service quality;
- Impact on distribution rates;
- Trade-offs with OM&A spending;
- Government-mandated obligations; and
- The objectives of the Applicant and its customers.

COMPLETE SETTLEMENT

The Parties accept the evidence of WNP that all elements of the Capital Expenditures have been correctly determined in accordance with OEB policies and practices. Specific adjustments to Capital Expenditures as a result of the Settlement Proposal in the amount of $139,700 are further described below.

- Issue 1.1.1 – Second Line Feeder to Mount Forest.
- Issue 1.1.2 – Advanced Capital Module (ACM) in 2018.

A summary of Gross Capital Expenditures is presented in Table 3 below.

TABLE 3: 2016 GROSS CAPITAL EXPENDITURES (EXCLUDING DISPOSALS)

DESCRIPTION	APPLICATION (A)	IR RESPONSES (B)	VARIANCE (C) = (B) - (A)	SETTLEMENT (D)	VARIANCE (E) = (D) - (B)
System Access	$60,000	$60,000	$0	$60,000	$0
System Renewal	$50,000	$50,000	$0	$90,000	$40,000
System Service	$1,729,751	$1,552,961	($176,790)	$1,373,261	($179,700)
General Plant	$70,650	$70,650	$0	$70,650	$0
Total Expenditure	**$1,910,401**	**$1,733,611**	**($176,790)**	**$1,593,911**	**($139,700)**

1.1.1 Second Line Feeder to Mount Forest

Regarding "System Service", as per the Applicant's Distribution System Plan, WNP is planning to build a second line feeder to the town of Mount Forest to primarily address current demand capacity limitations to this community which will restrict future growth and secondly to provide an alternative supply in the event of prolonged power outages (as encountered in the ice-storm of April 2013). WNP is an embedded distributor fed by Hydro One Networks Inc. (HONI). The proposed second line feeder will be constructed by HONI from Palmerston to WNP's service territory. (WNP and HONI explored alternative solutions as discussed in Appendix D – "HONI Town of Mount Forest Supply Study" filed with the Applicant's DSP in Exhibit 2 of the application.)

In its application, WNP included an estimate based on a 2014 "fixed price" and indexed for inflation to 2016 rates of $1,269,751. When responding to interrogatories it was noted that the "fixed price" methodology was not in accordance with OEB Policy or HONI's Conditions of Service and consequently, the revised cost estimate of $1,092,961 was used (based on an Economic Evaluation by HONI) – a difference of $176,790 between application and IR responses.

On February 11, 2016 (on the day of the Settlement Conference), HONI provided to WNP a revised cost estimate of $881,156 (before HST) based on 2016 construction rates. WNP provided this latest information in the Settlement Conference indicating the total cost, including HST, was $1,027,767 which consists of:

- $881,156 for design, procurement and construction by HONI for the 44kV pole line;
- $114, 550 for HST (@ 13%) on the above; and
- $32,061 for the 2014 HONI Supply Study of Mount Forest.

Attachment L contains details of the latest quote received from HONI on February 11th 2016.

In updating the Fixed Asset Continuity Schedule and 2016 Capital Plan, WNP has used the amount of $913,217 based on:

- HONI's Capital Contribution Required from WNP of $881,156 (before HST)
- Plus the cost of HONI's 2014 study of $32,061 (before HST) that WNP expensed in 2014.)

(The difference of $179,700 for System Service presented in Table 5 between IR Responses and Settlement submission is as a result of HONI's revised cost estimate as described above.)

All Parties agree that:

a) For the purpose of establishing the 2016 Test Year revenue requirement, the capital expense for this project should be treated as $913,217. (The estimated capital expense for this project, including HST, is $1,027,767);

b) The HONI cost of $931,217 plus the work required by WNP (a pole-line project and PME Metering) with an estimated cost of $460,000 (excluding HST) should be treated as one combined project.

   Hydro One will construct the line extension up to WNP's service territory boundary at Highway 6 and Bentley Street. WNP will construct a new pole line would from Highway 6 and Bentley Street to the LDC's Municipal Substation 1 where the extension would connect to the existing 44kV system. As well as new pole line construction work, WNP will also be responsible for acquiring and installing primary metering equipment (PME) at Highway 6 and Bentley Street.

c) A symmetrical variance account will be established to reflect the difference in revenue requirement associated with the estimated cost of the combined project and the actual cost and timing of the project on an annual basis until the next rebasing cost of service application or customer IR application. At the next rebasing cost of service application or customer IR application, the disposition of the balance of the symmetrical variance account will be addressed. The parties agree that there is a need for this account given the changing cost estimates from HONI and that the timing of the project is beyond the control of WNP.

The Applicant notes that in terms of measuring implementation of its Distribution System Plan (DSP) in WNP's Scorecard, the HONI costs will be included. If required, WNP may need to explain any deviation for costs and timing for this project in its commentary in the LDC's Scorecard.

All Parties agreed that an additional pole-line project in 2016, with a cost estimate of $40,000, would be included to assist with meeting the agreed 2016 OM&A budget. (Operations labour cost of approximately $10,000 associated with this pole-line work would be allocated to this capital project and subsequently capitalized. Consequently, labour costs are diverted from being charged to labour expense accounts.) This has been included, hence the $40,000 variance between Settlement and IR Responses in Table 3 above for System Renewal. (WNP has added $40,000 for a capital pole-line replacement project in each subsequent year (2017, 2018, 2019 and 2020) to assist with diverting approximately $10,000 of labour costs to capital projects instead of labour expense accounts.)

1.1.2 Advanced Capital Module (ACM) in 2018

In its application, WNP included an Advanced Capital Module (ACM) for 2018 to replace an aged/deteriorated substation. WNP acquired the services of Costello Associates Inc. to provide supporting technical information and budgetary estimates for an asset condition assessment of six of its distribution substations. This independent 3rd party report with findings and recommendation was issued to WNP in June 2013. This study identifies deficiencies in the substations that require attention. Page 2 of the report states the concern regarding the age of these substations and combined with overall condition lead to the planned replacement.

The ACM filed with the Application reflected the estimated costs for replacing WNP’s MS3 Substation. Details about this “special” capital project, including background, scope, options explored and supporting material can be found in WNP’s 2016 DSP, Section 5.4.5.3.2.

All Parties accepted WNP’s evidence in support of the ACM. WNP has updated the ACM model to incorporate the changes in depreciation agreed as discussed in section 2.1.4. The table below summarizes the proposed ACM project and the “Maximum Eligible Incremental Capital (forecasted CapEx less Threshold)

TABLE 4: ACM 2018 PROJECT WITH THRESHOLD TEST

	Cost of Service	Price Cap IR			
	Test Year	Year 1	Year 2	Year 3	Year 4
	2016	2017	2018	2019	2020
Distribution System Plan CAPEX	$ 1,593,911	$768,670	$2,196,470	$951,850	$963,000
Materiality Threshold		$653,131	$ 659,768	$666,580	$673,572
Maximum Eligible Incremental Capital (Forecasted CAPEX less Threshold)		$115,539	$1,536,702	$285,270	$289,428
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$115,539	$1,536,702	$285,270	$289,428
Proposed Capital Projects Eligible for ACM treatment					
	Cost of Service	Price Cap IR			
Project Descriptions:	Test Year	Year 1	Year 2	Year 3	Year 4
	2016	2017	2018	2019	2020
Replacement Substation MS3 including Recloser Smart Technology			$1,672,000		
Maximum Allowed Incremental Capital		$ -	$1,536,702	$ -	$ -

All Parties accept WNP's ACM for 2018. The Applicant will file updated information on the forecasted costs and will demonstrate that the capital project still qualifies for incremental capital funding and recovery in its 2017 rate application seeking approval for 2018 distribution rates with latest forecast and revenue data at that time.

Attachment I of this Settlement Proposal provides the ACM Threshold Test and the updated ACM Model has been filed through the OEB's e-filing service.

For the purposes of settlement of all the issues in this proceeding, the Parties accept the evidence of WNP that the level of planned capital expenditures and the rationale for planning and pacing choices are appropriate in order to maintain system reliability, service quality objectives and the reliable and safe operations of the distribution system. The Parties further acknowledge that the planned capital expenditures are adequately explained, giving due consideration to:

- WNP's customer feedback and preferences as explained in:
  - Exhibit 1 / Section 1 / Tab 5
  - Exhibit 1 – Appendix 1A

    - 2016 Filing Requirements – Chapter 2 Appendices / worksheet App.2-AB: Capital Expenditures
- Exhibit 2 – Appendix 2A: Distribution System Plan:
    - Section 5.2.2.3 – Consultations with Customers
    - Section 5.2.3.4 – System Reliability and Performance
    - Section 5.2.3.5 – Customer Focus
    - Section 5.4.2 – CapEx Planning Process
    - Section 5.4.5 – Justifying Capital Expenditures
    - Section 5.4.5.3 – Special Projects
    - Section 5.0 –Appendix 5D: Hydro One Networks Inc. Town of Mount Forest Supply Study
    - Section 5.0 –Appendix 5E: Stakeholder letters supporting 2nd feeder
    - Section 5.0 –Appendix 5F: 3rd Party Substation Assessment Study
- Total impact on distribution rates as detailed in Attachment B of this Settlement Proposal

The Parties further agree that the Distribution System Plan filed in this proceeding, combined with the resources made available to WNP in the Test Year under the terms of this Settlement Proposal, provide a foundation to WNP in the Test Year to continue to:

- Maintain system reliability and service quality objectives; and
- Maintain reliable and safe operation of its distribution system.

Attachment C of this Settlement Proposal provides updated Capital Expenditure Summary – Appendix 2-AB to reflect this settlement.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 2 / Tab 1 / Schedule 3
- Exhibit 2 / Tab 1 / Schedule 4
- Exhibit 2 / Tab 2 / Schedule 1
- Exhibit 2 / Tab 2 / Schedule 2
- Exhibit 2 - Appendix 5A: WNP's Distribution System Plan:
    - Section 5.4.5.3 – Special Projects
    - Section 5.0 –Appendix 5D: HONI Inc. Town of Mount Forest Supply Study
    - Section 5.0 –Appendix 5E: Stakeholder letters supporting 2nd feeder
    - Section 5.0 –Appendix 5F: 3rd Party Substation Assessment Study

IR Responses dated January 27th 2015:

- IR 2-Staff-7, pages 25-29
- IR 2-Staff-14, pages 40-41
- IR 2-Staff-23, pages 56-57
- IR 2-Staff-25, page 61
- IR 2-Staff-29, pages 67-68
- IR 2-Staff-30, pages 69-71
- IR 2-VECC-7, page 75
- IR 2-VECC-8, pages 76-77
- IR 2-VECC-11, pages 80-81
- IR 2-VECC-13, pages 84-85

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

1.2 OM&A

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

- Customer feedback and preferences;
- Productivity;
- Benchmarking of costs;
- Reliability and service quality;
- Impact on distribution rates;
- Trade-offs with capital spending;
- Government-mandated obligations; and
- The objectives of the Applicant and its customers.

COMPLETE SETTLEMENT

The Parties accept the evidence of WNP that all elements of the OM&A expenditures have been correctly determined in accordance with OEB policies and practices. Specific adjustments to OM&A expenditures as a result of the Settlement Proposal are summarized below and are described in detail in the specified sections further below:

- Issue 1.2.1 – OM&A Expenditures
- Issue 1.2.2 – OPEBs

A summary of the adjusted OM&A expenditures is presented in Table 5 below. For the purpose of presentation, WNP has identified in the table below the revised OM&A budget for the 2016 Test Year, and has indicated reductions totaling $79,728. The Parties acknowledge that the ultimate determination of the areas of OM&A in which reductions will be made is at the discretion of WNP.

TABLE 5: 2016 TEST YEAR OM&A EXPENDITURES

DESCRIPTION	APPLICATION	IR RESPONSES	VARIANCE	SETTLEMENT	VARIANCE
	(A)	(B)	(C) = (B) - (A)	(D)	(E) = (D) - (B)
Operations	$411,500	$421,900	$10,400	$420,000	($1,900)
Maintenance	$239,500	$239,500	$0	$234,500	($5,000)
Billing & Collecting	$395,000	$395,000	$0	$361,000	($34,000)
Community Relations	$7,000	$7,000	$0	$7,000	$0
Administration & General	$740,368	$732,328	($8,040)	$697,500	($34,828)
Total OM&A Expenditure	**$1,793,368**	**$1,795,728**	**$2,360**	**$1,720,000**	**($75,728)**
LEAP	$4,000	$4,000	$0	$2,909	($1,091)
Property Taxes	$14,000	$14,000	$0	$14,000	$0
Total Controllable Expenditure	**$1,811,368**	**$1,813,728**	**$2,360**	**$1,736,909**	**($76,819)**

For the purposes of settlement of all the issues in this proceeding, the Parties accept the evidence of WNP that the level of planned OM&A expenditures and the rationale for planning choices are appropriate and adequately explained, giving due consideration to:

- WNP's customer feedback and preferences as explained in:
  - Exhibit 1 / Section 1 / Tab 5
  - Exhibit 1 – Appendix 1A
- Exhibit 2 – Appendix 2A: Distribution System Plan:
  - Section 5.2.2.3 – Consultations with Customers
  - Section 5.2.3.4 – System Reliability and Performance
  - Section 5.2.3.5 – Customer Focus
  - Section 5.4.5.3 – Special Projects
  - Section 5.0 –Appendix 5D: Hydro One Networks Inc. Town of Mount Forest Supply Study
  - Section 5.0 –Appendix 5E: Stakeholder letters supporting 2nd feeder
  - Section 5.0 –Appendix 5F: 3rd Party Substation Assessment Study
- IR Response 4-Staff-44 regarding Benchmarking
- Total impact on distribution rates as detailed in Attachment B of this Settlement Proposal
- The agreed to changes in OM&A spending as described in Issue 1.2.1 of this Settlement Proposal

1.2.1 OM&A Expenditures

For the purposes of the settlement of all issues in this proceeding, The Parties agree to reduce the OM&A expenditures in the 2016 Test Year by $$75,728.

The Parties agree that WNP's proposed OM&A expenses, as modified by this Settlement Proposal, support the planning choices and are adequately explained.

The evidence in this proceeding regarding OM&A expenditures provided a starting point for discussions which resulted in a Settlement Proposal which is agreeable to all Parties and provides a basis to support acceptance by the OEB. In reaching this agreement, consideration was given to historical spending levels, inflation, efficiencies, customer growth and planned initiatives in response to customer needs and preferences, including power quality enhancements and improved customer service capabilities.

For the purposes of the settlement of the issues in this proceeding, the Parties agree to the proposed OM&A expenses in this Settlement Proposal. The Intervenors have relied on WNP's view that it can safely and reliably operate the distribution system based on the total OM&A budget established in this Settlement Proposal. WNP confirms that it will be able to achieve its business objectives as outlined in Exhibit 1 in the 2016 Test Year.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 4 / Tab 1 / Schedule 1
- Exhibit 4 / Tab 2 / Schedule 1
- Exhibit 4 / Tab 2 / Schedule 2
- Exhibit 4 / Tab 3 / Schedule 2
- Exhibit 4 / Tab 3 / Schedule 3
- Exhibit 4 / Tab 3 / Schedule 7
- Exhibit 4 / Tab 3 / Schedule 8
- Exhibit 4 / Tab 3 / Schedule 9

IR Responses dated January 27th 2015:

- IR 4-Staff-42, pages 147-149
- IR 4-Staff-42, pages 147-149
- IR 4-Staff-43, page 150

- IR 4-Staff-44, page 151
- IR 4-Staff-45, page 152
- IR 4-Staff-46, page 153
- IR 4-VECC-28, page 161
- IR 4-VECC-30, pages 163-166
- IR 4-VECC-32, pages 168-169
- IR 4-Energy Probe-17, pages 171-172
- IR 4-Energy Probe-19, pages 175-176
- IR 4-Energy Probe-20, pages 177-178
- IR 4-Energy Probe-17, pages 181-184

Clarification Question Responses dated February 8th 2016:
- 4-Energy Probe-21 – CQ 4, page 9

Supporting Parties:
All

1.2.2 OPEBs

Recognizing the OEB will address the method for the accounting of OPEBs in rates as part of a generic policy process, all Parties agree that a variance is required to reflect the difference in OPEBs between cash and accrual method. Based on the evidence provided WNP's response to interrogatory 4-Staff-45 showing the cumulative difference between accrual and cash of $(32,087) between 2011 to 2015, all parties believed that it would be prudent to record the variance which, in the future, may be material (i.e. reach WNP's materiality threshold of $50,000).

As per WNP's responses to interrogatories, the Applicant has included $12,568 in its OM&A and therefore requires the new variance account, as described further in the settlement of Issue 4.2.3 below, to record the difference in rates between these two methodologies pending the OEB's final determination on this generic policy issue.

Table 6 below presents the adjustments related to recovery for the change to reflect OPEBs on a cash basis.

TABLE 6: OPEBS ACCOUNT CHANGE

DESCRIPTION	Cash Basis	Accrual Basis	Adjustment
OPEBs	$12,568	$568	$12,000

Evidence References:

Application dated November 2nd 2015:

- Exhibit 4 / Tab 3 / Schedule 1 – page 35
- Exhibit 4 – Appendix 4H: Actuarial Report

IR Responses dated December 18, 2015:

- IR 4-Staff-45, page 152
- IR 4-Energy Probe-22, page 180

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

1.2.3 Property Taxes and LEAP

The Parties agree that the inclusions in OM&A of $14,000 for Property Tax and $2,909 for LEAP Program funding are appropriate. WNP calculated 2016 LEAP Funding in accordance with the "Filing Requirements for Electricity Distribution Rate Applications", Chapter 2 – Cost of Service dated July 16, 2015.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 4 / Tab 5 / Schedule 1, pages 79-80
- Exhibit 4 / Tab 3 / Schedule 9

IR Responses dated January 27th 2015:

- None

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

2 REVENUE REQUIREMENT

2.1 Are all elements of the Revenue Requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?

COMPLETE SETTLEMENT

The Parties accept the evidence of WNP that all elements of the Revenue Requirement have been correctly determined in accordance with OEB policies and practices. Specific adjustments to Revenue Requirement as a result of the IR Responses and the Settlement Proposal are summarized below and are described in detail in the relevant sections:

- Issue 2.1.1 Cost of Capital
- Issue 2.1.2 Rate Base
- Issue 2.1.3 Working Capital
- Issue 2.1.4 Depreciation
- Issue 2.1.5 Taxes
- Issue 2.1.6 Other Revenue

A summary of the adjusted Revenue Requirement is presented in Table 7 below.

TABLE 7: REVENUE REQUIREMENT

DESCRIPTION		APPLICATION (A)	IR RESPONSES (B)	VARIANCE (C) = (B) - (A)	SETTLEMENT (D)	VARIANCE (E) = (D) - (B)
Cost of Capital	Regulated Return on Capital	$570,249	$570,725	$476	$566,490	($4,235)
	Regulated Rate of Return	5.99%	6.01%	0.02%	5.99%	-0.02%
Rate Base & Capital Expenditures	Rate Base	$9,523,835	$9,496,255	($27,580)	$9,452,221	($44,034)
	Working Capital	$14,929,287	$15,819,859	$890,572	$15,818,423	($1,436)
	Working Capital Allowance ($)	$1,119,697	$1,186,489	$66,792	$1,186,382	($107)
Operating Expenses	Amortization / Depreciation	$361,570	$417,626	$56,056	$365,779	($51,847)
	Taxes/PILs	$0	$5,051	$5,051	$0	($5,051)
	OM&A	$1,793,368	$1,795,728	$2,360	$1,720,000	($75,728)
Revenue Requirement	Service Revenue Requirement	$2,743,188	$2,807,130	$63,942	$2,669,178	($137,952)
	Other Revenues	$150,588	$128,808	($21,780)	$130,105	$1,297
	Base Revenue Requirement	$2,592,599	$2,678,323	$85,724	$2,539,074	($139,249)
	Grossed up Revenue Deficiency (positive) OR Sufficiency (negative)	$258,891	$313,936	$55,045	$162,171	($151,765)

An updated Revenue Requirement Work Form Model is included in Attachment D of this Settlement Proposal and has been filed through the OEB's e-filing service.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 3 / Tab 1 / Schedule 1
- Exhibit 3 / Tab 1 / Schedule 2
- Exhibit 3 / Tab 5 / Schedule 1
- Exhibit 3 / Tab 5 / Schedule 2
- Exhibit 3 / Tab 1 / Schedule 3
- Exhibit 2 - Appendix 5A: WNP's Distribution System Plan
  - Section 5.4.5.3 – Special Projects
  - Section 5.0 –Appendix 5D: Hydro One Networks Inc. Town of Mount Forest Supply Study
  - Section 5.0 –Appendix 5E: Stakeholder letters supporting 2nd feeder
  - Section 5.0 –Appendix 5F: 3rd Party Substation Assessment Study

IR Responses dated January 27th 2015:

- IR 3-Staff-32, page 98
- IR 3-Staff-33, pages 99-101
- IR 3-Staff-34, page 102
- IR 3-Staff-37, page 106
- IR 3-Staff-38, page 107
- IR 3-Staff-40, page 111
- IR 3-VECC-15, pages 112-114
- IR 3-VECC-16, pages 115-117
- IR 3-VECC-18, pages 120-122
- IR 3-VECC-20, pages 127-129
- IR 3-Energy Probe-11, pages 133-134
- IR 3-Energy Probe-13, pages 138-140

Clarification Question Responses dated February 8th 2016:

- 3-Energy Probe-13 – CQ 2, pages 4-7
- 3-Energy Probe-16 – CQ 3, page 8

Supporting Parties:

All

2.1.1 Cost of Capital

For the purposes of settlement, WNP has agreed to adjust its long term debt rate resulting in a weighted average cost of capital rate of 5.99% for the 2016 Test Year. This rate reflects:

- The cost of capital parameters for 2016 Cost of Service applications as adjusted for long term debt rates for loans secured prior to WNP's 2016 rate application;
- Interest rate adjustment from 4.02% to 3.76% for a pending 2016 financing loan for $1,100,000 over a 25 year term from Infrastructure Ontario as agreed by all Parties; and
- Affiliate Debt interest rate to be held at the OEB's current long-term debt rate of 4.54% for the period of this (2016) cost of service application and for the period of the next rebasing cost of service rate application or customer IR application.

Table 8 below details the long term debt rate calculation. The change in the long term debt rate resulted in a reduction of the Regulated Return on Capital of $1,588 as shown in the Revenue Requirement Work Form, worksheet "10. Tracking Sheet", Item 17 included in Attachment D.

TABLE 8: LONG TERM DEBT RATE CALCULATION

Debt Instruments

Year 2016

	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%)	Interest ($)	Additional Comments, if any
1	Promissory Note	Township of Wellington North	Third-Party	Fixed Rate	1/Nov/01		$ 985,016	4.54%	$ 44,719.73	
2	Smart Meter Funding	Infrastructure Ontario	Third-Party	Fixed Rate	1/Jun/11	15	$ 875,377	4.42%	$ 38,691.66	
3	Capital Projects (2008 & 2009)- Re-Financing	Infrastructure Ontario	Third-Party	Fixed Rate	2/Dec/13	5	$ 261,058	2.46%	$ 6,422.03	
4	Capital Projects (2008 & 2009)- Re-Financing	Infrastructure Ontario	Third-Party	Fixed Rate	2/Dec/13	30	$ 1,063,597	4.49%	$ 47,755.51	
5	MS2 Substation Re-Build (2014	Infrastructure Ontario	Third-Party	Fixed Rate	2/Apr/15	30	$ 1,120,236	3.28%	$ 36,743.74	
6	Secondary Feed Loan	Infrastructure Ontario	Third-Party	Fixed Rate	2/Jul/16	25	$ 560,755	3.76%	$ 21,084.39	Rate Based on IO rate on Feb 10, 2016
						Total	**$ 4,866,039**	**4.02%**	**$ 195,417.05**	

TABLE 9: COST OF CAPITAL

Description	Capitalization Ratio %	Capitalization Ratio $	Cost Rate %	Return $
Debt				
Long-term Debt	56.00%	$5,293,122	4.02%	$212,783
Short-term Debt	4.00%	$378,080	1.65%	$6,238
Total Debt	**60.00%**	**$5,671,202**	**3.86%**	**$219,022**
Equity				
Common Equity	40.00%	$3,780,801	9.19%	$347,456
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	**40.00%**	**$3,780,801**	**9.19%**	**$347,456**
Total	**100.00%**	**$9,452,003**	**5.99%**	**$566,477**

The Parties accept that WNP's calculation of the proposed capital structure and the associated cost of capital have been correctly determined in accordance with OEB policies and practices.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 5 / Tab 1 / Schedule 1
- Exhibit 5 / Tab 1 / Schedule 4
- 2016 Filing Requirements – Chapter 2 Appendices / worksheet App.2-OA: Capital Structure
- 2016 Filing Requirements – Chapter 2 Appendices / worksheet App.2-OB: Cost of Debt Instruments

IR Responses dated January 27th 2015:

- IR 5-VECC-35, pages 194-195
- IR 5-VECC-36, page 196
- IR 5-VECC-37, page 197
- IR 5-Energy Probe-31, page 199
- IR 5-Energy Probe-32, page 200

Clarification Question Responses dated February 8th 2016:

- 5-VECC-35 – CQ 61, page 11

Supporting Parties:

All

2.1.2 Rate Base

WNP has agreed to make the adjustments to Rate Base as described in the settlement of Issue 1.1 above. Also, adjustments have been captured in relation to the settlement of Issues 2.1.3 and 2.1.4 noted below.

Subject to the adjustments to the Rate Base described above and presented in Table 10 below, the Parties accept the evidence of WNP that the 2016 Test Year Rate Base is correct and based on OEB policies and practices.

TABLE 10: RATE BASE

DESCRIPTION	APPLICATION (A)	IR RESPONSES (B)	VARIANCE (C) = (B) - (A)	SETTLEMENT (D)	VARIANCE (E) = (D) - (B)
Gross Fixed Assets (average)	$16,008,237	$15,886,144	($122,093)	$15,816,294	($69,850)
Accumulated Depreciation (average)	($7,604,099)	($7,576,378)	$27,721	($7,550,454)	$25,924
Net Fixed Assets (average)	$8,404,138	$8,309,766	($94,372)	$8,265,840	($43,926)
Working Capital Base	$14,929,287	$15,819,859	$890,572	$15,818,423	($1,436)
Working Capital Allowance (%)	7.50%	7.50%	0.00%	7.50%	0.00%
Allowance for Working Capital ($)	$1,119,697	$1,186,489	$66,793	$1,186,382	($108)
Rate Base	$9,523,835	$9,496,255	($27,579)	$9,452,221	($44,035)

Evidence References:

Application dated November 2nd 2015:

- Exhibit 2 / Tab 1 / Schedule 1
- Exhibit 2 / Tab 1 / Schedule 2
- Exhibit 2 / Tab 1 / Schedule 3
- Exhibit 2 / Tab 1 / Schedule 4
- Exhibit 2 / Tab 2 / Schedule 1
- Exhibit 2 / Tab 2 / Schedule 2
- Exhibit 2 / Tab 3 / Schedule 1
- Exhibit 2 / Tab 3 / Schedule 2
- Exhibit 2 / Tab 4 / Schedule 1
- Exhibit 2 / Tab 5 / Schedule 1
- Exhibit 2 / Tab 5 / Schedule 2
- Exhibit 2 / Tab 5 / Schedule 7
- Exhibit 2 - Appendix 5A: WNP's Distribution System Plan
    - Section 5.4.5.3 – Special Projects
    - Section 5.0 –Appendix 5D: Hydro One Networks Inc. Town of Mount Forest Supply Study

- Section 5.0 –Appendix 5E: Stakeholder letters supporting 2nd feeder

IR Responses dated January 27th 2015:

- IR 2-Staff-6, page 24
- IR 2-Staff-7, pages 25-29
- IR 2-Staff-8, page 30
- IR 3-Energy Probe-13, pages 138-140
- IR 4-Energy Probe-25, page 186

Clarification Question Responses dated February 8th 2016:

- 2-Staff-6 & 2-Energy Probe-4 – CQ 1, page 4

Supporting Parties:

All

2.1.3 Working Capital

The Working Capital Allowance base has been updated to reflect the agreed upon updates to:

- The load forecast adjusting the Cost of Power;
- The level of OM&A;
- The Retail Transmission rates (Issue 3.4.1) adjusting the Cost of Power;
- Low Voltage rates (Issue 3.4.2) adjusting the Cost of Power;
- The Regulatory charges that came into effect January 1, 2016 (Issue 3.3.4) namely revised Wholesale Market Service rates and introduction of Ontario Electricity Support Program (OESP) that affect the Cost of Power; and
- The proposal that a $25,000 deduction to the Working Capital Allowance is made to reflect the fully allocated depreciation of assets included in OM&A expense.

The Parties accepted the revised Working Capital Allowance amount incorporating the changes noted above. Table 11 below illustrates the calculation of the Working Capital Allowance:

TABLE 11: WORKING CAPITAL ALLOWANCE CALCULATION

DESCRIPTION	APPLICATION (A)	IR RESPONSES (B)	VARIANCE (C) = (B) - (A)	SETTLEMENT (D)	VARIANCE (E) = (D) - (B)
Operations	$411,500	$421,900	$10,400	$420,000	($1,900)
Maintenance	$239,500	$239,500	$0	$234,500	($5,000)
Billing & Collecting	$395,000	$395,000	$0	$361,000	($34,000)
Community Relations	$7,000	$7,000	$0	$7,000	$0
Administration & General	$740,368	$732,328	($8,040)	$697,500	($34,828)
LEAP	$4,000	$4,000	$0	$2,909	($1,091)
Property Tax	$14,000	$14,000	$0	$14,000	$0
Total Controllable Expenses	**$1,811,368**	**$1,813,728**	**$2,360**	**$1,736,909**	**($76,819)**
Cost of Power	$13,117,919	$14,006,130	$888,211	$14,106,514	$100,384
Adjustment				($25,000)	($25,000)
Working Capital Base	$14,929,287	$15,819,858	$890,571	$15,818,423	($1,435)
Working Capital Allowance (%)	7.50%	7.50%	0.00%	7.50%	0.00%
Working Capital Allowance ($)	**$1,119,697**	**$1,186,489**	**$66,793**	**$1,186,382**	**($108)**

Evidence References:

Application dated November 2nd 2015:

- Exhibit 2 / Tab 3 / Schedule 1

- Exhibit 2 / Tab 3 / Schedule 2

IR Responses dated January 27th 2015:
- IR 2-Staff-12, pages 35-36
- IR 8-VECC-43, page 229

Clarification Question Responses dated February 8th 2016:
- None

Supporting Parties:
All

2.1.4 Depreciation

In its application, WNP presented information concerning failure rates of installed Smart Meters and proposed that the typical useful life for Smart Meters be reduced from 15 years to 10 years. In responding to interrogatories, WNP adjusted the depreciation period to 10 years for Smart Meters in the Fixed Asset Continuity Schedule to calculate the impact of amortization expense and the subsequent change in revenue requirement. WNP applied a 10-year useful life as this aligns with the 10-year seal date for Smart Meters as per Measurement Canada. The Applicant also commented that at 10 years, the meters would need to be sample tested by Measurement Canada and this would increase operating costs to account for removal of each meter and installation of a replacement meter.

Although in its application, WNP had provided data demonstrating meter failure rates, the Applicant had not included in its evidence any 3rd party studies to support changing the typical useful life of Smart Meters to 10 years. .

For the purposes of settlement, the Parties accepted the depreciation rate for this application for Smart Meters should remain at 15 years. WNP has amended the Fixed Asset Continuity Schedule to reflect Smart Meters having a typical useful life of 15 years which has reduced amortization expense.

As per Issue 1.1, the additional pole-line project in 2016 and the revised HONI cost estimate for the 2016 second line feeder project, have been included / updated into the Fixed Asset Continuity Schedule and reflect a $4,209 increase in 2016's amortization compared to the WNP's application.

The Parties accept the evidence of WNP that its forecast depreciation/amortization expenses are appropriate and reflect the useful lives of the assets and that depreciation has been correctly determined in accordance with OEB accounting policies and practices.

TABLE 12: DEPRECIATION

DESCRIPTION	APPLICATION (A)	IR RESPONSES (B)	VARIANCE (C) = (B) - (A)	SETTLEMENT (D)	VARIANCE (E) = (D) - (B)
Depreciation/Amortization	$361,570	$417,626	$56,056	$365,779	($51,847)

Evidence References:

Application dated November 2nd 2015:

- Exhibit 4 / Tab 4 / Schedule 1
- Exhibit 4 / Tab 4 / Schedule 2
- Exhibit 4 / Tab 4 / Schedule 3
- Exhibit 4 / Tab 4 / Schedule 4
- Exhibit 4 / Tab 4 / Schedule 5
- Exhibit 4 / Tab 4 / Schedule 6
- Exhibit 4 / Tab 4 / Schedule 7

IR Responses dated January 27th 2015:

- IR 2-Staff-8, page 30
- IR 2-Staff-9, page 31
- IR 2-Staff-23, pages 56-57
- IR 2-Staff-27, page 64
- IR 4-VECC-31, page 167
- IR 4-Energy Probe-5, page 90
- IR 4-Energy Probe-24, page 185
- IR 4-Energy Probe-25, page 186
- IR 4-Energy Probe-26, pages 187-188
- IR 4-Energy Probe-27, page 189

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

2.1.5 Taxes

For the purposes of settlement of all the issues in this proceeding, and subject to the other adjustments arising in this Settlement Proposal, the Parties accept the evidence of WNP that its forecast PILs are appropriate and have been correctly determined in accordance with OEB accounting policies and practices.

A summary of the adjusted PILs is presented in Table 13 below.

TABLE 13: INCOME TAXES

DESCRIPTION	APPLICATION	IR RESPONSES	VARIANCE	SETTLEMENT	VARIANCE
	(A)	(B)	(C) = (B) - (A)	(D)	(E) = (D) - (B)
Grossed-up Income Taxes	$0	$5,051	$5,051	$0	($5,051)

PILS has changed to $0 because regulatory taxable income has reduced from $27,537 (IR) to $(25,937) as a consequence of the changes accepted in the settlement conference. An updated PILs Model is included in Attachment E of this Settlement Proposal and has been filed through the OEB's e-filing service.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 4 / Tab 5 / Schedule 1
- Exhibit 4 / Tab 5 / Schedule 2
- Exhibit 4 / Tab 5 / Schedule 3
- Exhibit 4 / Tab 5 / Schedule 4
- Exhibit 4 / Tab 5 / Schedule 5

IR Responses dated January 27th 2015:

- None

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

2.1.6 Other Revenue

The Parties have agreed to increase the 2016 Test Year Other Revenue by $1,297 as a consequence of increasing the Monthly Service Charge for MicroFIT accounts as discussed in Issue 2.1.7 below. This results in a Test Year amount of $130,105 which is consistent with 2015 year to date actual results.

TABLE 14: OTHER REVENUE

DESCRIPTION	APPLICATION (A)	IR RESPONSES (B)	VARIANCE (C) = (B) - (A)	SETTLEMENT (D)	VARIANCE (E) = (D) - (B)
Specific Service Charges	$58,115	$57,000	($1,115)	$58,297	$1,297
Late Payment Charges	$27,012	$29,000	$1,988	$29,000	$0
Other Distribution / Operating Revenues	$60,751	$61,308	$557	$61,308	$0
Other Income or Deductions	$2,000	($18,500)	($20,500)	($18,500)	$0
Total	$147,878	$128,808	($19,070)	$130,105	$1,297

Evidence References:

Application dated November 2nd 2015:

- Exhibit 3 / Tab 4 / Schedule 1
- Exhibit 3 / Tab 4 / Schedule 2
- Exhibit 3 / Tab 4 / Schedule 3
-

IR Responses dated January 27th 2015:

- IR 3-Staff-40, page 111
- IR 3-VECC-20, pages 127-129
- IR 3-VECC-21, page 130
- IR 3-Energy Probe-16, pages 143-145

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

2.1.7 MicroFIT Monthly Service Charge

In its Application, WNP proposed increasing the Monthly Service Charge (MSC) for its MicroFIT accounts. The current MSC is $5.40 however WNP incurs a $10.00 monthly fee per microFIT meter point from its vendor and is of the opinion this charge should be passed onto its microFIT customers. Furthermore, in responding to interrogatories, WNP noted that applying the same cost structure for MicroFIT meters to that of a Residential metered customer, using the data in sheet "O3.6 - MicroFIT Charge" in the Cost Allocation schedule, then the calculated MicroFIT Monthly Unit Cost would actually be $15.69, inclusive of the $10.00 monthly settlement vendor fee.

Based upon the evidence presented, all Parties agreed that the Monthly Service Charge per MicroFIT account should be $15.69.

The impact on "Other Revenue" due to this increase in the MSC for MicroFIT accounts is shown below:

TABLE 15: OTHER REVENUE

<table>
<tr><td rowspan="2">DESCRIPTION</td><td>APPLICATION</td><td>IR RESPONSES</td><td>VARIANCE</td><td>SETTLEMENT</td><td>VARIANCE</td></tr>
<tr><td>(A)</td><td>(B)</td><td>(C) = (B) - (A)</td><td>(D)</td><td>(E) = (D) - (B)</td></tr>
<tr><td>MicroFIT Monthly Service Charge (per account)</td><td>$10.00</td><td>$10.00</td><td>$0</td><td>$15.69</td><td>$5.69</td></tr>
<tr><td rowspan="3">Increase in "Other Revenue"</td><td>Number of accounts in 2016</td><td>Increase</td><td>Months</td><td>Total</td><td rowspan="3"></td></tr>
<tr><td>(A)</td><td>(B)</td><td>(C)</td><td>= (A) x (B) x (C)</td></tr>
<tr><td>19</td><td>$5.69</td><td>12</td><td>$1,297.32</td></tr>
</table>

Evidence References:

Application dated November 2nd 2015:

- Exhibit 3 / Tab 4 / Schedule 3

IR Responses dated January 27th 2015:

- IR 3-Staff-40, page 111
- IR 3-VECC-21, page 130
- IR 3-Energy Probe-16, pages 143-145

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

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

COMPLETE SETTLEMENT

For the purposes of settlement of all the issues in this proceeding, and subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept the evidence of WNP that the proposed Base Revenue Requirement has been determined accurately.

A revised Revenue Requirement Work Form is included in Attachment D of this Settlement Proposal and has also been filed through the OEB's e-filing service.

3 LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

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

COMPLETE SETTLEMENT

The Parties accept the evidence of WNP that the methodology used for the load forecast, customer forecast, loss factors and CDM adjustments have been determined in accordance with OEB policies and practices or any differences with the same are not material. Specific adjustments as a result of IR Responses and the Settlement Proposal are summarized immediately below and are described in detail in the specified sections further below:

- Issue 3.1.1 – Customer/Connections Forecast
- Issue 3.1.2 – Load Forecast
- Issue 3.1.3 – Loss Factors
- Issue 3.1.4 – CDM Adjustments

The resulting billing determinants are presented in Table 16 below.

TABLE 16: 2016 TEST YEAR BILLING DETERMINANTS (FOR COST ALLOCATION AND RATE DESIGN)

Rate Class	Customers / Connections	kWh	kW
Residential	3,251	27,408,200	
General Service <50kW	476	12,494,682	
General Service 50 - 999 kW	38	14,065,279	43,362
General Service 1,000 to 4,999 kW	5	50,613,209	108,301
Street Lights (connections not devices)	905	725,392	1,995
Sentinel Lights	29	23,128	65
Unmetered Scattered Loads	1	3,024	
Total	**4,705**	**105,332,914**	**153,723**

Note: kWh and KW forecasted energy volumes are after CDM adjustments have been applied.

An updated copy of WNP's Load Forecast Model is included in Attachment F of this Settlement Proposal and has also been filed through the OEB's e-filing service.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 3 / Tab 1 / Schedule 1
- Exhibit 3 / Tab 1 / Schedule 2
- Exhibit 3 / Tab 1 / Schedule 3
- Exhibit 3 / Tab 1 / Schedule 4
- Exhibit 3 / Tab 1 / Schedule 5
- Exhibit 3 / Tab 1 / Schedule 6
- Exhibit 3 / Tab 1 / Schedule 7
- Exhibit 3 / Tab 1 / Schedule 8
- Exhibit 3 / Tab 1 / Schedule 9
- Exhibit 3 / Tab 1 / Schedule 10
- Exhibit 3 / Tab 1 / Schedule 11
- Exhibit 3 / Tab 1 / Schedule 12
- Exhibit 3 / Tab 1 / Schedule 13
- Exhibit 3 / Tab 2 / Schedule 1
- Exhibit 3 / Tab 2 / Schedule 2
- Exhibit 3 / Tab 2 / Schedule 3
- Exhibit 3 / Tab 3 / Schedule 1
-

IR Responses dated January 27th 2015:

- IR 3-Staff-32, page 98
- IR 3-Staff-33, pages 99-101
- IR 3-Staff-34, page 102
- IR 3-Staff-36, pages 104-105
- IR 3-VECC-16, pages 115-117
- IR 3-VECC-18, pages 120-122
- IR 3-Energy Probe-10, page 132
- IR 3-Energy Probe-12, pages 135-137
- IR 3-Energy Probe-13, pages 138-140

Clarification Question Responses dated February 8th 2016:

- 2-Staff-6 & 2-Energy Probe-4 – CQ 1, page 4

Supporting Parties:

All

3.1.1 Customer/Connection Forecast

The Parties accepted WNP's 2016 Test Year customer / connection forecast as proposed in the Application with no changes and summarized below:

TABLE 17: SUMMARY OF LOAD FORECAST CUSTOMER COUNTS/CONNECTIONS

RATE CLASS ACCOUNTS / CONNECTIONS	APPLICATION (A)	IR RESPONSES (B)	VARIANCE (C) = (B) - (A)	SETTLEMENT (D)	VARIANCE (E) = (D) - (B)
Residential	3,251	3,251	0	3,251	0
General Service <50kW	476	476	0	476	0
General Service 50 - 999 kW	38	38	0	38	0
General Service 1,000 to 4,999 kW	5	5	0	5	0
Street Lights (*connections not devices*)	905	905	0	905	0
Sentinel Lights	29	29	0	29	0
Unmetered Scattered Loads	1	1	0	1	0
Total	**4,705**	**4,705**	**0**	**4,705**	**0**

Evidence References:

Application dated November 2nd 2015:

- Exhibit 3 / Tab 1 / Schedule 10

IR Responses dated January 27th 2015:

- IR 3-VECC-17, pages 118-119
- IR 3-Energy Probe-9, page 131

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

3.1.2 Load Forecast

The Parties agree to increase 2016 Predicted kWh Purchases (prior to CDM adjustment) by 810,530 kWh to correct for trending of 2016 data using 2005 to 2014 actual data. The increase in forecasted purchases of 810,530 kWh is equivalent to an increase of 758,453 of forecasted billed kWh for 2016 Test Year. Table 18 below provides the weather normalized billed kWh forecast by rate class.

TABLE 18: SUMMARY OF LOAD FORECAST PREDICTED PURCHASES AND BILLED KWH

LOAD FORECAST (kWh)	APPLICATION (A)	IR RESPONSES (B)	VARIANCE (C) = (B) - (A)	SETTLEMENT (D)	VARIANCE (E) = (D) - (B)
2016 Predicted Purchases	111,517,168	113,503,939	1,986,771	114,314,469	810,530
2016 CDM Purchase Adjustment	(1,748,974)	(1,748,974)	0	(1,748,974)	0
Predicted Purchases after CDM Adjustment	109,768,194	111,754,965	1,986,771	112,565,495	810,530
2016 Forecasted Billed kWh	102,715,346	104,574,461	1,859,115	105,332,914	758,453
RATE CLASS ACCOUNTS / CONNECTIONS	**APPLICATION (A)**	**IR RESPONSES (B)**	**VARIANCE (C) = (B) - (A)**	**SETTLEMENT (D)**	**VARIANCE (E) = (D) - (B)**
Residential	26,005,466	27,001,751	996,285	27,408,200	406,449
General Service <50kW	11,855,213	12,309,393	454,180	12,494,682	185,289
General Service 50 - 999 kW	13,489,914	13,898,564	408,650	14,065,279	166,715
General Service 1,000 to 4,999 kW	50,613,209	50,613,209	0	50,613,209	0
Street Lights (connections not devices)	725,392	725,392	0	725,392	0
Sentinel Lights	23,128	23,128	0	23,128	0
Unmetered Scattered Loads	3,024	3,024	0	3,024	0
Total	**102,715,346**	**104,574,461**	**1,859,115**	**105,332,914**	**758,453**

The billed demand forecast for the 2016 Test Year is based on a four-year average ratio of kW to kWh for the classes that are billed distribution on a demand basis. A four-year (4-year) was used to cover the period of 2011 to 2014 to reflect reduced kW demand due to CDM programs delivered and implemented during this period. All Parties accepted this methodology that was described in WNP's Application. Table 19 below shows the 2016 Test Year kW Forecast.

TABLE 19: SUMMARY OF LOAD FORECAST KW

RATE CLASS ACCOUNTS / CONNECTIONS	APPLICATION (A)	IR RESPONSES (B)	VARIANCE (C) = (B) - (A)	SETTLEMENT (D)	VARIANCE (E) = (D) - (B)
Residential			0		0
General Service <50kW			0		0
General Service 50 - 999 kW	41,588	42,848	1,260	43,362	514
General Service 1,000 to 4,999 kW	108,301	108,301	0	108,301	0
Street Lights	1,995	1,995	0	1,995	0
Sentinel Lights	65	65	0	65	0
Unmetered Scattered Loads			0		0
Total	**151,949**	**153,209**	**1,260**	**153,723**	**514**

Evidence References:

Application dated November 2nd 2015:

- Exhibit 3 / Tab 1 / Schedule 11
- Exhibit 3 / Tab 1 / Schedule 12
- Exhibit 3 / Tab 1 / Schedule 13

IR Responses dated January 27th 2015:

- IR 3-VECC-16, pages 115-117
- IR 3-VECC-18, pages 120-122
- IR 3-Energy Probe-10, page 132
- IR 3-Energy Probe-12, pages 135-137
- IR 3-Energy Probe-13, pages 138-140

Clarification Question Responses dated February 8th 2016:

- 2-Staff-6 & 2-Energy Probe-4 – CQ 1, page 4

Supporting Parties:

All

3.1.3 Loss Factors

The Parties agree to the Loss Factors proposed in the Application with no changes as summarized below:

TABLE 20: LOSS FACTORS

DESCRIPTION	2016 Proposed
Total Loss Factor - Secondary Metered Customer <5,000 kW	1.0656
Total Loss Factor - Primary Metered Customer <5,000 kW	1.0549

Evidence References:

Application dated November 2nd 2015:

- Exhibit 8 / Tab 1 / Schedule 12

IR Responses dated January 27th 2015:

- IR 3-VECC-18, pages 120-122
- IR 3-VECC-19, pages 123-126
- IR 8-Staff-49, page 224
- IR 8-VECC-44, page 230

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

3.1.4 Load Forecast CDM Adjustments

The Parties agree to the Load Forecast CDM Adjustment by rate class proposed in the Application with no changes as summarized below:

TABLE 21: LOAD FORECAST CDM ADJUSTMENT

2016 Test Year CDM Adjustment to Load Forecast				
	Share	CDM kWh Target	Adjusted kWh	Final Adjusted kWh
Residential	25%	413,670	27,821,870	27,408,200
General Service < 50 kW	12%	188,581	12,683,264	12,494,682
General Service 50 to 999 kW	13%	215,359	14,280,638	14,065,279
				0
General Service 1000 to 4,999 kW	50%	818,988	51,432,197	50,613,209
Street Lights	0%	0	725,392	725,392
Sentinel Lights	0%	0	23,128	23,128
Unmetered Loads	0%	0	3,024	3,024
Total	**100%**	**1,636,599**	**106,969,514**	**105,332,916**

Evidence References:

Application dated November 2nd 2015:

- Exhibit 3 / Tab 2 / Schedule 1
- Exhibit 3 / Tab 2 / Schedule 2
- Exhibit 3 / Tab 2 / Schedule 3

IR Responses dated January 27th 2015:

- IR 3-Staff-37, page 106
- IR 3-Staff-38, page 107
- IR 3-VECC-18, pages 120-122
- IR 3-VECC-19, pages 123-126
- IR 3-Energy Probe-13, pages 138-140

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

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

COMPLETE SETTLEMENT

The table below shows the revenue to cost ratios determined by the OEB's Cost Allocation Model.

TABLE 22: SUMMARY OF 2016 REVENUE TO COST RATIOS AS PER OEB'S COST ALLOCATION MODEL

From OEB's Cost Allocation Model					
RATE CLASS	APPLICATION	IR RESPONSES	VARIANCE	SETTLEMENT	VARIANCE
	(A)	(B)	(C) = (B) - (A)	(D)	(E) = (D) - (B)
Residential	90%	91%	0%	90%	-1%
General Service <50kW	120%	118%	-2%	120%	2%
General Service 50 - 999 kW	152%	154%	2%	151%	-3%
General Service 1,000 to 4,999 kW	83%	82%	-1%	78%	-3%
Unmetered Scattered Loads	135%	137%	2%	115%	-22%
Sentinel Lights	65%	65%	1%	62%	-3%
Street Lights	198%	201%	3%	564%	363%

The Parties accept the evidence of WNP that all elements of the cost allocation methodology, allocation and Revenue-to-Cost ratios have been correctly determined in accordance with OEB policies and practices. Specific adjustments to cost allocation methodology and Revenue-to-Cost ratios as a result of the IR Responses and the Settlement Proposal are summarized below.

An update copy of the Cost Allocation Model is included in Attachment G of this Settlement Proposal and has also been filed through the OEB's e-filing service.

The resulting Revenue-to-Cost ratios are presented in Table 23 below.

TABLE 23: SUMMARY OF 2016 REVENUE TO COST RATIOS

RATE CLASS	APPLICATION	IR RESPONSES	VARIANCE	SETTLEMENT	VARIANCE
	(A)	(B)	(C) = (B) - (A)	(D)	(E) = (D) - (B)
Residential	93%	92%	-1%	93%	1%
General Service <50kW	116%	118%	2%	119%	1%
General Service 50 - 999 kW	120%	120%	0%	120%	0%
General Service 1,000 to 4,999 kW	100%	100%	0%	100%	0%
Unmetered Scattered Loads	120%	120%	0%	115%	-5%
Sentinel Lights	100%	80%	-20%	80%	0%
Street Lights	120%	120%	0%	120%	0%

It should be noted that in the above table, the “Settlement” column represents the Cost Allocation methodology applied in WNP’s repose to interrogatory 7-VECC-40 as well as incorporating the changes agreed as a consequence of the settlement proposal (for example revisions to load forecast volume, OM&A adjustment and revenue requirement).

As a result of this Settlement Proposal, the Revenue-to-Cost ratios proposed in Table 23 are consistent for 2016 through to the next rebasing application.

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

COMPLETE SETTLEMENT

The Parties accept the evidence of WNP that all elements of the rate design have been correctly determined in accordance with OEB policies and practices. Specific adjustments to the rate design as a result of the IR Responses and the Settlement Proposal are summarized immediately below and are described in detail in the specified sections further below:

- Issue 3.3.1 – Adjustment of Fixed / Variable split for Four Rate Classes
- Issue 3.3.2 – Residential Rate Design
- Issue 3.3.3 – Tariff Sheet Updates

The resulting distribution rates are presented in Table 24 below.

TABLE 24: MAY 1, 2016 DISTRIBUTION RATES

RATE CLASS	Fixed Rate	Billing Determinant	Variable Rate
Residential	$ 23.97	kWh	$ 0.0153
General Service <50kW	$ 41.71	kWh	$ 0.0179
General Service 50 - 999 kW	$ 275.90	kW	$ 2.6315
General Service 1,000 to 4,999 kW	$2,254.94	kW	$ 3.0505
Unmetered Scattered Loads	$ 28.33	kWh	$ 0.0156
Sentinel Lights	$ 7.38	kW	$27.3041
Street Lights	$ 1.60	kW	$ 1.7664

Evidence References:

Application dated November 2nd 2015:

- Exhibit 7 / Tab 1 / Schedule 1
- Exhibit 7 / Tab 2 / Schedule 2
- Exhibit 7 / Tab 3 / Schedule 3
- Exhibit 8 / Tab 1 / Schedule 3

IR Responses dated January 27th 2015:

- IR 7-VECC-38, pages 203-204
- IR 7-VECC-40, pages 206-207
- IR 7-VECC-41, page 208
- IR 7-Energy Probe-34, page 209
- IR 7-Energy Probe-35, page 210
- IR 8-Staff-48, pages 211-223

- IR 8-Staff-50, page 225
- IR 8-VECC-42, page 228

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

3.3.1 Adjustment of Fixed / Variable Split for Four Rate Classes

For the purposes of settlement, the Parties have agreed that four rate classes (General Service <50kW, Unmetered Scattered Load, Sentinel Lights and Street Lights) should maintain their current fixed / variable split. For the remaining rate classes (Residential, General Service 50-999kW and General Service 1,000 – 4,999kW) the proposed fixed/variable split as presented in the interrogatories are accepted.

The table below summarizes the proposed fixed/variable split for 2016 rates as a result of the IRs and the settlement conference.

TABLE 25: PROPOSED FIXED / VARIABLE SPLIT FOR 2016 RATES

RATE CLASS	Existing Fixed / Variable Split		Proposed Fixed / Variable Split	
	Fixed	Variable	Fixed	Variable
Residential	58.72%	41.28%	69.04%	30.96%
General Service <50kW	51.62%	48.38%	51.62%	48.38%
General Service 50 - 999 kW	45.46%	54.54%	54.22%	45.78%
General Service 1,000 to 4,999 kW	39.77%	60.23%	29.05%	70.95%
Unmetered Scattered Loads	83.10%	16.90%	83.10%	16.90%
Sentinel Lights	59.34%	40.66%	59.34%	40.66%
Street Lights	83.16%	16.84%	83.16%	16.84%

Evidence References:

Application dated November 2nd 2015:

- Exhibit 8 / Tab 1 / Schedule 1
- Exhibit 8 / Tab 1 / Schedule 2
- Exhibit 8 / Tab 1 / Schedule 3

IR Responses dated January 27th 2015:

- IR 8-VECC-42, page 228

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

3.3.2 – Residential Rate Design

Under the OEB's new Policy entitled "A New Distribution Rate Design for Residential Electricity Customers" (EB-2012-0140), distributors are required to structure Residential distribution rates so that all costs for distribution service are collected through a fixed monthly charge within four years (i.e. by 2019).

The Parties agree to the proposed implementation of a fixed monthly distribution charge for Residential customers over four years.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 8 / Tab 1 / Schedule 2
- Exhibit 8 / Tab 1 / Schedule 3
- Exhibit 8 / Tab 1 / Schedule 16

IR Responses dated January 27th 2015:

- IR 8-Staff-50, page 225

Clarification Question Responses dated February 8th 2016:

- None

Other:

- The OEB's Report on A New Distribution Rate Design for Residential Electricity Customers dated April 2, 2015, EB-2012-0410.

Supporting Parties:

All

3.3.3 Tariff Sheet Updates

The Parties agree to update the proposed tariff sheets to reflect the adjustments from the IR Responses and the Settlement Proposal. These include:

- Update of the Wholesale Market Service Rate from $0.0044/kWh to $0.0036/kWh effective January 1, 2016; and
- Addition of the Ontario Electricity Support Program Charge of $0.0011/kWh effective January 1, 2016.

Copies of the updated Tariff sheets have been included in Attachment A of this Settlement Proposal.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 8 – Appendix 8B: WNP's Proposed Schedule
- 2016 Filing Requirements – Chapter 2 Appendices / worksheet App.2-Z: Tariff
- 2016 Filing Requirements – Chapter 2 Appendices / worksheet App.2-W: Bill Impacts

IR Responses dated January 27th 2015:

- IR 8-Staff-48, pages 211-223

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

3.4 Are the proposed Retail Transmission Service Rates and Low Voltage service rates appropriate?

COMPLETE SETTLEMENT

The Parties accept the evidence of WNP that all elements of the Retail Transmission Service Rates and Low Voltage Service Rates have been correctly determined in accordance with OEB policies and practices. Specific adjustments to the rates as a result of the IR Responses and the Settlement Proposal are summarized immediately below and are described in detail in the specified sections further below:

- Issue 3.4.1 – Retail Transmission Service Rates
- Issue 3.4.2 – Low Voltage Service Rates

3.4.1 Retail Transmission Service Rates

As per WNP response to interrogatory 8-Staff-51, the Applicant updated the Proposed RTSR-Network and Proposed RTSR- Connection rates as a result of the OEB issuing the 2016 Uniform Transmission Rates (UTR) as per Decision and Order EB-2015-0311: "2016 Uniform Transmission Rates" (January 14th 2016).

The Parties have agreed to the RTSR rates presented in Table 26 below:

TABLE 26: RTSR NETWORK AND CONNECTION RATES

RATE CLASS	Proposed RTSR-Network	Proposed RTSR-Connection
Residential	$0.0067	$0.0045
General Service Less Than 50 kW	$0.0062	$0.0038
General Service 50 to 999 kW	$2.5509	$1.5344
General Service 1,000 to 4,999 kW	$2.7094	$1.6821
Street Lighting	$1.9237	$1.1863
Sentinel Lighting	$1.9334	$1.2111
Unmetered Scattered Load	$0.0062	$0.0038

A copy of the OEB's RTSR Model has been included in Attachment H of this Settlement Proposal and has also been filed through the OEB's e-filing service.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 8 / Tab 1 / Schedule 4

IR Responses dated January 27th 2015:

- IR 2-Staff-12, pages 35-36
- IR 8-Staff-51, pages 226-227
- IR 8-VECC-43, page 229
- IR 8-Energy Probe-36, page 232

Clarification Question Responses dated February 8th 2016:

- None

Other:

- 2016 Uniform Transmission Rate Decision and Order dated January 14, 2016, OEB File No. EB-2015-0311

Supporting Parties:

All

3.4.2 Low Voltage Service Rates

Subsequent to updates related to interrogatories and this Settlement Proposal, the Parties have agreed to the Low Voltage rates presented in Table 27 below.

TABLE 27: LOW VOLTAGE SERVICE RATES

RATE CLASS	Allocated LV Charges	Unit	2016 Load Forecast	LV Rate
Residential	$80,629	kWh	27,408,200	$0.0029
General Service Less Than 50 kW	$30,631	kWh	12,494,682	$0.0025
General Service 50 to 999 kW	$43,155	kWh	43,362	$0.9952
General Service 1,000 to 4,999 kW	$118,163	kWh	108,301	$1.0911
Street Lighting	$1,535	kWh	1,995	$0.7695
Sentinel Lighting	$51	kWh	65	$0.7856
Unmetered Scattered Load	$7	kWh	3,024	$0.0025
	$274,171		**40,059,629**	

Evidence References:

Application dated November 2nd 2015:

- Exhibit 8 / Tab 1 / Schedule 11

IR Responses dated January 27th 2015:

- IR 8-Energy Probe-37, pages 233-235

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

4 ACCOUNTING

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

COMPLETE SETTLEMENT

The Parties accept the evidence of WNP that all impacts of changes to accounting standards, policies, estimates and adjustments have been properly identified and recorded in accordance with the OEB's policies and properly reflected in rates.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 9 / Tab 1 / Schedule 1
- Exhibit 9 / Tab 1 / Schedule 2
- Exhibit 9 / Tab 1 / Schedule 3
- Exhibit 9 / Tab 1 / Schedule 4
- Exhibit 9 / Tab 1 / Schedule 5
- Exhibit 9 / Tab 1 / Schedule 6
- Exhibit 9 / Tab 1 / Schedule 7
- Exhibit 9 / Tab 1 / Schedule 8
- Exhibit 9 / Tab 1 / Schedule 9
- Exhibit 9 / Tab 1 / Schedule 10
- Exhibit 9 / Tab 1 / Schedule 11
- Exhibit 9 / Tab 4 / Schedule 1
- Exhibit 9 / Tab 4 / Schedule 2
- Exhibit 9 – Appendix 9A: EDDVAR Continuity Schedule

IR Responses dated January 27th 2015:

- IR 9-Energy Probe-38, page 236

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

4.2 Are the Applicant's proposals for the Deferral and Variance accounts, including the balances in existing accounts and their disposition as well as the continuation of existing accounts, appropriate?

COMPLETE SETTLEMENT

The Parties accept the evidence of WNP that all elements of the deferral and variance accounts, including the balances in the existing accounts and their disposition on a harmonized basis commencing May 1, 2016, as well as the continuation of existing accounts. Specific adjustments to the deferral and variance accounts as a result of the IR Responses and the Settlement Proposal are summarized immediately below and are described in detail in the specified sections further below:

- Issue 4.2.1 - LRAM & LRAMVA Disposition
- Issue 4.2.2 - LRAMVA Baseline
- Issue 4.2.3 - OPEBs Deferral Account
- Issue 4.2.4 - Capital Project – 2nd line feeder (Deferral Account)

Table 28 below summarizes the amounts for disposition and associated rate riders by rate class.

TABLE 28: DVA RATE RIDERS

RATE CLASS	Billing Determinant	Group One	Group One Non RRP	Group Two	LRAMVA
Total Amount		$22,445	$153,328	$51,218	$11,761
Residential	kWh	$0.0003	$0.0021	$0.34	$0.0001
General Service <50kW	kWh	$0.0002	$0.0021	$0.0005	$0.0006
General Service 50 - 999 kW	kW	$0.0623	$0.6793	$0.1577	$0.0004
General Service 1,000 to 4,999 kW	kW	$0.0898	$0.9787	$0.2272	$0.0087
Unmetered Scattered Loads	kWh	$0.0002	$0.0000	$0.0005	($0.0005)
Sentinel Lights	kW	$0.0686	$0.7449	$0.1729	($1.0082)
Street Lights	kW	$0.0699	$0.7615	$0.1768	($0.1947)

Note: For Residential customers, Group 2 Accounts are to be disposed on a per customer basis (not volumetric) as per OEB's letter issued July 16th 2015 regarding implementation of transition to fully fixed distribution charges.

A copy of the DVA Continuity (EDDVAR) Model has been filed through the OEB's e-filing service.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 9 / Tab 4 / Schedule 1
- Exhibit 9 – Appendix 9A: EDDVAR Continuity Schedule

IR Responses dated January 27th 2015:

- IR 9-Energy Probe-38, page 236

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

4.2.1 LRAM & LRAMVA Disposition Calculation

The Parties agree to the LRAM and LRAMVA calculations and the resulting deferral disposition balances as presented in Table 29 below.

Table 29: LRAM/LRAMVA Rate Rider

RATE CLASS	Billing Determinant	Balance	Rate Rider
Residential	kWh	$3,804.04	$0.0001
General Service <50kW	kWh	$7,453.92	$0.0006
General Service 50 - 999 kW	kW	$17.19	$0.0004
General Service 1,000 to 4,999 kW	kW	$941.43	$0.0087
Unmetered Scattered Loads	kWh	($1.42)	($0.0005)
Sentinel Lights	kW	($65.56)	($1.0082)
Street Lights	kW	($388.30)	($0.1947)
Total Amount		**$11,761.29**	

Evidence References:

Evidence References:

Application dated November 2nd 2015:

- Exhibit 9 / Tab 4 / Schedule 1
- Exhibit 9 – Appendix 9A: EDDVAR Continuity Schedule
- WNP LRAM Model filed with Application

IR Responses dated January 27th 2015:

- IR 3-Staff-39, pages 109-110
- IR 3-VECC-19, pages 123-126

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

4.2.2 LRAMVA Baseline

As per WNP's response to interrogatory 3-VECC-19, the 2016 LRAMVA Baseline should be 1,966,667 kWh calculated by 2015 persistence savings flowing into 2016 plus 2016 actual savings. This is based on the following assumptions:

a) Persistence is on a 1.0 basis, not reduced or adjusted (as reported by the OPA / IESO in the 2011-2014 CDM Program) and;
b) Persistence information will be made available to LDC's from the governing authorized body, the IESO, to enable LDC's to measure LRAMVA correctly.
   Presently, IESO reports released to LDCs for the 2015-2020 Conservation First Framework contain only what savings have been made during the calendar year and do not provide persistence savings from prior years. Under the rules of the Conservation First Framework, persistence savings from prior years of the program cannot be recognized for targeting reporting purposes. (For instance, 2016 reports do not show persistence savings from 2015.)

The Parties agreed that WNP's LRAMVA Baseline of 1,966,667 kWh for 2016 is acceptable and OEB Staff have confirmed that reports will be available from the IESO, as the body responsible for confirming CDM savings, of the persisting savings for the 2015 – 2020 period from prior years' CDM programs. Should this information not be available, then WNP will require direction from the OEB on how to obtain, measure and record LRAMVA Baseline energy savings for 2016 and beyond.

For the purposes of settlement, the Parties agree to the proposed LRAMVA baseline as presented in Table 30 below based on WNP's annual CDM target of 983,333 kWh of energy savings in 2015 plus 983,333 kWh of energy savings in 2016 on the provision that persistence reporting is available as noted above.

TABLE 30: 2016 LRAMVA BASELINE CALCULATION

Year 2015

Customer Class	Share	Annual CDM Target (kWh)	Annual CDM Target (kW)	kW:kWh Ratio	Monthly CDM Target (kWh)	Monthly CDM Target (kW)
Residential	25%	248,550			20,712	
General Service < 50 kW	12%	113,307			9,442	
General Service 50 to 999 kW	13%	129,396	399	0.31%	10,783	33
General Service 1000 to 4,999 kW	50%	492,080	1,053	0.21%	41,007	88
Street Lights	0%	0				
Sentinel Lights	0%	0				
Unmetered Loads	0%	0				
Annual Total	**100%**	**983,333**	**1,452**			

Year 2016

Customer Class	Share	Annual CDM Target (kWh)	Annual CDM Target (kW)	kW:kWh Ratio	Monthly CDM Target (kWh)	Monthly CDM Target (kW)
Residential	25%	248,550			20,712	
General Service < 50 kW	12%	113,307			9,442	
General Service 50 to 999 kW	13%	129,396	399	0.31%	10,783	33
General Service 1000 to 4,999 kW	50%	492,080	1,053	0.21%	41,007	88
Street Lights	0%	0				
Sentinel Lights	0%	0				
Unmetered Loads	0%	0				
Annual Total	**100%**	**983,333**	**1,452**			

Evidence References:

Application dated November 2nd 2015:

- Exhibit 9 / Tab 4 / Schedule 1
- Exhibit 9 – Appendix 9A: EDDVAR Continuity Schedule

IR Responses dated January 27th 2015:

- IR 3-VECC-19, pages 123-126

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

4.2.3 OPEBs (Deferral / Variance Account)

Consistent with other recent Settlement Proposals approved by the OEB (for example Guelph Hydro: EB-2015-0073 and Waterloo North Hydro EB-2015-0108), the Parties agree that WNP will establish a new deferral account for the purpose of recording the difference in revenue requirement each year, starting in the 2016 Test Year, between both the capitalized and OM&A components of OPEBs accounted for using a forecasted cash basis (as to be reflected in rates if this Settlement Proposal is accepted by the OEB) and both capitalized and OM&A components of OPEBs accounted for using a forecasted accrual basis. Carrying charges will not apply to this deferral account. If the OEB determines that LDCs must include in rates OPEBs accounted for using a forecasted cash basis, WNP will seek to discontinue this account without seeking disposition of the amounts recorded in this account. If the OEB determines that LDCs should recover OPEBs in rates using a forecasted accrual accounting methodology, the Parties agree that WNP may seek disposition of this account to dispose the amounts recorded in its next cost of service rate application. WNP will propose a disposition period over which the account should be disposed depending on the quantum in the account and the potential rate impacts at the time.

A draft accounting order for this account is included in Attachment J to this Settlement Proposal.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 4 / Tab 3 / Schedule 1, page 35
- Exhibit 4 – Appendix 4H: Actuarial Report

IR Responses dated December 18, 2015:

- IR 4-Staff-45, page 152
- IR 4-Energy Probe-22, page 180

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

4.2.4 Capital Project – 2nd line feeder (Deferral Variance Account)

As per Issue 1.1, the Parties agree that WNP will establish a new deferral account for the purpose of recording the difference in revenue requirement each year, starting in the 2016 Test Year, between the total estimated cost of the construction of the second line feeder to Mount Forest (HONI work [estimate $931,261] plus WNP work [PME Meter and pole-line construction work [estimate $460,000]) for disposal / recovery in a subsequent IRM application.

A draft accounting order for this account is included in Attachment K to this Settlement Proposal.

Evidence References:

Application dated November 2nd 2015:

- Exhibit 2 / Tab 1 / Schedule 3
- Exhibit 2 / Tab 1 / Schedule 4
- Exhibit 2 / Tab 2 / Schedule 1
- Exhibit 2 / Tab 2 / Schedule 2
- Exhibit 2 - Appendix 5A: WNP's Distribution System Plan
- Section 5.4.5.3 – Special Projects
- Exhibit 2 - Appendix 5A: WNP's Distribution System Plan
    - Section 5.0 –Appendix 5D: Hydro One Networks Inc. Town of Mount Forest Supply Study
    - Section 5.0 –Appendix 5E: Stakeholder letters supporting 2nd feeder
    - Section 5.0 –Appendix 5F: 3rd Party Substation Assessment Study

IR Responses dated January 27th 2015:

- IR 2-Staff-7, pages 25-29
- IR 2-Staff-25, page 61
- IR 2-VECC-13, pages 84-85

Clarification Question Responses dated February 8th 2016:

- None

Supporting Parties:

All

5 ATTACHMENTS

A. Proposed May 1, 2016 Tariff of Rates and Charges

Residential Customer:

Wellington North Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

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

EB-2015-0110

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to Customers residing in residential dwelling units. Energy is generally supplied as single phase, 3-wire, 60-Hertz, having a nominal voltage of 120/240 Volts. 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

Monthly Service Charge	$	23.97
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0153
Low Voltage Service Rate	$/kWh	0.0029
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	$/kWh	0.0021
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	$	0.3416
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	$/kWh	0.0001
RTSR - Network	$/kWh	0.0067
RTSR - Line and Transformation Connection	$/kWh	0.0045

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Ontario Electricity Support Program (OESP)	$/kWh	0.0011

General Service <50kW Customer:

Wellington North Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

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

EB-2015-0110

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to customers in General Service buildings with a connected load less than 50 kW, and Town Houses and Condominiums that require centralized bulk metering. General Service buildings are defined as buildings that are used for purposes other than single-family 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.

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MONTHLY RATES AND CHARGES - Delivery Component

Monthly Service Charge	$	41.71
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0179
Low Voltage Service Rate	$/kWh	0.0025
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	$/kWh	0.0021
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	$/kWh	0.0005
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	$/kWh	0.0006
RTSR - Network	$/kWh	0.0062
RTSR - Line and Transformation Connection	$/kWh	0.0038

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Ontario Electricity Support Program (OESP)	$/kWh	0.0011

General Service 50 – 999 kW Customer:

Wellington North Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

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

EB-2015-0110

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,000 kW. Further servicing details are available in the distributor's Conditions of Service

APPLICATION

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

Monthly Service Charge	$	275.90
Distribution Volumetric Rate	$/kW	2.6315
Low Voltage Service Rate	$/kW	0.9952
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	$/kW	0.0623
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	$/kW	0.6793
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	$/kW	0.1577
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	$/kW	0.0004
RTSR - Network	$/kW	2.5509
RTSR - Line and Transformation Connection	$/kW	1.5344

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Ontario Electricity Support Program (OESP)	$/kWh	0.0011

General Service 1,000 – 4,999 kW Customer:

Wellington North Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

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

EB-2015-0110

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 1,000 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
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MONTHLY RATES AND CHARGES - Delivery Component

Monthly Service Charge	$	2,254.94
Distribution Volumetric Rate	$/kW	3.0505
Low Voltage Service Rate	$/kW	1.0911
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	$/kW	0.0898
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	$/kW	0.9787
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	$/kW	0.2272
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	$/kW	0.0087
RTSR - Network	$/kW	2.7094
RTSR - Line and Transformation Connection	$/kW	1.6821

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Ontario Electricity Support Program (OESP)	$/kWh	0.0011

Unmetered Scattered Load Customer:

Wellington North Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

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

EB-2015-0110

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, decorative street lighting, billboards, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer

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

Monthly Service Charge	$	28.33
Distribution Volumetric Rate	$	0.0156
Low Voltage Service Rate	$/kWh	0.0025
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	$/kWh	0.0000
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	$/kWh	0.0005
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	$/kWh	(0.0005)
RTSR - Network	$/kWh	0.0062
RTSR - Line and Transformation Connection	$/kWh	0.0038

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Ontario Electricity Support Program (OESP)	$/kWh	0.0011

Sentinel Lighting Customer:

Wellington North Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

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

EB-2015-0110

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts for unmetered lighting loads supplied to sentinel lights. 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

Monthly Service Charge	$	7.38
Distribution Volumetric Rate	$/kW	27.3041
Low Voltage Service Rate	$/kW	0.7856
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	$/kW	0.0686
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	$/kW	0.7449
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	$/kW	0.1729
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	$/kW	(1.0082)
RTSR - Network	$/kW	1.9334
RTSR - Line and Transformation Connection	$/kW	1.2111

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Ontario Electricity Support Program (OESP)	$/kWh	0.0011

Street Lighting Customer:

Wellington North Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

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

EB-2015-0110

STREET LIGHTING SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

Monthly Service Charge	$	1.60
Distribution Volumetric Rate	$/kW	1.7664
Low Voltage Service Rate	$/kW	0.7695
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	$/kW	0.0699
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	$/kW	0.7615
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	$/kW	0.1768
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	$/kW	(0.1947)
RTSR - Network	$/kW	1.9237
RTSR - Line and Transformation Connection	$/kW	1.1863

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Ontario Electricity Support Program (OESP)	$/kWh	0.0011

MicroFIT Customer:

Wellington North Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

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

EB-2015-0110

Microfit Generation 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 a wholesale market price, as applicable.

It should be noted that this schedule does 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 HST.

MONTHLY RATES AND CHARGES - Delivery Component

Monthly Service Charge	$	15.69

Allowances and Specific Service Charges:

Wellington North Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

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

EB-2015-0110

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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

Notification charge Notification charge	$	15.00
Account History	$	15.00
Returned cheque (plus bank charges)	$	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
Collection of account charge – no disconnection - during regular business hours	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Interval Meter Load Management Tool Charge $/month	$	50.00
Service call – customer owned equipment	$	30.00
Service Call – Customer-owned Equipment – After Regular Hours	$	165.00
Temporary Service – Install & remove – overhead – no transformer	$	500.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

Retailer Service Charges and Loss Factors:

Wellington North Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

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

EB-2015-0110

RETAIL SERVICE CHARGES (if applicable)

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

Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0656
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0549

B. Bill Impacts

Residential RPP Customer – Monthly Consumption of 800 kWh:

Customer Class:	Residential TOU	
RPP / Non-RPP:	RPP	
Consumption	800	kWh
Demand	-	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.49	1	$ 18.49	$ 23.97	1	$ 23.97	$ 5.48	29.64%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.8800	1	$ 0.88	$ -	1	$ -	-$ 0.88	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0185	800	$ 14.80	$ 0.0153	800	$ 12.24	-$ 2.56	-17.31%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0009	800	$ 0.72	$ -	800	$ -	-$ 0.72	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.89			$ 36.21	**$ 1.32**	**3.78%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0003	800	$ 0.21	$ 0.21	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0021	800	$ 1.68	$ 1.68	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	Monthly		800	$ -	$ 0.3416	1	$ 0.34	$ 0.34	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0001	800	$ 0.11	$ 0.11	
Low Voltage Service Charge	per kWh	$ 0.0018	800	$ 1.44	$ 0.0029	800	$ 2.35	$ 0.91	63.43%
Line Losses on Cost of Power	per kWh	$ 0.1021	57	$ 5.85	$ 0.1021	52	$ 5.36	-$ 0.49	-8.38%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 42.97**			**$ 47.05**	**$ 4.08**	**9.49%**
RTSR - Network	per kWh	$ 0.0067	857	$ 5.74	$ 0.0067	852	$ 5.74	-$ 0.01	-0.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	857	$ 3.60	$ 0.0045	852	$ 3.87	$ 0.27	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 52.31**			**$ 56.65**	**$ 4.34**	**8.29%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	857	$ 3.77	$ 0.0036	852	$ 3.07	-$ 0.70	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	857	$ 1.11	$ 0.0013	852	$ 1.11	-$ 0.01	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh				$ -				
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	857	$ 0.94	$ 0.0011	852	$ 0.94		0.00%
TOU - Off Peak	per kWh	$ 0.0800	512	$ 40.96	$ 0.0800	512	$ 40.96	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1220	144	$ 17.57	$ 0.1220	144	$ 17.57	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1610	144	$ 23.18	$ 0.1610	144	$ 23.18	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 140.11**			**$ 143.73**	**$ 3.62**	**2.59%**
HST		13%		$ 18.21	13%		$ 18.68	$ 0.47	2.59%
Total Bill (including HST)				$ 158.32			$ 162.41	$ 4.09	2.59%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 158.32**			**$ 162.41**	**$ 4.09**	**2.59%**

Residential Non-RPP Customer – Monthly Consumption of 800 kWh:

Customer Class:	**Residential Retailer**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**800** kWh
Demand	- kW
Current Loss Factor	**1.0716**
Proposed/Approved Loss Factor	**1.0656**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 18.49	1	$ 18.49	$ 23.97	1	$ 23.97	$ 5.48	29.64%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.8800	1	$ 0.88		1	$ -	-$ 0.88	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0185	800	$ 14.80	$ 0.0153	800	$ 12.24	-$ 2.56	-17.31%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0009	800	$ 0.72		800	$ -	-$ 0.72	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.89			$ 36.21	**$ 1.32**	**3.78%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0003	800	$ 0.21	$ 0.21	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0021	800	$ 1.68	$ 1.68	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	Monthly		800	$ -	$ 0.3416	1	$ 0.34	$ 0.34	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0001	800	$ 0.11	$ 0.11	
Low Voltage Service Charge	per kWh	$ 0.0018	800	$ 1.44	$ 0.0029	800	$ 2.35	$ 0.91	63.43%
Line Losses on Cost of Power	per kWh	$ 0.0860	57	$ 4.93	$ 0.0860	52	$ 4.51	-$ 0.41	-8.38%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 42.05**			**$ 46.20**	**$ 4.16**	**9.89%**
RTSR - Network	per kWh	$ 0.0067	857	$ 5.74	$ 0.0067	852	$ 5.74	-$ 0.01	-0.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	857	$ 3.60	$ 0.0045	852	$ 3.87	$ 0.27	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 51.39**			**$ 55.81**	**$ 4.42**	**8.59%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	857	$ 3.77	$ 0.0036	852	$ 3.07	-$ 0.70	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	857	$ 1.11	$ 0.0013	852	$ 1.11	-$ 0.01	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh		800	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	857	$ 0.94	$ 0.0011	852	$ 0.94		0.00%
Non-RPP Retailer Avg. Price		$ 0.0860	800	$ 68.80	$ 0.0860	800	$ 68.80	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 167.23**			**$ 170.93**	**$ 3.70**	**2.21%**
HST		13%		$ 21.74	13%		$ 22.22	$ 0.48	2.21%
Total Bill (including HST)				$ 188.97			$ 193.15	$ 4.18	2.21%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 188.97**			**$ 193.15**	**$ 4.18**	**2.21%**

Residential RPP Customer (Low User) – Monthly Consumption of 310 kWh:

Customer Class:	Residential TOU (Low-user)	
RPP / Non-RPP:	RPP	
Consumption	310	kWh
Demand	-	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.49	1	$ 18.49	$ 23.97	1	$ 23.97	$ 5.48	29.64%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.8800	1	$ 0.88		1	$ -	-$ 0.88	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0185	310	$ 5.74	$ 0.0153	310	$ 4.74	-$ 0.99	-17.31%
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0009	310	$ 0.28		310	$ -	-$ 0.28	-100.00%
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
Sub-Total A (excluding pass through)				$ 25.38			$ 28.71	**$ 3.33**	**13.11%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0003	310	$ 0.08	$ 0.08	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0021	310	$ 0.65	$ 0.65	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	Monthly		310	$ -	$ 0.3416	1	$ 0.34	$ 0.34	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0001	310	$ 0.04	$ 0.04	
Low Voltage Service Charge	per kWh	$ 0.0018	310	$ 0.56	$ 0.0029	310	$ 0.91	$ 0.35	63.43%
Line Losses on Cost of Power	per kWh	$ 0.1021	22	$ 2.27	$ 0.1021	20	$ 2.08	-$ 0.19	-8.38%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.00**			**$ 33.61**	**$ 4.61**	**15.89%**
RTSR - Network	per kWh	$ 0.0067	332	$ 2.23	$ 0.0067	330	$ 2.22	-$ 0.00	-0.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	332	$ 1.40	$ 0.0045	330	$ 1.50	$ 0.10	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 32.62**			**$ 37.33**	**$ 4.71**	**14.43%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	332	$ 1.46	$ 0.0036	330	$ 1.19	-$ 0.27	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	332	$ 0.43	$ 0.0013	330	$ 0.43	-$ 0.00	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh		310	$ -					
Ontario Electricity Support Program (OESP)		$ 0.0011	332	$ 0.37	$ 0.0011	330	$ 0.36		0.00%
TOU - Off Peak	per kWh	$ 0.0800	198	$ 15.87	$ 0.0800	198	$ 15.87	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1220	56	$ 6.81	$ 0.1220	56	$ 6.81	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1610	56	$ 8.98	$ 0.1610	56	$ 8.98	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 66.79**			**$ 71.22**	**$ 4.43**	**6.63%**
HST		13%		$ 8.68	13%		$ 9.26	$ 0.58	6.63%
Total Bill (including HST)				$ 75.48			$ 80.48	$ 5.01	6.63%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 75.48**			**$ 80.48**	**$ 5.01**	**6.63%**

Residential Non RPP Customer (Low User) – Monthly Consumption of 310 kWh:

Customer Class:	Residential Retailer (Low user)
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	310 kWh
Demand	- kW
Current Loss Factor	1.0716
Proposed/Approved Loss Factor	1.0656
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.49	1	$ 18.49	$ 23.97	1	$ 23.97	$ 5.48	29.64%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.8800	1	$ 0.88		1	$ -	-$ 0.88	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0185	310	$ 5.74	$ 0.0153	310	$ 4.74	-$ 0.99	-17.31%
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0009	310	$ 0.28		310	$ -	-$ 0.28	-100.00%
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
Sub-Total A (excluding pass through)				$ 25.38			$ 28.71	**$ 3.33**	**13.11%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0003	310	$ 0.08	$ 0.08	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0021	310	$ 0.65	$ 0.65	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	Monthly		310	$ -	$ 0.3416	1	$ 0.34	$ 0.34	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0001	310	$ 0.04	$ 0.04	
Low Voltage Service Charge	per kWh	$ 0.0018	310	$ 0.56	$ 0.0029	310	$ 0.91	$ 0.35	63.43%
Line Losses on Cost of Power	per kWh	$ 0.1021	22	$ 2.27	$ 0.0860	20	$ 1.75	-$ 0.52	-22.86%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.00**			**$ 33.28**	**$ 4.28**	**14.76%**
RTSR - Network	per kWh	$ 0.0067	332	$ 2.23	$ 0.0067	330	$ 2.22	-$ 0.00	-0.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	332	$ 1.40	$ 0.0045	330	$ 1.50	$ 0.10	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 32.62**			**$ 37.00**	**$ 4.38**	**13.43%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	332	$ 1.46	$ 0.0036	330	$ 1.19	-$ 0.27	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	332	$ 0.43	$ 0.0013	330	$ 0.43	-$ 0.00	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh		310	$ -					
Ontario Electricity Support Program (OESP)		$ 0.0011	332	$ 0.37	$ 0.0011	330	$ 0.36		0.00%
Non-RPP Retailer Avg. Price		$ 0.0860	310	$ 26.66	$ 0.0860	310	$ 26.66	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 77.66**			**$ 81.76**	**$ 4.10**	5.28%
HST		13%		$ 10.10	13%		$ 10.63	$ 0.53	5.28%
Total Bill (including HST)				$ 87.76			$ 92.39	$ 4.64	5.28%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 87.76**			**$ 92.39**	**$ 4.64**	**5.28%**

General Service <50kW RPP Customer – Monthly Consumption of 2,000 kWh:

Customer Class:	General Service <50 kW	
RPP / Non-RPP:	RPP	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 39.25	1	$ 39.25	$ 41.71	1	$ 41.71	$ 2.46	6.27%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 1.8700	1	$ 1.87		1	$ -	-$ 1.87	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0168	2,000	$ 33.60	$ 0.0179	2,000	$ 35.71	$ 2.11	6.27%
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0008	2,000	$ 1.60		2,000	$ -	-$ 1.60	-100.00%
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 76.32			$ 77.42	**$ 1.10**	**1.44%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0002	2,000	$ 0.43	$ 0.43	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0021	2,000	$ 4.19	$ 4.19	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0005	2,000	$ 0.97	$ 0.97	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0006	2,000	$ 1.19	$ 1.19	
Low Voltage Service Charge	per kWh	$ 0.0015	2,000	$ 3.00	$ 0.0025	2,000	$ 4.90	$ 1.90	63.43%
Line Losses on Cost of Power	per kWh	$ 0.1021	143	$ 14.63	$ 0.1021	131	$ 13.40	-$ 1.23	-8.38%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 94.74**			**$ 103.30**	**$ 8.56**	**9.03%**
RTSR - Network		$ 0.0062	2,143	$ 13.29	$ 0.0062	2,131	$ 13.27	-$ 0.02	-0.11%
RTSR - Line and Transformation Connection		$ 0.0035	2,143	$ 7.50	$ 0.0038	2,131	$ 8.05	$ 0.55	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 115.53**			**$ 124.62**	**$ 9.10**	**7.87%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2,143	$ 9.43	$ 0.0036	2,131	$ 7.67	-$ 1.76	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,143	$ 2.79	$ 0.0013	2,131	$ 2.77	-$ 0.02	-0.56%
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	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
Ontario Electricity Support Program (OESP)		$ 0.0011	2,143	$ 2.36	$ 0.0011	2,131	$ 2.34		0.00%
TOU - Off Peak		$ 0.0800	1,280	$ 102.40	$ 0.0800	1,280	$ 102.40	$ -	0.00%
TOU - Mid Peak		$ 0.1220	360	$ 43.92	$ 0.1220	360	$ 43.92	$ -	0.00%
TOU - On Peak		$ 0.1610	360	$ 57.96	$ 0.1610	360	$ 57.96	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 348.63**			**$ 355.94**	**$ 7.31**	**2.10%**
HST		13%		$ 45.32	13%		$ 46.27	$ 0.95	2.10%
Total Bill (including HST)				$ 393.95			$ 402.21	$ 8.26	2.10%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 393.95**			**$ 402.21**	**$ 8.26**	**2.10%**

General Service <50 kW Non-RPP Customer – Monthly Consumption of 2,000 kWh:

Customer Class:	**General Service <50 kW**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**2,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0716**	
Proposed/Approved Loss Factor	**1.0656**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 39.25	1	$ 39.25	$ 41.71	1	$ 41.71	$ 2.46	6.27%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 1.8700	1	$ 1.87		1	$ -	-$ 1.87	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0168	2,000	$ 33.60	$ 0.0179	2,000	$ 35.71	$ 2.11	6.27%
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0008	2,000	$ 1.60		2,000	$ -	-$ 1.60	-100.00%
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 76.32			$ 77.42	**$ 1.10**	**1.44%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0002	2,000	$ 0.43	$ 0.43	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0021	2,000	$ 4.19	$ 4.19	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0005	2,000	$ 0.97	$ 0.97	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0006	2,000	$ 1.19	$ 1.19	
Low Voltage Service Charge	per kWh	$ 0.0015	2,000	$ 3.00	$ 0.0025	2,000	$ 4.90	$ 1.90	63.43%
Line Losses on Cost of Power	per kWh	$ 0.0860	143	$ 12.32	$ 0.0860	131	$ 11.28	-$ 1.03	-8.38%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 92.43**			**$ 101.18**	**$ 8.75**	**9.47%**
RTSR - Network	per kWh	$ 0.0062	2,143	$ 13.29	$ 0.0062	2,131	$ 13.27	-$ 0.02	-0.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0035	2,143	$ 7.50	$ 0.0038	2,131	$ 8.05	$ 0.55	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 113.21**			**$ 122.51**	**$ 9.29**	**8.21%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2,143	$ 9.43	$ 0.0036	2,131	$ 7.67	-$ 1.76	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,143	$ 2.79	$ 0.0013	2,131	$ 2.77	-$ 0.02	-0.56%
Standard Supply Service Charge	per kWh	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
Ontario Electricity Support Program (OESP)		$ 0.0011	2,143	$ 2.36	$ 0.0011	2,131	$ 2.34		0.00%
Non-RPP Retailer Avg. Price		$ 0.0860	2,000	$ 172.00	$ 0.0860	2,000	$ 172.00	$ -	0.00%
Average IESO Wholesale Market Price		$ 0.0906	2,000	$ 181.20	$ 0.0906	2,000	$ 181.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 416.44**			**$ 423.94**	**$ 7.50**	**1.80%**
HST		13%		$ 54.14	13%		$ 55.11	$ 0.98	1.80%
Total Bill (including HST)				$ 470.57			$ 479.06	$ 8.48	1.80%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 470.57**			**$ 479.06**	**$ 8.48**	**1.80%**

General Service 50 – 999 kW Non-RPP Customer – Monthly Demand of 106 kW:

Customer Class:	General Service 50-999kW	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	38,217	kWh
Demand	106	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 275.90	1	$ 275.90	$ 275.90	1	$ 275.90	$ -	0.00%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 13.1500	1	$ 13.15		1	$ -	-$ 13.15	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 3.6643	106	$ 388.42	$ 2.6315	106	$ 278.94	-$ 109.47	-28.18%
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kW	$ 0.1746	106	$ 18.51		106	$ -	-$ 18.51	-100.00%
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
Sub-Total A (excluding pass through)				$ 695.97			$ 554.84	**-$ 141.13**	**-20.28%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kW		106	$ -	$ 0.0623	106	$ 6.61	$ 6.61	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kW		106	$ -	$ 0.6793	106	$ 72.01	$ 72.01	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kW		106	$ -	$ 0.1577	106	$ 16.72	$ 16.72	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kW		106	$ -	$ 0.0004	106	$ 0.04	$ 0.04	
Low Voltage Service Charge	per kW	$ 0.6050	106	$ 64.13	$ 0.9952	106	$ 105.50	$ 41.37	64.50%
Line Losses on Cost of Power	per kW	$ -	-	$ -	$ -	-	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 760.10**			**$ 755.71**	**-$ 4.39**	**-0.58%**
RTSR - Network	per kW	$ 2.5395	106	$ 269.19	$ 2.5509	106	$ 270.40	$ 1.21	0.45%
RTSR - Line and Transformation Connection	per kW	$ 1.4209	106	$ 150.62	$ 1.5344	106	$ 162.64	$ 12.03	7.99%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,179.91**			**$ 1,188.75**	**$ 8.84**	**0.75%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	40,953	$ 180.19	$ 0.0036	40,724	$ 146.61	-$ 33.59	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	40,953	$ 53.24	$ 0.0013	40,724	$ 52.94	-$ 0.30	-0.56%
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	38,217	$ 267.52	$ 0.0070	38,217	$ 267.52	$ -	0.00%
Ontario Electricity Support Program (OESP)		$ 0.0011	40,953	$ 45.05	$ 0.0011	40,724	$ 44.80		0.00%
TOU - Off Peak				$ -			$ -	$ -	
TOU - Mid Peak				$ -			$ -	$ -	
TOU - On Peak				$ -			$ -	$ -	
Non-RPP Retailer Avg. Price				$ -			$ -	$ -	
Average IESO Wholesale Market Price		$ 0.0906	40,953	$ 3,710.37	$ 0.0906	40,724	$ 3,689.60	-$ 20.77	-0.56%
Total Bill on Average IESO Wholesale Market Price				**$ 5,436.53**			**$ 5,390.46**	**-$ 46.07**	**-0.85%**
HST		13%		$ 706.75	13%		$ 700.76	-$ 5.99	-0.85%
Total Bill (including HST)				$ 6,143.28			$ 6,091.22	-$ 52.06	-0.85%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 6,143.28**			**$ 6,091.22**	**-$ 52.06**	**-0.85%**

General Service 1,000 – 4,999 kW Non-RPP Customer – Monthly Demand of 1,476 kW:

Customer Class:	General Service 1000-4999 kW	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	746,695	kWh
Demand	1,476	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 2,254.94	1	$ 2,254.94	$ 2,254.94	1	$ 2,254.94	$ -	0.00%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 107.4600	1	$ 107.46		1	$ -	-$ 107.46	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.8921	1,476	$ 2,792.74	$ 3.0505	1,476	$ 4,502.50	$ 1,709.76	61.22%
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kW	$ 0.0902	1,476	$ 133.14		1,476	$ -	-$ 133.14	-100.00%
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
Sub-Total A (excluding pass through)				$ 5,288.27			$ 6,757.44	**$ 1,469.17**	**27.78%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kW		1,476	$ -	$ 0.0898	1,476	$ 132.51	$ 132.51	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kW		1,476	$ -	$ 0.9787	1,476	$ 1,444.57	$ 1,444.57	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kW		1,476	$ -	$ 0.2272	1,476	$ 335.41	$ 335.41	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kW		1,476	$ -	$ 0.0087	1,476	$ 12.83	$ 12.83	
Low Voltage Service Charge	per kW	$ 0.6632	1,476	$ 978.88	$ 1.0911	1,476	$ 1,610.40	$ 631.52	64.51%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6,267.16**			**$ 10,293.16**	**$ 4,026.00**	**64.24%**
RTSR - Network	per kW	$ 2.6973	1,582	$ 4,266.27	$ 2.7094	1,573	$ 4,261.43	-$ 4.84	-0.11%
RTSR - Line and Transformation Connection	per kW	$ 1.5577	1,582	$ 2,463.79	$ 1.6821	1,573	$ 2,645.65	$ 181.86	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 12,997.21**			**$ 17,200.23**	**$ 4,203.02**	**32.34%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	800,158	$ 3,520.70	$ 0.0036	795,678	$ 2,864.44	-$ 656.26	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	800,158	$ 1,040.21	$ 0.0013	795,678	$ 1,034.38	-$ 5.82	-0.56%
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	746,695	$ 5,226.87	$ 0.0070	746,695	$ 5,226.87	$ -	0.00%
Ontario Electricity Support Program (OESP)		$ 0.0011	800,158	$ 880.17	$ 0.0011	795,678	$ 875.25		0.00%
TOU - Off Peak				$ -			$ -	$ -	
TOU - Mid Peak				$ -			$ -	$ -	
TOU - On Peak				$ -			$ -	$ -	
Non-RPP Retailer Avg. Price				$ -			$ -	$ -	
Average IESO Wholesale Market Price		$ 0.0906	800,158	$ 72,494.35	$ 0.0906	795,678	$ 72,088.44	-$ 405.90	-0.56%
Total Bill on Average IESO Wholesale Market Price				**$ 96,159.75**			**$ 99,289.86**	**$ 3,130.11**	**3.26%**
HST		13%		$ 12,500.77	13%		$ 12,907.68	$ 406.91	3.26%
Total Bill (including HST)				$ 108,660.52			$ 112,197.55	$ 3,537.03	3.26%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 108,660.52**			**$ 112,197.55**	**$ 3,537.03**	**3.26%**

Unmetered Scattered Load RPP Customer – Monthly Consumption of 252 kWh:

Customer Class:	Unmetered Scattered Load	
RPP / Non-RPP:	RPP	
Consumption	252	kWh
Demand	-	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.09	1	$ 18.09	$ 28.33	1	$ 28.33	$ 10.24	56.59%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.8600	1	$ 0.86		1	$ -	-$ 0.86	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0146	252	$ 3.68	$ 0.0156	252	$ 3.93	$ 0.25	6.91%
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0007	252	$ 0.18		252	$ -	-$ 0.18	-100.00%
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
Sub-Total A (excluding pass through)				$ 22.81			$ 32.26	**$ 9.45**	**41.46%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		252	$ -	$ 0.0002	252	$ 0.05	$ 0.05	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		252	$ -	$ -	252	$ -	$ -	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kWh		252	$ -	$ 0.0005	252	$ 0.12	$ 0.12	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		252	$ -	-$ 0.0005	252	-$ 0.12	-$ 0.12	
Low Voltage Service Charge	per kWh	$ 0.0015	252	$ 0.38	$ 0.0025	252	$ 0.62	$ 0.24	63.44%
Line Losses on Cost of Power	per kWh	$ 0.1021	18	$ 1.84	$ 0.1021	17	$ 1.69	-$ 0.15	-8.38%
			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.03**			**$ 34.62**	**$ 9.59**	**38.33%**
RTSR - Network	per kWh	$ 0.0062	270	$ 1.67	$ 0.0062	269	$ 1.67	-$ 0.00	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0035	270	$ 0.95	$ 0.0038	269	$ 1.01	$ 0.07	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 27.65**			**$ 37.31**	**$ 9.66**	**34.94%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	270	$ 1.19	$ 0.0036	269	$ 0.97	-$ 0.22	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	270	$ 0.35	$ 0.0013	269	$ 0.35	-$ 0.00	-0.56%
Standard Supply Service Charge	per kWh	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	252	$ 1.76	$ 0.0070	252	$ 1.76	$ -	0.00%
Ontario Electricity Support Program (OESP)		$ 0.0011	270	$ 0.30	$ 0.0011	269	$ 0.30		0.00%
TOU - Off Peak		$ 0.0800	161	$ 12.90	$ 0.0800	161	$ 12.90	$ -	0.00%
TOU - Mid Peak		$ 0.1220	45	$ 5.53	$ 0.1220	45	$ 5.53	$ -	0.00%
TOU - On Peak		$ 0.1610	45	$ 7.30	$ 0.1610	45	$ 7.30	$ -	0.00%
Non-RPP Retailer Avg. Price				$ -			$ -	$ -	
Average IESO Wholesale Market Price				$ -			$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 57.24**			**$ 66.67**	**$ 9.44**	**16.48%**
HST		13%		$ 7.44	13%		$ 8.67	$ 1.23	16.48%
Total Bill (including HST)				$ 64.68			$ 75.34	$ 10.66	16.48%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 64.68**			**$ 75.34**	**$ 10.66**	**16.48%**

Sentinel Lighting RPP Customer – Monthly Demand of 5 kW:

Customer Class:	Sentinel Lighting
RPP / Non-RPP:	RPP
Consumption	1,927 kWh
Demand	5 kW
Current Loss Factor	1.0716
Proposed/Approved Loss Factor	1.0656
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 5.24	1	$ 5.24	$ 7.38	1	$ 7.38	$ 2.14	40.91%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.2500	1	$ 0.25		1	$ -	-$ 0.25	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 19.3776	5	$ 96.89	$ 27.3041	5	$ 136.52	$ 39.63	40.91%
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kW	$ 0.9234	5	$ 4.62		5	$ -	-$ 4.62	-100.00%
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
Sub-Total A (excluding pass through)				$ 107.00			$ 143.90	**$ 36.91**	**34.50%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.0686	5	$ 0.34	$ 0.34	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.7449	5	$ 3.72	$ 3.72	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.1729	5	$ 0.86	$ 0.86	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kW		5	$ -	-$ 1.0082	5	-$ 5.04	-$ 5.04	
Low Voltage Service Charge	per kW	$ 0.4775	5	$ 2.39	$ 0.7856	5	$ 3.93	$ 1.54	64.52%
Line Losses on Cost of Power		$ 0.1021	138	$ 14.09	$ 0.1021	126	$ 12.91	-$ 1.18	-8.38%
			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 123.48**			**$ 160.63**	**$ 37.16**	**30.09%**
RTSR - Network	per kW	$ 1.9248	5	$ 9.62	$ 1.9334	5	$ 9.67	$ 0.04	0.45%
RTSR - Line and Transformation Connection	per kW	$ 1.1215	5	$ 5.61	$ 1.2111	5	$ 6.06	$ 0.45	7.99%
Sub-Total C - Delivery (including Sub-Total B)				**$ 138.71**			**$ 176.36**	**$ 37.65**	**27.14%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2,065	$ 9.09	$ 0.0036	2,053	$ 7.39	-$ 1.69	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,065	$ 2.68	$ 0.0013	2,053	$ 2.67	-$ 0.02	-0.56%
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	1,927	$ 13.49	$ 0.0070	1,927	$ 13.49	$ -	0.00%
Ontario Electricity Support Program (OESP)		$ 0.0011	2,065	$ 2.27	$ 0.0011	2,053	$ 2.26		0.00%
TOU - Off Peak		$ 0.0800	1,233	$ 98.66	$ 0.0800	1,233	$ 98.66	$ -	0.00%
TOU - Mid Peak		$ 0.1220	347	$ 42.32	$ 0.1220	347	$ 42.32	$ -	0.00%
TOU - On Peak		$ 0.1610	347	$ 55.84	$ 0.1610	347	$ 55.84	$ -	0.00%
Non-RPP Retailer Avg. Price				$ -			$ -	$ -	
Average IESO Wholesale Market Price				$ -			$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 363.31**			**$ 399.24**	**$ 35.93**	**9.89%**
HST		13%		$ 47.23	13%		$ 51.90	$ 4.67	9.89%
Total Bill (including HST)				$ 410.54			$ 451.14	$ 40.60	9.89%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 410.54**			**$ 451.14**	**$ 40.60**	**9.89%**

Sentinel Lighting Non-RPP Customer – Monthly Demand of 5 kW:

Customer Class:	Sentinel Lighting Retailer
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	1,927 kWh
Demand	5 kW
Current Loss Factor	1.0716
Proposed/Approved Loss Factor	1.0656
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 5.24	1	$ 5.24	$ 7.38	1	$ 7.38	$ 2.14	40.91%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.2500	1	$ 0.25		1	$ -	-$ 0.25	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 19.3776	5	$ 96.89	$ 27.3041	5	$ 136.52	$ 39.63	40.91%
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kW	$ 0.9234	5	$ 4.62		5	$ -	-$ 4.62	-100.00%
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
Sub-Total A (excluding pass through)				$ 107.00			$ 143.90	**$ 36.91**	**34.50%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.0686	5	$ 0.34	$ 0.34	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.7449	5	$ 3.72	$ 3.72	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.1729	5	$ 0.86	$ 0.86	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kW		5	$ -	-$ 1.0082	5	-$ 5.04	-$ 5.04	
Low Voltage Service Charge	per kW	$ 0.4775	5	$ 2.39	$ 0.7856	5	$ 3.93	$ 1.54	64.52%
Line Losses on Cost of Power		$ 0.0860	138	$ 11.87	$ 0.0860	126	$ 10.87	-$ 0.99	-8.38%
			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 121.25**			**$ 158.59**	**$ 37.35**	**30.80%**
RTSR - Network	per kW	$ 1.9248	5	$ 9.62	$ 1.9334	5	$ 9.67	$ 0.04	0.45%
RTSR - Line and Transformation Connection	per kW	$ 1.1215	5	$ 5.61	$ 1.2111	5	$ 6.06	$ 0.45	7.99%
Sub-Total C - Delivery (including Sub-Total B)				**$ 136.48**			**$ 174.32**	**$ 37.84**	**27.72%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2,065	$ 9.09	$ 0.0036	2,053	$ 7.39	-$ 1.69	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,065	$ 2.68	$ 0.0013	2,053	$ 2.67	-$ 0.02	-0.56%
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	1,927	$ 13.49	$ 0.0070	1,927	$ 13.49	$ -	0.00%
Ontario Electricity Support Program (OESP)		$ 0.0011	2,065	$ 2.27	$ 0.0011	2,053	$ 2.26		0.00%
Non-RPP Retailer Avg. Price		$ 0.0860	1,927	$ 165.72	$ 0.0860	1,927	$ 165.72	$ -	0.00%
Average IESO Wholesale Market Price		$ 0.0906	1,927	$ 174.59	$ 0.0906	1,927	$ 174.59	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 428.64**			**$ 464.76**	**$ 36.12**	**8.43%**
HST		13%		$ 55.72	13%		$ 60.42	$ 4.70	8.43%
Total Bill (including HST)				$ 484.37			$ 525.18	$ 40.81	8.43%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 484.37**			**$ 525.18**	**$ 40.81**	**8.43%**

Street Lighting Non-RPP Customer – Monthly Demand of 165 kW:

Customer Class:	Street Lighting	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	64,297	kWh
Demand	165	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 7.12	1	$ 7.12	$ 1.60	1	$ 1.60	-$ 5.52	-77.50%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.3400	1	$ 0.34		1	$ -	-$ 0.34	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 7.9283	165	$ 1,308.17	$ 1.7664	165	$ 291.45	-$ 1,016.72	-77.72%
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kW	$ 0.3778	165	$ 62.34		165	$ -	-$ 62.34	-100.00%
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
Sub-Total A (excluding pass through)				$ 1,377.97			$ 293.05	**-$ 1,084.91**	**-78.73%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kW		165	$ -	$ 0.0699	165	$ 11.53	$ 11.53	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kW		165	$ -	$ 0.7615	165	$ 125.65	$ 125.65	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kW		165	$ -	$ 0.1768	165	$ 29.17	$ 29.17	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kW		165	$ -	-$ 0.1947	165	-$ 32.12	-$ 32.12	
Low Voltage Service Charge		$ 0.4677	165	$ 77.17	$ 0.7695	165	$ 126.97	$ 49.80	64.53%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,455.14**			**$ 554.25**	**-$ 900.89**	**-61.91%**
RTSR - Network	per kW	$ 1.9151	177	$ 338.62	$ 1.9237	176	$ 338.23	-$ 0.38	-0.11%
RTSR - Line and Transformation Connection	per kW	$ 1.0986	177	$ 194.25	$ 1.1863	176	$ 208.59	$ 14.34	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,988.00**			**$ 1,101.07**	**-$ 886.93**	**-44.61%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	68,901	$ 303.16	$ 0.0036	68,515	$ 246.65	-$ 56.51	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	68,901	$ 89.57	$ 0.0013	68,515	$ 89.07	-$ 0.50	-0.56%
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	64,297	$ 450.08	$ 0.0070	64,297	$ 450.08	$ -	0.00%
Ontario Electricity Support Program (OESP)		$ 0.0011	68,901	$ 75.79	$ 0.0011	68,515	$ 75.37		0.00%
TOU - Off Peak				$ -			$ -	$ -	
TOU - Mid Peak				$ -			$ -	$ -	
TOU - On Peak				$ -			$ -	$ -	
Non-RPP Retailer Avg. Price				$ -			$ -	$ -	
Average IESO Wholesale Market Price		$ 0.0906	68,901	$ 6,242.40	$ 0.0906	68,515	$ 6,207.45	-$ 34.95	-0.56%
Total Bill on Average IESO Wholesale Market Price				**$ 9,149.26**			**$ 8,169.93**	**-$ 979.32**	**-10.70%**
HST		13%		$ 1,189.40	13%		$ 1,062.09	-$ 127.31	-10.70%
Total Bill (including HST)				$ 10,338.66			$ 9,232.03	-$ 1,106.63	-10.70%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 10,338.66**			**$ 9,232.03**	**-$ 1,106.63**	**-10.70%**

C. Capital Expenditure Summary – Appendix 2-AA and Appendix 2-AB

Capital Projects (historic, 2015 Bridge Year and 2016 Test Year):

Appendix 2-AA
Capital Projects Table

Projects	2011	2012	2013	2014	2015 Bridge Year	2016 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
General Plant						
Non-system physical plant - Building structure	19,274	56,564	7,384	4,250	77,000	30,000
Non-system physical plant - Equipment & Tools	6,719	1,842	309,831	3,340	35,000	
Non-system physical plant - Land Rights / Acquisition	1,006	2,843	6,835	3,993		
Non-system physical plant - Software / Hardware	42,532	77,026	35,528	27,034	108,000	40,650
System capital investment support - Asset Management Study	27,911					
Sub-Total	97,442	138,275	359,578	38,617	220,000	70,650
System Access						
Customer Service Request	100,386	89,303	55,279	221,881	84,000	60,000
Customer Service Request - Contributed Capital	-113,405	-4,691		-113,297	-130,000	
Compliance - Financial Software	230,549					
Metering	41,576	15,587	2,450	17,203		
Other 3rd party infrastructure development requirements	14,374	6,972			88,500	
Sub-Total	273,480	107,171	57,730	125,787	42,500	60,000
System Renewal						
Failure risk - Asset replacement	192,014	307,636	283,467	413,894	285,500	90,000
Special Project - MS2 Substation replacement (Incremental Capital Module as part of IRM application EB-2014-0178)				1,433,955		
Sub-Total	192,014	307,636	283,467	1,847,849	285,500	90,000
System Service						
Operational Effectiveness	34,362	13,375	56,912	61,613	212,000	
Special Project - 2nd line feeder to Mount Forest (construction by Hydro One. Will be a contributed capital payment from WNP to HO)						913,261
New Primary Meter Equipment (PME) at 2nd line feeder demarcation point of WNP service area						80,000
Construction of new pole line to connect new 2nd line feeder 44kV to WNP's MS1 substation						380,000
Sub-Total	34,362	13,375	56,912	61,613	212,000	1,373,261
Miscellaneous						
Total	**597,299**	**566,457**	**757,686**	**2,073,866**	**760,000**	**1,593,911**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*						
Total	**597,299**	**566,457**	**757,686**	**2,073,866**	**760,000**	**1,593,911**

Chapter 5 Consolidated DSP with forecast for 2016 to 2020 Capital Projects:

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

First year of Forecast Period: 2016

CATEGORY	Historical Period (previous plan[1] & actual)														
	2011			2012			2013			2014			2015		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	156	43	-72.5%	102	107	5.1%	55	58	5.2%	229	239	4.5%	173	35	-79.9%
System Renewal	231	192	-17.0%	261	308	18.0%	273	283	3.8%	1,756	1,848	5.2%	156	206	32.6%
System Service	39	34	-12.1%	9	13	46.1%	56	55	-1.3%	66	62	-5.9%	212	17	-92.2%
General Plant	243	328	34.8%	152	138	-9.3%	377	362	-4.1%	25	39	57.6%	220	77	-65.1%
TOTAL EXPENDITURE	670	597	-10.9%	524	566	8.0%	760	758	-0.4%	2,075	2,187	5.4%	760	334	-56.0%
System O&M		$ 530	--	$ 501	$ 589	17.4%	$ 570	$ 588	3.2%	$ 583	$ 568	-2.6%	$ 613	$ 394	-35.7%

CATEGORY	Forecast Period (planned)				
	2016	2017	2018	2019	2020
	$ '000				
System Access	60	240	240	240	60
System Renewal	90	390	1,932	290	450
System Service	1,373	-	-	-	-
General Plant	71	139	24	422	453
TOTAL EXPENDITURE	1,594	769	2,196	952	963
System O&M	$ 655	$ 671	$ 688	$ 705	$ 722

D. Revenue Requirement Workform

Updated Revenue Requirement Form - Applicant:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Version 6.00

Utility Name	Wellington North Power Inc.
Service Territory	
Assigned EB Number	EB-2015-0110
Name and Title	Richard Bucknall, CAO
Phone Number	1-519-323-1710
Email Address	rbucknall@wellingtonnorthpower.com

Updated Revenue Requirement Form – Data Input:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Data Input [1]

		Initial Application	(2)	Adjustments	Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$16,008,237		($191,943)	$ 15,816,294			$15,816,294	
	Accumulated Depreciation (average)	($7,604,099)	(5)	$53,645	($7,550,454)			($7,550,454)	
	Allowance for Working Capital:								
	Controllable Expenses	$1,811,368		($74,459)	$ 1,736,909			$1,736,909	
	Cost of Power	$13,117,919		$963,595	$ 14,081,514			$14,081,514	
	Working Capital Rate (%)	7.50%	(9)		7.50%	(9)		7.50%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$2,333,709		$43,193	$2,376,902				
	Distribution Revenue at Proposed Rates	$2,592,599		($53,526)	$2,539,073				
	Other Revenue:								
	Specific Service Charges	$60,474		($2,177)	$58,297				
	Late Payment Charges	$27,012		$1,988	$29,000				
	Other Distribution Revenue	$62,102		($794)	$61,308				
	Other Income and Deductions	$1,000		($19,500)	($18,500)				
	Total Revenue Offsets	$150,588	(7)	($20,483)	$130,105				
	Operating Expenses:								
	OM+A Expenses	$1,793,368		($73,368)	$ 1,720,000			$1,720,000	
	Depreciation/Amortization	$361,570		$4,209	$ 365,779			$365,779	
	Property taxes	$14,000		$ -	$ 14,000			$14,000	
	Other expenses	$4,000		($1,091)	2909			$2,909	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($386,767)	(3)		($367,805)			($367,805)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$ -			$ -				
	Income taxes (grossed up)	$ -			$ -				
	Federal tax (%)	0.00%			0.00%				
	Provincial tax (%)	0.00%			0.00%				
	Income Tax Credits	$ -			$ -				
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%				
	Prefered Shares Capitalization Ratio (%)	0.0%							
		100.0%			100.0%				
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.01%			4.02%			4.02%	
	Short-term debt Cost Rate (%)	1.65%			1.65%				
	Common Equity Cost Rate (%)	9.19%			9.19%				
	Prefered Shares Cost Rate (%)	0.00%			0.00%				

Updated Revenue Requirement Form – Rate Base:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$16,008,237	($191,943)	$15,816,294	$ -	$15,816,294
2	Accumulated Depreciation (average)	(3)	($7,604,099)	$53,645	($7,550,454)	$ -	($7,550,454)
3	Net Fixed Assets (average)	(3)	$8,404,138	($138,299)	$8,265,840	$ -	$8,265,840
4	Allowance for Working Capital	(1)	$1,119,697	$66,685	$1,186,382	$ -	$1,186,382
5	**Total Rate Base**		$9,523,835	($71,613)	$9,452,221	$ -	$9,452,221

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$1,811,368	($74,459)	$1,736,909	$ -	$1,736,909
7	Cost of Power		$13,117,919	$963,595	$14,081,514	$ -	$14,081,514
8	Working Capital Base		$14,929,287	$889,136	$15,818,423	$ -	$15,818,423
9	Working Capital Rate %	(2)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$1,119,697	$66,685	$1,186,382	$ -	$1,186,382

Updated Revenue Requirement Form – Utility Income:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$2,592,599	($53,526)	$2,539,073	$ -	$2,539,073
2	Other Revenue	(1)	$150,588	($20,483)	$130,105	$ -	$130,105
3	Total Operating Revenues		$2,743,188	($74,009)	$2,669,178	$ -	$2,669,178
	Operating Expenses:						
4	OM+A Expenses		$1,793,368	($73,368)	$1,720,000	$ -	$1,720,000
5	Depreciation/Amortization		$361,570	$4,209	$365,779	$ -	$365,779
6	Property taxes		$14,000	$ -	$14,000	$ -	$14,000
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$4,000	($1,091)	$2,909	$ -	$2,909
9	Subtotal (lines 4 to 8)		$2,172,938	($70,250)	$2,102,688	$ -	$2,102,688
10	Deemed Interest Expense		$220,153	($1,126)	$219,027	$ -	$219,027
11	Total Expenses (lines 9 to 10)		$2,393,091	($71,376)	$2,321,715	$ -	$2,321,715
12	**Utility income before income taxes**		$350,096	($2,633)	$347,464	$ -	$347,464
13	Income taxes (grossed-up)		$ -	$ -	$ -	$ -	$ -
14	**Utility net income**		$350,096	($2,633)	$347,464	$ -	$347,464

Notes

Other Revenues / Revenue Offsets

Notes	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$60,474	($2,177)	$58,297		$58,297
	Late Payment Charges	$27,012	$1,988	$29,000		$29,000
	Other Distribution Revenue	$62,102	($794)	$61,308		$61,308
	Other Income and Deductions	$1,000	($19,500)	($18,500)		($18,500)
	Total Revenue Offsets	$150,588	($20,483)	$130,105	$ -	$130,105

Updated Revenue Requirement Form – Taxes / PILs:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$350,096	$347,464	$347,464
2	Adjustments required to arrive at taxable utility income	($386,767)	($367,805)	($367,805)
3	Taxable income	($36,670)	($20,341)	($20,341)
	Calculation of Utility income Taxes			
4	Income taxes	$ -	$ -	$ -
6	Total taxes	$ -	$ -	$ -
7	Gross-up of Income Taxes	$ -	$ -	$ -
8	Grossed-up Income Taxes	$ -	$ -	$ -
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$ -	$ -	$ -
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	0.00%	0.00%	0.00%
12	Provincial tax (%)	0.00%	0.00%	0.00%
13	Total tax rate (%)	0.00%	0.00%	0.00%

Updated Revenue Requirement Form – Cost of Capital:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$5,333,347	4.01%	$213,867
2	Short-term Debt	4.00%	$380,953	1.65%	$6,286
3	**Total Debt**	60.00%	$5,714,301	3.85%	$220,153
	Equity				
4	Common Equity	40.00%	$3,809,534	9.19%	$350,096
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$3,809,534	9.19%	$350,096
7	**Total**	100.00%	$9,523,835	5.99%	$570,249
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$5,293,244	4.02%	$212,788
2	Short-term Debt	4.00%	$378,089	1.65%	$6,238
3	**Total Debt**	60.00%	$5,671,333	3.86%	$219,027
	Equity				
4	Common Equity	40.00%	$3,780,888	9.19%	$347,464
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$3,780,888	9.19%	$347,464
7	**Total**	100.00%	$9,452,221	5.99%	$566,491
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$5,293,244	4.02%	$212,788
9	Short-term Debt	4.00%	$378,089	1.65%	$6,238
10	**Total Debt**	60.00%	$5,671,333	3.86%	$219,027
	Equity				
11	Common Equity	40.00%	$3,780,888	9.19%	$347,464
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$3,780,888	9.19%	$347,464
14	**Total**	100.00%	$9,452,221	5.99%	$566,491

Updated Revenue Requirement Form – Revenue / Sufficiency:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application		Settlement Agreement		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$258,890		$162,171		$162,171
2	Distribution Revenue	$2,333,709	$2,333,709	$2,376,902	$2,376,902	$2,376,902	$2,376,902
3	Other Operating Revenue Offsets - net	$150,588	$150,588	$130,105	$130,105	$130,105	$130,105
4	Total Revenue	$2,484,297	$2,743,188	$2,507,007	$2,669,178	$2,507,007	$2,669,178
5	Operating Expenses	$2,172,938	$2,172,938	$2,102,688	$2,102,688	$2,102,688	$2,102,688
6	Deemed Interest Expense	$220,153	$220,153	$219,027	$219,027	$219,027	$219,027
8	Total Cost and Expenses	$2,393,091	$2,393,091	$2,321,715	$2,321,715	$2,321,715	$2,321,715
9	Utility Income Before Income Taxes	$91,206	$350,096	$185,293	$347,464	$185,293	$347,464
10	Tax Adjustments to Accounting Income per 2013 PILs model	($386,767)	($386,767)	($367,805)	($367,805)	($367,805)	($367,805)
11	Taxable Income	($295,561)	($36,670)	($182,512)	($20,341)	($182,512)	($20,341)
12	Income Tax Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	Income Tax on Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -
14	Income Tax Credits	$ -	$ -	$ -	$ -	$ -	$ -
15	Utility Net Income	$91,206	$350,096	$185,293	$347,464	$185,293	$347,464
16	Utility Rate Base	$9,523,835	$9,523,835	$9,452,221	$9,452,221	$9,452,221	$9,452,221
17	Deemed Equity Portion of Rate Base	$3,809,534	$3,809,534	$3,780,888	$3,780,888	$3,780,888	$3,780,888
18	Income/(Equity Portion of Rate Base)	2.39%	9.19%	4.90%	9.19%	4.90%	9.19%
19	Target Return - Equity on Rate Base	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%
20	Deficiency/Sufficiency in Return on Equity	-6.80%	0.00%	-4.29%	0.00%	-4.29%	0.00%
21	Indicated Rate of Return	3.27%	5.99%	4.28%	5.99%	4.28%	5.99%
22	Requested Rate of Return on Rate Base	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%
23	Deficiency/Sufficiency in Rate of Return	-2.72%	0.00%	-1.72%	0.00%	-1.72%	0.00%
24	Target Return on Equity	$350,096	$350,096	$347,464	$347,464	$347,464	$347,464
25	Revenue Deficiency/(Sufficiency)	$258,890	$0	$162,171	($0)	$162,171	($0)
26	Gross Revenue Deficiency/(Sufficiency)	$258,890 **(1)**		$162,171 **(1)**		$162,171 **(1)**	

Updated Revenue Requirement Form – Test Year Revenue Requirement:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$1,793,368		$1,720,000		$1,720,000	
2	Amortization/Depreciation	$361,570		$365,779		$365,779	
3	Property Taxes	$14,000		$14,000		$14,000	
5	Income Taxes (Grossed up)	$ -		$ -		$ -	
6	Other Expenses	$4,000		$2,909		$2,909	
7	Return						
	Deemed Interest Expense	$220,153		$219,027		$219,027	
	Return on Deemed Equity	$350,096		$347,464		$347,464	
8	**Service Revenue Requirement (before Revenues)**	$2,743,187		$2,669,178		$2,669,178	
9	Revenue Offsets	$150,588		$130,105		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$2,592,599		$2,539,073		$2,669,178	
11	Distribution revenue	$2,592,599		$2,539,073		$2,539,073	
12	Other revenue	$150,588		$130,105		$130,105	
13	**Total revenue**	$2,743,188		$2,669,178		$2,669,178	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	($0)	(1)	($0)	(1)

Updated Revenue Requirement Form – Tracking Sheet:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Tracking Form

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

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

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 570,249	5.99%	$ 9,523,835	$ 14,929,287	$ 1,119,697	$ 361,570	$ -	$ 1,793,368	$ 2,743,187	$ 150,588	$ 2,592,599	$ 258,890
1	2-Staff-10	Update Fixed Assets with 2015 Actuals.	$ 572,104	5.99%	$ 9,554,814	$ 14,929,287	$ 1,119,697	$ 359,212	$ -	$ 1,793,368	$ 2,742,684	$ 147,988	$ 2,594,696	$ 260,987
	2-Energy Probe-4	Change	$ 1,855	0.00%	$ 30,979	-$ 0	$ 0	-$ 2,358	$ -	$ -	-$ 503	-$ 2,600	$ 2,097	$ 2,097
2	2-Staff-7	44kV Feeder price based on Economic Evaluation Model	$ 566,894	5.99%	$ 9,467,804	$ 14,929,287	$ 1,119,697	$ 356,443	$ -	$ 1,793,368	$ 2,734,705	$ 147,988	$ 2,586,717	$ 253,009
		Change	-$ 5,210	0.00%	-$ 87,010	$ -	$ -	-$ 2,769	$ -	$ -	-$ 7,979	$ -	-$ 7,979	-$ 7,978
3	2-Staff-9 (d)	10 year useful life on Smart Meters.	$ 565,063	5.99%	$ 9,437,212	$ 14,929,287	$ 1,119,697	$ 417,626	$ 4,642	$ 1,793,368	$ 2,794,057	$ 147,988	$ 2,646,069	$ 312,360
	4-Energy Probe-25 (d)	Change	-$ 1,831	0.00%	-$ 30,592	$ -	$ -	$ 61,183	$ 4,642	$ -	$ 59,352	$ -	$ 59,352	$ 59,351
4	2-Staff-12, 2-EP-7, 2-EP-8,	Update Cost of Power	$ 567,946	5.99%	$ 9,485,374	$ 15,571,440	$ 1,167,858	$ 417,626	$ 4,981	$ 1,793,368	$ 2,801,403	$ 147,988	$ 2,653,415	$ 319,855
	8-Staff-51, 8-VECC-43, 8-	Change	$ 2,883	0.00%	$ 48,162	$ 642,153	$ 48,161	$ -	$ 339	$ -	$ 7,346	$ -	$ 7,346	$ 7,495
5	3-Energy Probe -13 (a)	Load Forecast Update	$ 569,051	5.99%	$ 9,503,828	$ 15,817,499	$ 1,186,312	$ 417,626	$ 5,102	$ 1,793,368	$ 2,802,628	$ 147,988	$ 2,654,640	$ 321,084
		Change	$ 1,105	0.00%	$ 18,454	$ 246,059	$ 18,454	$ -	$ 121	$ -	$ 1,225	$ -	$ 1,225	$ 1,229
6	3-VECC-20	Update Other Income	$ 569,051	5.99%	$ 9,503,828	$ 15,817,499	$ 1,186,312	$ 417,626	$ 5,102	$ 1,793,368	$ 2,802,628	$ 128,808	$ 2,673,821	$ 340,264
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 19,180	$ 19,181	$ 19,180
7	4-VECC-30, 4-Staff-43, 4-	Update OM&A	$ 569,062	5.99%	$ 9,504,005	$ 15,819,859	$ 1,186,489	$ 417,626	$ 5,103	$ 1,795,728	$ 2,805,000	$ 128,808	$ 2,676,192	$ 342,636
	EP-19(b), 4-EP-19(c), 4-EP-	Change	$ 11	0.00%	$ 177	$ 2,360	$ 177	$ -	$ 1	$ 2,360	$ 2,372	$ -	$ 2,371	$ 2,372
8	2-Staff-7(c), 5-VECC-35(a-	Update Loans and Cost of Capital	$ 571,191	6.01%	$ 9,504,005	$ 15,819,859	$ 1,186,489	$ 417,626	$ 5,103	$ 1,795,728	$ 2,807,129	$ 128,808	$ 2,678,321	$ 344,765
	b), 5-VECC-37	Change	$ 2,129	0.02%	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,129	$ -	$ 2,129	$ 2,129
9	Change on Revenue at	A result from Load Forecast changes as per line 5 above	$ 570,725	6.01%	$ 9,496,255	$ 15,819,859	$ 1,186,489	$ 417,626	$ 5,051	$ 1,795,728	$ 2,807,130	$ 128,808	$ 2,678,323	$ 313,936
	current rates	Change	-$ 466	0.00%	-$ 7,750	$ -	$ -	$ -	-$ 52	$ -	$ 1	$ -	$ 2	-$ 30,829
10	Settlement Proposal	Update OM&A to $1,720,000	$ 570,379	6.01%	$ 9,490,494	$ 15,743,040	$ 1,180,728	$ 417,626	$ 5,011	$ 1,720,000	$ 2,729,925	$ 128,808	$ 2,601,117	$ 236,730
		Change	-$ 346	0.00%	-$ 5,761	-$ 76,819	-$ 5,761	$ -	-$ 40	-$ 75,728	-$ 77,205	$ -	-$ 77,206	-$ 77,206
11	Settlement Proposal	Smart Meter Depreciation - change back to 15 years	$ 570,379	6.01%	$ 9,490,494	$ 15,743,040	$ 1,180,728	$ 356,443	$ -	$ 1,720,000	$ 2,665,570	$ 128,808	$ 2,536,762	$ 172,375
		Change	$ -	0.00%	$ -	$ -	$ -	-$ 61,183	-$ 5,011	$ -	-$ 64,355	$ -	-$ 64,355	-$ 64,355
12	Settlement Proposal	Add $40,000 to the Capital Budget	$ 573,359	6.01%	$ 9,540,085	$ 15,743,040	$ 1,180,728	$ 358,443	$ -	$ 1,720,000	$ 2,668,711	$ 128,808	$ 2,539,904	$ 175,517
		Change	$ 2,980	0.00%	$ 49,591	$ -	$ -	$ 2,000	$ -	$ -	$ 3,141	$ -	$ 3,142	$ 3,142
13	Settlement Proposal	Revised HONI Estimate & HONI life-span	$ 567,738	6.01%	$ 9,446,568	$ 15,743,040	$ 1,180,728	$ 365,779	$ -	$ 1,720,000	$ 2,670,427	$ 128,808	$ 2,541,619	$ 177,232
		Change	-$ 5,621	0.00%	-$ 93,517	$ -	$ -	$ 7,336	$ -	$ -	$ 1,716	$ -	$ 1,715	$ 1,715
14	Settlement Proposal	Revised Load Forecast and Cost of Power	$ 568,191	6.01%	$ 9,454,096	$ 15,843,423	$ 1,188,257	$ 365,779	$ -	$ 1,720,000	$ 2,670,879	$ 128,808	$ 2,542,072	$ 165,169
		Change	$ 453	0.00%	$ 7,528	$ 100,383	$ 7,529	$ -	$ -	$ -	$ 452	$ -	$ 453	-$ 12,063
15	Settlement Proposal	MicroFIT Monthly Service Charge of $15.69	$ 568,191	6.01%	$ 9,454,096	$ 15,843,423	$ 1,188,257	$ 365,779	$ -	$ 1,720,000	$ 2,670,879	$ 130,105	$ 2,540,774	$ 163,872
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,297	-$ 1,298	-$ 1,297
16	Settlement Proposal	Deduct Fully allocated Depr'n from working capital allowance	$ 568,078	6.01%	$ 9,452,221	$ 15,818,423	$ 1,186,382	$ 365,779	$ -	$ 1,720,000	$ 2,670,766	$ 130,105	$ 2,540,662	$ 163,759
		Change	-$ 113	0.00%	-$ 1,875	-$ 25,000	-$ 1,875	$ -	$ -	$ -	-$ 113	$ -	-$ 112	-$ 113
17	Settlement Proposal	Adjust Cost of Capital based on future loan rate	$ 566,490	5.99%	$ 9,452,221	$ 15,818,423	$ 1,186,382	$ 365,779	$ -	$ 1,720,000	$ 2,669,178	$ 130,105	$ 2,539,074	$ 162,171
		Change	-$ 1,588	-0.02%	$ -	$ -	$ -	$ -	$ -	$ -	-$ 1,588	$ -	-$ 1,588	-$ 1,588

E. PILS Model

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Rate Base		S	**$**	**9,452,221**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$	378,089	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	5,293,244	*X = S * U*
Deemed Equity %	40.00%	V	$	3,780,888	*Y = S * V*
Short Term Interest Rate	1.65%	Z	$	6,238	*AC = W * Z*
Long Term Interest	4.02%	AA	$	212,788	*AD = X * AA*
Return on Equity (Regulatory Income)	9.19%	AB	**$**	**347,464**	*AE = Y * AB* T1
Return on Rate Base			**$**	**566,491**	*AF = AC + AD + AE*

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

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

PILs Tax Provision - Test Year

					Wires Only		
Regulatory Taxable Income				T1	-$ 20,341	A	
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	4.50%	B				
	Federal tax rate (Maximum 15%)	10.50%	C				
	Combined tax rate (Maximum 26.5%)				15.00%	D = B + C	
Total Income Taxes					-$ 3,051	E = A * D	
Investment Tax Credits						F	
Miscellaneous Tax Credits						G	
Total Tax Credits					$ -	H = F + G	
Corporate PILs/Income Tax Provision for Test Year					$ -	I = H + E	S. Summary
Corporate PILs/Income Tax Provision Gross Up [1]		85.00%	J		$ -	K = J * I	
Income Tax (grossed-up)					$ -	L = K + I	S. Summary

Note:

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

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	347,464
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		347,513
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		18,265
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		12,500
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		1,750
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	0
Reserves from financial statements- balance at end of year	126	T13	0
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions: (please explain in detail the nature of the item)			
Interest Expensed on Capital Leases	290		
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		
	294		
	295		
	296		
	297		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Variance Adjustment			37,000
Increase in Employee Future Benefits			568
Total Additions			**417,597**

Deductions:			
Gain on disposal of assets per financial statements	401		0
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	T8	755,402
Terminal loss from Schedule 8	404		
Cumulative eligible capital deduction from Schedule 10 CEC	405	T10	0
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413	T13	0
Reserves from financial statements - balance at beginning of year	414	T13	0
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
	394		
	395		
	396		
	397		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Decrease in Employee Future Benefits			
Benefits expensed for tax, capitalized for accounting			30,000
Total Deductions		calculated	785,402
NET INCOME FOR TAX PURPOSES		calculated	-20,341
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of preceding taxation years from Schedule 7-1	331	T4	0
Net-capital losses of preceding taxation years (Please show calculation)	332		
Limited partnership losses of preceding taxation years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	-20,341

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Working Paper Reference	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year	B4	0		0
				0
Other Adjustments Add (+) Deduct (-)	T1	20,341		20,341
Balance available for use in Test Year	calculated	20,341	0	20,341
Amount to be used in Test Year	T1	0		0
Balance available for use post Test Year	calculated	20,341	0	20,341

Net Capital Loss Carry Forward Deduction		Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year	B4	0		0
				0
Other Adjustments Add (+) Deduct (-)				0
Balance available for use in Test Year	calculated	0	0	0
Amount to be used in Test Year				0
Balance available for use post Test Year	calculated	0	0	0

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Income Tax/PILs Workform for 2016 Filers

Schedule 8 CCA - Test Year

Class	Class Description	Working Paper Reference	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA		UCC End of Test Year
1	Distribution System - post 1987	B8	$ 252,856	0		$ 252,856	$ -	$ 252,856	4%	$ 10,114		$ 242,742
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	B8	$ 2,849,494	30,000		$ 2,879,494	$ 15,000	$ 2,864,494	6%	$ 171,870		$ 2,707,624
2	Distribution System - pre 1988	B8	$ -			$ -	$ -	$ -	6%	$ -		$ -
8	General Office/Stores Equip	B8	$ -			$ -	$ -	$ -	20%	$ -		$ -
10	Computer Hardware/ Vehicles	B8	$ 247,220	39,350		$ 286,570	$ 19,675	$ 266,895	30%	$ 80,069		$ 206,502
10.1	Certain Automobiles	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	B8	$ -			$ -	$ -	$ -	100%	$ -		$ -
13 1	Lease # 1	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 2	Lease #2	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4	B8	$ -			$ -	$ -	$ -		$ -		$ -
14	Franchise	B8	$ -			$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Tha	B8	$ -			$ -	$ -	$ -	8%	$ -		$ -
42	Fibre Optic Cable	B8	$ -			$ -	$ -	$ -	12%	$ -		$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
43.2	Certain Clean Energy Generation Equipment	B8	$ -			$ -	$ -	$ -	50%	$ -		$ -
45	Computers & Systems Software acq'd post Mar 22/04	B8	$ 23,843	1,300		$ 25,143	$ 650	$ 24,493	45%	$ 11,022		$ 14,121
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
47	Distribution System - post February 2005	B8	$ 5,224,299	1,493,261	-12,500	$ 6,705,060	$ 740,381	$ 5,964,680	8%	$ 477,174		$ 6,227,886
50	Data Network Infrastructure Equipment - post Mar 2007	B8	$ 9,369	0		$ 9,369	$ -	$ 9,369	55%	$ 5,153		$ 4,216
52	Computer Hardware and system software	B8	$ -			$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	B8	$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	5%	$ -		$ -
			$ -			$ -	$ -	$ -	10%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
	TOTAL		$ 8,607,082	$ 1,563,911	-$ 12,500	$ 10,158,493	$ 775,706	$ 9,382,787		$ 755,402	T1	$ 9,403,091

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital				B10	0
Additions					
Cost of Eligible Capital Property Acquired during Test Year		0			
Other Adjustments		0			
	Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002		0	x 1/2 =	0	
				0	0
Amount transferred on amalgamation or wind-up of subsidiary		0			0
	Subtotal				0
Deductions					
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year		0			
Other Adjustments		0			
	Subtotal	0	x 3/4 =		0
Cumulative Eligible Capital Balance					0
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")			0	x 7% =	0	T1
Cumulative Eligible Capital - Closing Balance					0

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Working Paper Reference	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	B13	0		0				0		0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	B13	0		0		0	0	0		0	
Reserve for goods and services not delivered ss. 20(1)(m)	B13	0		0				0		0	
Reserve for unpaid amounts ss. 20(1)(n)	B13	0		0				0		0	
Debt & Share Issue Expenses ss. 20(1)(e)	B13	0		0				0		0	
Other tax reserves	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		0	0	0	T1	0	0	0	T1	0	0
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	B13	0		0				0		0	
General reserve for bad debts	B13	0		0				0		0	
Accrued Employee Future Benefits:	B13	0		0				0		0	
- Medical and Life Insurance	B13	0		0				0		0	
-Short & Long-term Disability	B13	0		0				0		0	
-Accmulated Sick Leave	B13	0		0				0		0	
- Termination Cost	B13	0		0				0		0	
- Other Post-Employment Benefits	B13	0		0				0		0	
Provision for Environmental Costs	B13	0		0				0		0	
Restructuring Costs	B13	0		0				0		0	
Accrued Contingent Litigation Costs	B13	0		0				0		0	
Accrued Self-Insurance Costs	B13	0		0				0		0	
Other Contingent Liabilities	B13	0		0				0		0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	B13	0		0				0		0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	B13	0		0				0		0	
Other	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		0	0	0	T1	0	0	0	T1	0	0

F. Load Forecast

Load Forecast – Summary:

Wellington North Power Inc. Weather Normal Load Forecast for 2016 Rate Application														
EB-2015-0110														
	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Weather Normal	2016 Weather Normal		2015 Actual
Actual kWh Purchases	99,177,535	99,726,775	101,905,199	100,510,261	93,415,382	102,608,265	105,625,698	108,411,817	110,314,060	112,420,512				112,562,117
Settlement Conference											Intervenor Proposed Predicted kWh Purchases	115,125,000		
											WNP's IR (3-Energy Probe-13 excluding Trend Variable)	113,503,939		
											Difference	1,621,061		
											Agreement to use 1/2 between Intervenor Proposed and WNP Forecast	810,531		
Predicted kWh Purchases	100,203,868	99,566,097	101,456,606	99,715,122	96,051,561	101,470,115	104,257,827	105,015,880	111,948,346	114,430,079	111,874,945	114,314,469		111,874,945
% Difference	1.0%	-0.2%	-0.4%	-0.8%	2.8%	-1.1%	-1.3%	-3.1%	1.5%	1.8%				-0.6%
CDM Purchase Adjustment						0	0	0	0	0	(698,121)	(1,748,974)		
Predicted kWh Purchases after CDM											111,176,824	112,565,495		
Billed kWh	92,239,845	93,628,881	95,248,613	93,522,520	86,446,481	96,062,450	99,140,087	101,548,388	103,789,320	105,637,369	104,033,470	105,332,916		105,811,007
By Class														
Residential														
Customers	2,869	2,923	2,959	3,002	3,037	3,073	3,103	3,126	3,161	3,190	3,220	3,251		3,211
kWh	25,217,181	25,227,824	25,023,794	25,142,788	25,158,787	25,200,723	25,802,534	24,795,447	25,357,835	25,941,256	25,871,120	27,408,200		25,207,976
General Service < 50 kW														
Customers	462	455	455	464	468	479	478	478	474	473	474	476		477
kWh	12,036,675	11,886,853	11,930,026	11,678,034	11,573,828	11,323,787	11,781,553	11,710,253	12,012,886	11,877,868	11,819,833	12,494,682		12,150,298
General Service 50 to 999 kW														
Customers	40	38	39	41	43	40	38	38	39	38	38	38		36
kWh	30,016,678	29,919,925	24,233,832	25,169,769	20,973,876	20,890,084	21,438,642	21,823,125	17,140,222	15,634,133	14,482,546	14,065,279		20,135,704
kW	45,546	51,134	72,261	73,818	64,960	62,105	65,571	67,391	53,734	47,684	44,648	43,362		55,775
General Service 1000 to 4,999 kW														
Customers	5	5	4	4	5	5	5	5	5	5	5	5		5
kWh	24,099,432	25,721,661	33,212,587	30,725,657	27,961,217	37,885,731	39,368,359	42,470,244	48,528,024	51,432,197	51,108,488	50,613,209		47,565,484
kW	86,247	90,065	68,832	67,494	72,545	83,945	85,844	89,307	103,015	110,732	109,361	108,301		99,709
Street Lights														
Customers	942	942	942	942	900	900	899	898	900	905	905	905		905
kWh	728,596	731,832	727,707	748,942	738,099	720,757	713,439	715,663	718,528	720,704	723,044	725,392		720,792
kW	1,998	2,010	2,007	2,048	2,026	1,981	1,964	1,963	1,978	1,983	1,988	1,995		1,984
Sentinel Lights														
Customers	23	23	24	34	31	28	28	28	28	28	29	29		28
kWh	39,379	38,909	38,081	36,606	33,138	31,636	28,024	26,093	26,093	25,478	24,275	23,128		25,020
kW	109	108	106	103	93	88	82	72	72	71	68	65		69
Unmetered Loads														
Connections	13	13	10	3	2	1	1	1	2	1	1	1		1
kWh	101,904	101,877	82,586	20,724	7,536	9,732	7,536	7,563	5,733	5,733	4,164	3,024		5,733
Total														
Customer/Connections	4,354	4,400	4,432	4,490	4,486	4,526	4,553	4,574	4,607	4,641	4,672	4,704		4,663
kWh	92,239,845	93,628,881	95,248,613	93,522,520	86,446,481	96,062,450	99,140,087	101,548,388	103,789,320	105,637,369	104,033,470	105,332,916		105,811,007
kW from applicable classes	133,901	143,317	143,206	143,463	139,624	148,119	153,460	158,734	158,799	160,470	156,066	153,723		157,538

Load Forecast – Regression Statistics:

SUMMARY OUTPUT

Regression Statistics	
Multiple R	94.72%
R Square	89.71%
Adjusted R Square	89.07%
Standard Error	251249.7981
Observations	120

ANOVA

	df	SS	MS	F	Significance F
Regression	7	6.16396E+13	8.80566E+12	139.4923744	2.89422E-52
Residual	112	7.07016E+12	63126461054		
Total	119	6.87098E+13			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	(2181489.7094)	1406278.75	(1.5512)	0.123663037	-4967850.789	604871.3702	-4967850.789	604871.3702
Heating Degree Day	2621.1051	115.6186232	22.6703	1.17134E-43	2392.02157	2850.188532	2392.02157	2850.188532
Cooling Degree Day	8555.5471	1260.593355	6.7869	5.71619E-10	6057.842962	11053.25125	6057.842962	11053.25125
Number of Days in Month	128110.5338	31432.25161	4.0758	8.60072E-05	65831.55634	190389.5112	65831.55634	190389.5112
Number of Peak Hours	4861.7535	1403.102061	3.4650	0.000752477	2081.686595	7641.820348	2081.686595	7641.820348
Regional Employment	3772.8320	1893.083576	1.9930	0.048698006	21.92960755	7523.73449	21.92960755	7523.73449
Sensitive Customers (Purchased kWh)	0.6270	0.064843584	9.6694	1.91377E-16	0.498521827	0.755480327	0.498521827	0.755480327
Trend Variable 3-EProbe-13	2371.3050	1065.15184	2.2263	0.027998176	260.8431819	4481.76685	260.8431819	4481.76685

Load Forecast – Actual kWh Purchases versus Predicted kWh Purchases:

Year	kWh Purchased	year over year	Predicted
2005	99,177,534.70		100,203,868.40
2006	99,726,774.81	0.55%	99,566,096.63
2007	101,905,199.30	2.14%	101,456,606.45
2008	100,510,260.57	-1.39%	99,715,122.48
2009	93,415,381.52	-7.59%	96,051,560.59
2010	102,608,264.83	8.96%	101,470,115.44
2011	105,625,698.07	2.86%	104,257,827.33
2012	108,411,816.52	2.57%	105,015,880.22
2013	110,314,059.50	1.72%	111,948,345.57
2014	112,420,511.95	1.87%	114,430,078.65

Year	kWh Purchased	Predicted	Difference
2005	99,177,534.70	100,203,868.40	1.03%
2006	99,726,774.81	99,566,096.63	0.16%
2007	101,905,199.30	101,456,606.45	0.44%
2008	100,510,260.57	99,715,122.48	0.79%
2009	93,415,381.52	96,051,560.59	2.82%
2010	102,608,264.83	101,470,115.44	1.11%
2011	105,625,698.07	104,257,827.33	1.30%
2012	108,411,816.52	105,015,880.22	3.13%
2013	110,314,059.50	111,948,345.57	1.48%
2014	112,420,511.95	114,430,078.65	1.79%
Mean Average Percentage Error (Mape) :			**1.41%**
Median			**1.20%**

Year	kWh Forecasted Purchases	year over year
2015	111,874,945.40	-0.49%
2016	114,314,469.04	2.18%

G. Cost Allocation Model

Cost Allocation Model – Sheet I6.1: Revenue

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0110

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	105,332,916
Total kWs from Load Forecast	153,723
Deficiency/sufficiency (RRWF 8. cell F52)	(162,171)
Miscellaneous Revenue (RRWF 5. cell F48)	130,105

			1	2	3	5	7	8	9
Billing Data	ID	Total	Residential	GS <50	General Service 50 - 999 kW	General Service 1000 - 4999 kW	Street Light	Sentinel Lighting	Unmetered Scattered Load
Forecast kWh	CEN	105,332,916	27,408,200	12,494,682	14,065,279	50,613,209	725,392	23,128	3,024
Forecast kW	CDEM	153,723			43,362	108,301	1,995	65	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		12,855			12,855				
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-							
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	105,332,916	27,408,200	12,494,682	14,065,279	50,613,209	725,392	23,128	3,024
Existing Monthly Charge			$18.49	$39.25	$275.90	$2,254.94	$7.12	$5.24	$18.09
Existing Distribution kWh Rate			$0.0185	$0.0168					$0.0146
Existing Distribution kW Rate					$3.6643	$1.8921	$7.9283	$19.3776	
Existing TOA Rate					$0.60				
Additional Charges									
Distribution Revenue from Rates		$2,384,615	$1,228,348	$433,883	$284,903	$340,213	$93,908	$3,099	$261
Transformer Ownership Allowance		$7,713	$0	$0	$7,713	$0	$0	$0	$0
Net Class Revenue	CREV	$2,376,902	$1,228,348	$433,883	$277,190	$340,213	$93,908	$3,099	$261

Cost Allocation Model – Sheet I6.2: Customer Data

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0110

Sheet I6.2 Customer Data Worksheet -

			1	2	3	5	7	8	9
	ID	Total	Residential	GS <50	General Service 50 - 999 kW	General Service 1000 - 4999 kW	Street Light	Sentinel Lighting	Unmetered Scattered Load
Billing Data									
Bad Debt 3 Year Historical Average	BDHA	$163,824	$131,059	$9,829	$22,935	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$27,012	$22,960.40	$ 3,511.59	$ 540.24				
Number of Bills	CNB	45,497	39,010	5,706	457	60	36	216	12
Number of Devices	CDEV						914		
Number of Connections (Unmetered)	CCON	-					-	-	-
Total Number of Customers	CCA	3,803	3,250.84	476	38	5	3	29	1
Bulk Customer Base	CCB	-							
Primary Customer Base	CCP	3,880	3,251	476	38	5	80	29	1
Line Transformer Customer Base	CCLT	3,875	3,251	476	38	-	80	29	1
Secondary Customer Base	CCS	3,803	3,251	476	38	5	3	29	1
Weighted - Services	CWCS	3,909	3,251	476	152	30	-	-	-
Weighted Meter -Capital	CWMC	659,359	381,941	233,307	31,120	12,990	-	-	-
Weighted Meter Reading	CWMR	4,034	3,190	710	114	20	-	-	-
Weighted Bills	CWNB	48,949	39,010	8,559	914	240	31	184	12

Bad Debt Data

Historic Year:	2012	162,755	130,204	9,765	22,786				
Historic Year:	2013	163,157	130,525	9,789	22,842				
Historic Year:	2014	165,561	132,449	9,934	23,179				
Three-year average		**163,824**	**131,059**	**9,829**	**22,935**	-	-	-	-

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	**4 NCP**	**Customers/ Devices**	**4 NCP**
Residential	3,251	26,821	3,251	26,821
Street Light	914	663	914	663

Street Lighting	
Primary	11.3721
Line Transformer	11.3721

Cost Allocation Model – Sheet O1: Revenue to Cost

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0110

Sheet O1 Revenue to Cost Summary Worksheet -

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

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 General Service 50 - 999 kW	5 General Service 1000 - 4999 kW	7 Street Light	8 Sentinel Lighting	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$2,376,902	$1,228,348	$433,883	$277,190	$340,213	$93,908	$3,099	$261
mi	Miscellaneous Revenue (mi)	$130,105	$88,239	$20,347	$6,554	$14,002	$528	$415	$19
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$2,507,007	$1,316,587	$454,230	$283,744	$354,215	$94,436	$3,515	$281
	Factor required to recover deficiency (1 + D)	1.0682							
	Distribution Revenue at Status Quo Rates	$2,539,073	$1,312,156	$463,486	$296,102	$363,425	$100,315	$3,311	$279
	Miscellaneous Revenue (mi)	$130,105	$88,239	$20,347	$6,554	$14,002	$528	$415	$19
	Total Revenue at Status Quo Rates	$2,669,178	$1,400,395	$483,833	$302,656	$377,427	$100,843	$3,726	$298
	Expenses								
di	Distribution Costs (di)	$517,000	$262,442	$59,391	$48,477	$140,476	$5,045	$1,130	$39
cu	Customer Related Costs (cu)	$498,500	$378,308	$100,396	$14,513	$3,640	$206	$1,358	$79
ad	General and Administration (ad)	$721,409	$447,419	$112,000	$46,863	$109,322	$3,987	$1,737	$81
dep	Depreciation and Amortization (dep)	$365,779	$186,062	$56,731	$33,371	$85,866	$3,081	$644	$22
INPUT	PILs (INPUT)	$0	$0	$0	$0	$0	$0	$0	$0
INT	Interest	$219,027	$110,386	$29,312	$21,870	$54,860	$2,151	$432	$15
	Total Expenses	$2,321,714	$1,384,617	$357,831	$165,094	$394,164	$14,470	$5,302	$236
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$347,464	$175,117	$46,501	$34,695	$87,029	$3,412	$686	$24
	Revenue Requirement (includes NI)	$2,669,178	$1,559,734	$404,332	$199,789	$481,194	$17,882	$5,988	$260
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$8,067,660	$4,054,279	$1,087,822	$773,347	$2,061,885	$74,348	$15,441	$538
gp	General Plant - Gross	$1,227,114	$614,474	$161,543	$118,409	$318,786	$11,445	$2,375	$83
accum dep	Accumulated Depreciation	($1,069,247)	($551,401)	($166,819)	($98,481)	($241,429)	($9,143)	($1,908)	($66)
co	Capital Contribution	$40,312	$46,282	$22,167	$29,776	($62,489)	$4,180	$383	$13
	Total Net Plant	$8,265,840	$4,163,634	$1,104,713	$823,052	$2,076,753	$80,831	$16,290	$567
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$14,081,514	$3,685,094	$1,670,589	$1,875,964	$6,749,339	$96,759	$3,356	$413
	OM&A Expenses	$1,736,909	$1,088,169	$271,787	$109,853	$253,438	$9,238	$4,225	$199
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$15,818,423*	*$4,773,263*	*$1,942,376*	*$1,985,817*	*$7,002,777*	*$105,997*	*$7,581*	*$612*
	Working Capital	$1,186,382	$357,995	$145,678	$148,936	$525,208	$7,950	$569	$46
	Total Rate Base	$9,452,221	$4,521,629	$1,250,391	$971,988	$2,601,961	$88,780	$16,859	$613
		Rate Base Input equals Output							
	Equity Component of Rate Base	$3,780,888	$1,808,651	$500,157	$388,795	$1,040,784	$35,512	$6,744	$245
	Net Income on Allocated Assets	$347,464	$15,778	$126,002	$137,561	($16,738)	$86,374	($1,576)	$62
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$347,464	$15,778	$126,002	$137,561	($16,738)	$86,374	($1,576)	$62
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	89.78%	119.66%	151.49%	78.44%	563.95%	62.23%	114.67%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($162,171)	($243,147)	$49,898	$83,954	($126,979)	$76,555	($2,473)	$20
		Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($159,339)	$79,501	$102,866	($103,767)	$82,962	($2,262)	$38
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.19%	0.87%	25.19%	35.38%	-1.61%	243.22%	-23.37%	25.32%

Cost Allocation Model – Sheet O2: Fixed Charge |Floor|Ceiling

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0110

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	5	7	8	9
Summary	Residential	GS <50	General Service 50 - 999 kW	General Service 1000 - 4999 kW	Street Light	Sentinel Lighting	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$8.65	$19.75	$27.65	-$1.01	-$0.63	$2.89	$4.83
Customer Unit Cost per month - Directly Related	$14.31	$31.04	$46.02	$43.97	$2.80	$5.07	$8.36
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$28.25	$46.15	$81.80	$204.32	$180.52	$16.75	$21.16
Existing Approved Fixed Charge	$18.49	$39.25	$275.90	$2,254.94	$7.12	$5.24	$18.09

H. Retail Transmission Service Rates

2016 RTSR - Applicant

Ontario Energy Board

v 4.0

2016 RTSR Workform for Electricity Distributors

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

Utility Name	Wellington North Power Inc.
Service Territory	
Assigned EB Number	EB-2015-0110
Name and Title	Richard Bucknall, CAO
Phone Number	1-519-323-1710
Email Address	rbucknall@wellingtonnorthpower.com
Date	January 27th 2015
Last COS Re-based Year	**2012**

2016 RTSR – Applicant's Rate Classes

Ontario Energy Board

v 4.0

2016 RTSR Workform for Electricity Distributors

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	0.0067	0.0042
General Service Less Than 50 kW	kWh	0.0062	0.0035
General Service 50 to 999 kW	kW	2.5395	1.4209
General Service 1,000 to 4,999 kW	kW	2.6973	1.5577
Street Lighting	kW	1.9151	1.0986
Sentinel Lighting	kW	1.9248	1.1215
Unmetered Scattered Load	kWh	0.0062	0.0035
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			

2016 RTSR – RRR Data (2014)

Ontario Energy Board

v 4.0

2016 RTSR Workform for Electricity Distributors

Rate Class	Rate Description	Unit	Rate	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor eg: (1.0325)	Loss Adjusted Billed kWh
Residential	RTSR - Network	kWh	0.0067	25,941,256		1.0716	27,798,650
Residential	RTSR - Connection	kWh	0.0042	25,941,256		1.0716	27,798,650
General Service Less Than 50 kW	RTSR - Network	kWh	0.0062	11,877,868		1.0716	12,728,323
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0035	11,877,868		1.0716	12,728,323
General Service 50 to 999 kW	RTSR - Network	kW	2.5395	15,634,133	47,685		
General Service 50 to 999 kW	RTSR - Connection	kW	1.4209	15,634,133	47,685		
General Service 1,000 to 4,999 kW	RTSR - Network	kW	2.6973	51,432,197	110,732		
General Service 1,000 to 4,999 kW	RTSR - Connection	kW	1.5577	51,432,197	110,732		
Street Lighting	RTSR - Network	kW	1.9151	720,704	1,983		
Street Lighting	RTSR - Connection	kW	1.0986	720,704	1,983		
Sentinel Lighting	RTSR - Network	kW	1.9248	25,478	71		
Sentinel Lighting	RTSR - Connection	kW	1.1215	25,478	71		
Unmetered Scattered Load	RTSR - Network	kWh	0.0062	5,733		1.0716	6,143
Unmetered Scattered Load	RTSR - Connection	kWh	0.0035	5,733		1.0716	6,143

2016 RTSR – UTRs and Sub-Transmission Rates

Ontario Energy Board

v 4.0

2016 RTSR Workform for Electricity Distributors

Uniform Transmission Rates	Unit	Effective January 1, 2014	Effective January 1, 2015	Effective January 1, 2016
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.82	$ 3.78	$ 3.66
Line Connection Service Rate	kW	$ 0.82	$ 0.86	$ 0.87
Transformation Connection Service Rate	kW	$ 1.98	$ 2.00	$ 2.02

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2014 to April 30, 2015	Effective May 1, 2015	Effective January 1, 2016
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.23	$ 3.41	$ 3.41
Line Connection Service Rate	kW	$ 0.65	$ 0.79	$ 0.79
Transformation Connection Service Rate	kW	$ 1.62	$ 1.80	$ 1.80
Both Line and Transformation Connection Service Rate	kW	$ 2.27	$ 2.59	$ 2.59

2016 RTSR – Historical Wholesale

Ontario Energy Board v 4.0

2016 RTSR Workform for Electricity Distributors

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	17,566	$3.23	$ 56,737	7,687	$0.70	$ 5,381	17,566	$1.63	$ 28,687	$ 34,068
February	18,253	$3.23	$ 58,957	7,850	$0.70	$ 5,495	18,253	$1.63	$ 29,806	$ 35,301
March	18,443	$3.23	$ 59,571	7,827	$0.70	$ 5,479	18,443	$1.63	$ 30,113	$ 35,592
April	17,586	$3.22	$ 56,589	7,626	$0.70	$ 5,338	17,586	$1.63	$ 28,717	$ 34,056
May	16,034	$3.23	$ 51,789	7,212	$0.70	$ 5,048	16,034	$1.63	$ 26,191	$ 31,239
June	15,979	$3.41	$ 54,522	7,493	$0.72	$ 5,395	15,979	$1.74	$ 27,729	$ 33,123
July	16,053	$3.41	$ 54,774	7,250	$0.72	$ 5,220	16,053	$1.74	$ 27,896	$ 33,116
August	16,753	$3.41	$ 57,163	7,461	$0.72	$ 5,372	16,753	$1.74	$ 29,128	$ 34,499
September	17,085	$3.41	$ 58,295	7,586	$0.72	$ 5,462	17,085	$1.74	$ 29,708	$ 35,169
October	17,210	$3.41	$ 58,722	7,474	$0.72	$ 5,381	17,210	$1.74	$ 29,949	$ 35,330
November	15,458	$3.37	$ 52,058	7,038	$0.72	$ 5,068	15,458	$1.74	$ 26,855	$ 31,922
December	16,390	$3.41	$ 55,925	7,171	$0.72	$ 5,163	16,390	$1.74	$ 28,515	$ 33,678
Total	202,809	$ 3.33	$ 675,102	89,674	$ 0.71	$ 63,801	202,809	$ 1.69	$ 343,292	$ 407,093

2016 RTSR – Current Wholesale

Ontario Energy Board v 4.0

2016 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when current 2015 Uniform Transmission Rates are applied against historical 2014 transmission units.

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	17,566	$ 3.4121	$ 59,935	7,687	$ 0.7879	$ 6,056	17,566	$ 1.8018	$ 31,650	$ 37,706
February	18,253	$ 3.4121	$ 62,281	7,850	$ 0.7879	$ 6,185	18,253	$ 1.8018	$ 32,888	$ 39,074
March	18,443	$ 3.4121	$ 62,930	7,827	$ 0.7879	$ 6,167	18,443	$ 1.8018	$ 33,231	$ 39,398
April	17,586	$ 3.4121	$ 60,004	7,626	$ 0.7879	$ 6,008	17,586	$ 1.8018	$ 31,686	$ 37,694
May	16,034	$ 3.4121	$ 54,708	7,212	$ 0.7879	$ 5,682	16,034	$ 1.8018	$ 28,889	$ 34,571
June	15,979	$ 3.4121	$ 54,522	7,493	$ 0.7879	$ 5,903	15,979	$ 1.8018	$ 28,791	$ 34,695
July	16,053	$ 3.4121	$ 54,774	7,250	$ 0.7879	$ 5,712	16,053	$ 1.8018	$ 28,924	$ 34,637
August	16,753	$ 3.4121	$ 57,163	7,461	$ 0.7879	$ 5,878	16,753	$ 1.8018	$ 30,185	$ 36,064
September	17,085	$ 3.4121	$ 58,295	7,586	$ 0.7879	$ 5,977	17,085	$ 1.8018	$ 30,783	$ 36,760
October	17,210	$ 3.4121	$ 58,722	7,474	$ 0.7879	$ 5,888	17,210	$ 1.8018	$ 31,009	$ 36,897
November	15,458	$ 3.4121	$ 52,745	7,038	$ 0.7879	$ 5,546	15,458	$ 1.8018	$ 27,853	$ 33,398
December	16,390	$ 3.4121	$ 55,925	7,171	$ 0.7879	$ 5,650	16,390	$ 1.8018	$ 29,532	$ 35,182
Total	202,809	$ 3.41	$ 692,005	89,674	$ 0.79	$ 70,654	202,809	$ 1.80	$ 365,421	$ 436,075

2016 RTSR – Forecast Wholesale

Ontario Energy Board v 4.0

2016 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when forecasted 2016 Uniform Transmission Rates are applied against historical 2014 transmission units.

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	17,566	$ 3.4121	$ 59,935	7,687	$ 0.7879	$ 6,056	17,566	$ 1.8018	$ 31,650	$ 37,706
February	18,253	$ 3.4121	$ 62,281	7,850	$ 0.7879	$ 6,185	18,253	$ 1.8018	$ 32,888	$ 39,074
March	18,443	$ 3.4121	$ 62,930	7,827	$ 0.7879	$ 6,167	18,443	$ 1.8018	$ 33,231	$ 39,398
April	17,586	$ 3.4121	$ 60,004	7,626	$ 0.7879	$ 6,008	17,586	$ 1.8018	$ 31,686	$ 37,694
May	16,034	$ 3.4121	$ 54,708	7,212	$ 0.7879	$ 5,682	16,034	$ 1.8018	$ 28,889	$ 34,571
June	15,979	$ 3.4121	$ 54,522	7,493	$ 0.7879	$ 5,903	15,979	$ 1.8018	$ 28,791	$ 34,695
July	16,053	$ 3.4121	$ 54,774	7,250	$ 0.7879	$ 5,712	16,053	$ 1.8018	$ 28,924	$ 34,637
August	16,753	$ 3.4121	$ 57,163	7,461	$ 0.7879	$ 5,878	16,753	$ 1.8018	$ 30,185	$ 36,064
September	17,085	$ 3.4121	$ 58,295	7,586	$ 0.7879	$ 5,977	17,085	$ 1.8018	$ 30,783	$ 36,760
October	17,210	$ 3.4121	$ 58,722	7,474	$ 0.7879	$ 5,888	17,210	$ 1.8018	$ 31,009	$ 36,897
November	15,458	$ 3.4121	$ 52,745	7,038	$ 0.7879	$ 5,546	15,458	$ 1.8018	$ 27,853	$ 33,398
December	16,390	$ 3.4121	$ 55,925	7,171	$ 0.7879	$ 5,650	16,390	$ 1.8018	$ 29,532	$ 35,182
Total	202,809	$ 3.41	$ 692,005	89,674	$ 0.79	$ 70,654	202,809	$ 1.80	$ 365,421	$ 436,075

2016 RTSR – Rates to Forecast

Ontario Energy Board

v 4.0

2016 RTSR Workform for Electricity Distributors

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Rate Description	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
Residential	RTSR - Network	kWh	0.0067	27,798,650		186,251	27.0%	187,087	0.0067
General Service Less Than 50 kW	RTSR - Network	kWh	0.0062	12,728,323		78,916	11.5%	79,270	0.0062
General Service 50 to 999 kW	RTSR - Network	kW	2.5395		47,685	121,096	17.6%	121,640	2.5509
General Service 1,000 to 4,999 kW	RTSR - Network	kW	2.6973		110,732	298,677	43.4%	300,018	2.7094
Street Lighting	RTSR - Network	kW	1.9151		1,983	3,798	0.6%	3,815	1.9237
Sentinel Lighting	RTSR - Network	kW	1.9248		71	137	0.0%	137	1.9334
Unmetered Scattered Load	RTSR - Network	kWh	0.0062	6,143		38	0.0%	38	0.0062

The purpose of this table is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Rate Description	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR-Connection
Residential	RTSR - Connection	kWh	0.0042	27,798,650		116,754	28.9%	126,078	0.0045
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0035	12,728,323		44,549	11.0%	48,107	0.0038
General Service 50 to 999 kW	RTSR - Connection	kW	1.4209		47,685	67,756	16.8%	73,167	1.5344
General Service 1,000 to 4,999 kW	RTSR - Connection	kW	1.5577		110,732	172,487	42.7%	186,262	1.6821
Street Lighting	RTSR - Connection	kW	1.0986		1,983	2,179	0.5%	2,352	1.1863
Sentinel Lighting	RTSR - Connection	kW	1.1215		71	80	0.0%	86	1.2111
Unmetered Scattered Load	RTSR - Connection	kWh	0.0035	6,143		22	0.0%	23	0.0038

The purpose of this table is to update the re-aligned RTS Network Rates to recover future wholesale network costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Network
Residential	RTSR - Network	kWh	0.0067	27,798,650		187,087	27.0%	187,087	**0.0067**
General Service Less Than 50 kW	RTSR - Network	kWh	0.0062	12,728,323		79,270	11.5%	79,270	**0.0062**
General Service 50 to 999 kW	RTSR - Network	kW	2.5509		47,685	121,640	17.6%	121,640	**2.5509**
General Service 1,000 to 4,999 kW	RTSR - Network	kW	2.7094		110,732	300,018	43.4%	300,018	**2.7094**
Street Lighting	RTSR - Network	kW	1.9237		1,983	3,815	0.6%	3,815	**1.9237**
Sentinel Lighting	RTSR - Network	kW	1.9334		71	137	0.0%	137	**1.9334**
Unmetered Scattered Load	RTSR - Network	kWh	0.0062	6,143		38	0.0%	38	**0.0062**

The purpose of this table is to update the re-aligned RTS Connection Rates to recover future wholesale connection costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Connection
Residential	RTSR - Connection	kWh	0.0045	27,798,650		126,078	28.9%	126,078	**0.0045**
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0038	12,728,323		48,107	11.0%	48,107	**0.0038**
General Service 50 to 999 kW	RTSR - Connection	kW	1.5344		47,685	73,167	16.8%	73,167	**1.5344**
General Service 1,000 to 4,999 kW	RTSR - Connection	kW	1.6821		110,732	186,262	42.7%	186,262	**1.6821**
Street Lighting	RTSR - Connection	kW	1.1863		1,983	2,353	0.5%	2,353	**1.1863**
Sentinel Lighting	RTSR - Connection	kW	1.2111		71	86	0.0%	86	**1.2111**
Unmetered Scattered Load	RTSR - Connection	kWh	0.0038	6,143		23	0.0%	23	**0.0038**

I. Advanced Capital Module (ACM) for 2018

ACM (2018) - Applicant

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 3.0

Utility Name	Wellington North Power Inc.		
Service Territory (if filing more than one model)			
Assigned EB Number	EB-2015-0110		
Name of Contact and Title	Richard Bucknall, CAO		
Phone Number	1-519-323-1710		
Email Address	rbucknall@wellingtonnorthpower.com		
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	COS	Rate Year	2016
Wellington North Power Inc. is applying for:	ACM Approval		
Last COS OEB Application Number			
Indicate the most recent complete year in which billing and load data exists	2014		
Current IPI	2.10%		
Strech Factor Assigned to Middle Cohort	III		
Stretch Factor Value	0.30%		
Price Cap Index	1.80%		

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{2016 Test Year Distribution Revenues}}{\text{2014 Actual Distribution Revenues}}$$

Notes

ACM (2018) – Applicant's rate Classes

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Wellington North Power Inc.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **7**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 KW
3	GENERAL SERVICE 50 TO 999 KW
4	GENERAL SERVICE 1,000 TO 4,999 KW
5	UNMETERED SCATTERED LOAD
6	SENTINEL LIGHTING
7	STREET LIGHTING

ACM (2018) – Growth Factor

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Wellington North Power Inc.

Input the billing determinants and base distribution rates associated with Wellington North Power Inc.'s 2016 Test Year Distribution Revenues. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2016 Test Year Distribution Revenues			2016 Test Year Distribution Revenues		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	3,251	27,408,200		23.97	0.0153	0.0000
GENERAL SERVICE LESS THAN 50 KW	$/kWh	476	12,494,682		41.71	0.0179	0.0000
GENERAL SERVICE 50 TO 999 KW	$/kW	38	14,065,279	43,362	275.90	0.0000	2.6315
GENERAL SERVICE 1,000 TO 4,999 KW	$/kW	5	50,613,209	108,301	2254.94	0.0000	3.0505
UNMETERED SCATTERED LOAD	$/kWh	1	3,024		28.33	0.0156	0.0000
SENTINEL LIGHTING	$/kW	29	23,128	65	7.38	0.0000	27.3041
STREET LIGHTING	$/kW	905	725,392	1,995	1.60	0.0000	1.7664

ACM (2018) – Growth Factor Calculation

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Wellington North Power Inc.

Calculation of 2016 Revenue Requirement. No input required.

Rate Class	2016 Test Year Distribution Revenues: Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenue Requirement from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G = A * D *12	H = B * E	I = C * F	J = G + H + I	K = G / J	L = H / J	M = I / J	N = J / R
RESIDENTIAL	3,251	27,408,200		23.97	0.0153	0.0000	935,118	419,270	0	1,354,387	69.0%	31.0%	0.0%	53.2%
GENERAL SERVICE LESS THAN 50 KW	476	12,494,682		41.71	0.0179	0.0000	238,255	223,074	0	461,328	51.6%	48.4%	0.0%	18.1%
GENERAL SERVICE 50 TO 999 KW	38	14,065,279	43,362	275.90	0.0000	2.6315	125,810	0	114,108	239,918	52.4%	0.0%	47.6%	9.4%
GENERAL SERVICE 1,000 TO 4,999 KW	5	50,613,209	108,301	2,254.94	0.0000	3.0505	135,296	0	330,370	465,666	29.1%	0.0%	70.9%	18.3%
UNMETERED SCATTERED LOAD	1	3,024		28.33	0.0156	0.0000	340	47	0	387	87.8%	12.2%	0.0%	0.0%
SENTINEL LIGHTING	29	23,128	65	7.38	0.0000	27.3041	2,569	0	1,775	4,344	59.1%	0.0%	40.9%	0.2%
STREET LIGHTING	905	725,392	1,995	1.60	0.0000	1.7664	17,398	0	3,524	20,922	83.2%	0.0%	16.8%	0.8%
Total	**4,705**	**105,332,914**	**153,723**				**1,454,787**	**642,391**	**449,776**	**2,546,954**				**100.0%**

ACM (2018) – Revenue Requirement Check

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

	2016 Test Year Distribution Revenues					
Applicants Rate Base						
Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	15,033,156	A			
Add: CWIP Re-based Opening			B			
Re-based Capital Additions	$	1,593,911	C			
Re-based Capital Disposals			D			
Re-based Capital Retirements	-$	27,635	E			
Deduct: CWIP Re-based Closing			F			
Gross Fixed Assets - Re-based Closing	$	16,599,432	G			
Average Gross Fixed Assets				$	15,816,294	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	7,349,346	I			
Re-based Depreciation Expense	$	365,779	J			
Re-based Disposals	-$	11,200	K			
Re-based Retirements			L			
Accumulated Depreciation - Re-based Closing	$	7,703,924	M			
Average Accumulated Depreciation				$	7,526,635	N = (I + M) / 2
Average Net Fixed Assets				**$**	**8,289,659**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	15,818,423	P			
Working Capital Allowance Rate		7.5%	Q			
Working Capital Allowance				**$**	**1,186,382**	R = P * Q
Rate Base				**$**	**9,476,041**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	379,042	W = S * T
Deemed Long Term Debt %		56.00%	U	$	5,306,583	X = S * U
Deemed Equity %		40.00%	V	$	3,790,416	Y = S * V
Short Term Interest		1.65%	Z	$	6,254	AC = W * Z
Long Term Interest		4.02%	AA	$	213,325	AD = X * AA
Return on Equity		9.19%	AB	$	348,339	AE = Y * AB
Return on Rate Base				**$**	**567,918**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	1,736,909	AG			
Amortization	$	365,779	AH			
Ontario Capital Tax			AI			
Grossed Up PILs	$	-	AJ			
Low Voltage			AK			
Transformer Allowance	$	7,713	AL			
			AM			
			AN			
			AO			
				$	**2,110,401**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	58,297	AQ			
Late Payment Charges	-$	29,000	AR			
Other Distribution Income	-$	61,308	AS			
Other Income and Deductions	$	18,500	AT	**-$**	**130,105**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**2,548,214**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (Sheet 5)				$	2,546,954	AW
Difference				$	1,260	AZ = AV - AW
Difference (Percentage - should be less than 1%)					0.05%	BA = AZ / AW

ACM (2018) – Growth Factor Denominator Calculation

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Wellington North Power Inc.

Input the billing determinants associated with Wellington North Power Inc.'s 2014 Actual Distribution Revenues. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pseudo Revenue Requirement Calculation.

	2014 Actual Distribution Revenues			2014 Base Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G = A * D *12	H = B * E	I = C * F	J = G + H + I	K = G / J_{total}	L = H / J_{total}	M = I / J_{total}	N = J / J_{total}
RESIDENTIAL	3,213	25,720,644		23.97	0.0153	0.0000	924,187	393,455	0	1,317,642	36.9%	15.7%	0.0%	52.6%
GENERAL SERVICE LESS THAN 50 KW	478	11,853,213		41.71	0.0179	0.0000	239,256	211,621	0	450,877	9.6%	8.4%	0.0%	18.0%
GENERAL SERVICE 50 TO 999 KW	35	13,388,357	47,573	275.90	0.0000	2.6315	115,878	0	125,190	241,068	4.6%	0.0%	5.0%	9.6%
GENERAL SERVICE 1,000 TO 4,999 KW	5	53,572,575	109,682	2,254.94	0.0000	3.0505	135,296	0	334,583	469,879	5.4%	0.0%	13.4%	18.8%
UNMETERED SCATTERED LOAD	1	5,733		28.33	0.0156	0.0000	340	89	0	429	0.0%	0.0%	0.0%	0.0%
SENTINEL LIGHTING	29	25,409	71	7.38	0.0000	27.3041	2,569	0	1,928	4,497	0.1%	0.0%	0.1%	0.2%
STREET LIGHTING	905	720,792	1,983	1.60	0.0000	1.7664	17,398	0	3,503	20,901	0.7%	0.0%	0.1%	0.8%
Total	**4,666**	**105,286,723**	**159,309**				**1,434,925**	**605,166**	**465,203**	**2,505,294**				**100.0%**

ACM (2018) – Rate Class Revenue Proportions

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Wellington North Power Inc.

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Proposed Base Rates in Current CoS			2016 Test Year Distribution Revenues										
Rate Class	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
	A	B	C	D	E	F	G = A * D *12	H = B * E	I = C * F	J = G + H + I	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	$O = J / J_{total}$
RESIDENTIAL	18.00	0.0180	0.0000	3,251	27,408,200		702,216	493,348	0	1,195,564	30.25%	21.25%	0.00%	51.5%
GENERAL SERVICE LESS THAN 50 KW	38.21	0.0164	0.0000	476	12,494,682		218,256	204,913	0	423,168	9.40%	8.83%	0.00%	18.2%
GENERAL SERVICE 50 TO 999 KW	268.64	0.0000	3.5679	38	14,065,279	43,362	122,500	0	154,711	277,211	5.28%	0.00%	6.67%	11.9%
GENERAL SERVICE 1,000 TO 4,999 KW	2195.63	0.0000	1.8423	5	50,613,209	108,301	131,738	0	199,523	331,261	5.68%	0.00%	8.60%	14.3%
UNMETERED SCATTERED LOAD	17.61	0.0142	0.0000	1	3,024		211	43	0	254	0.01%	0.00%	0.00%	0.0%
SENTINEL LIGHTING	5.11	0.0000	18.8680	29	23,128	65	1,778	0	1,226	3,005	0.08%	0.00%	0.05%	0.1%
STREET LIGHTING	6.93	0.0000	7.7198	905	725,392	1,995	75,260	0	15,401	90,661	3.24%	0.00%	0.66%	3.9%
Total							**1,251,959**	**698,303**	**370,862**	**2,321,124**				**100.0%**

ACM (2018) – Threshold Test

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Wellington North Power Inc.

No Input Required.

Preliminary Threshold Calculation

$$\textit{Threshold Value}\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Year		**2016**	
Year in which Applicant is applying		**COS**	n
Price Cap Index		**1.80%**	PCI
Growth Factor Calculation			
2016 Test Year Distribution Revenues		$2,546,954	
2014 Actual Distribution Revenues		$2,505,294	
Growth Factor		**0.83%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	15,033,156	
Add: CWIP Opening	$	-	
Capital Additions	$	1,593,911	
Capital Disposals	$	-	
Capital Retirements	-$	27,635	
Deduct: CWIP Closing	$	-	
Gross Fixed Assets - Closing	$	16,599,432	
Average Gross Fixed Assets	$	15,816,294	
Accumulated Depreciation - Opening	$	7,349,346	
Depreciation Expense	$	365,779	
Disposals	-$	11,200	
Retirements	$	-	
Accumulated Depreciation - Closing	$	7,703,924	
Average Accumulated Depreciation	$	7,526,635	
Average Net Fixed Assets	$	8,289,659	
Working Capital Allowance			
Working Capital Allowance Base	$	15,818,423	
Working Capital Allowance Rate		8%	
Working Capital Allowance	$	1,186,382	
Rate Base	**$**	**9,476,041**	RB
Depreciation	**$**	**365,779**	d
Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)			
Price Cap IR Year 2017		**179%**	
Price Cap IR Year 2018		**180%**	
Price Cap IR Year 2019		**182%**	
Price Cap IR Year 2020		**184%**	
Threshold CAPEX			$\textit{Threshold Value} \times d$
Price Cap IR Year 2017	**$**	**653,131**	
Price Cap IR Year 2018	**$**	**659,768**	
Price Cap IR Year 2019	**$**	**666,580**	
Price Cap IR Year 2020	**$**	**673,572**	

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

ACM (2018) – Proposed ACM Project: Substation Replacement

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Wellington North Power Inc.

Identify ALL Proposed ACM projects and related CAPEX costs in the relevant years

	Cost of Service Test Year 2016	Price Cap IR Year 1 2017	Year 2 2018	Year 3 2019	Year 4 2020
Distribution System Plan CAPEX	$ 1,593,911	$ 768,670	$ 2,196,470	$ 951,850	$ 963,000
Materiality Threshold		$ 653,131	$ 659,768	$ 666,580	$ 673,572
Maximum Eligible Incremental Capital (Forecasted CAPEX less Threshold)		$ 115,539	$ 1,536,702	$ 285,270	$ 289,428
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ 115,539	$ 1,536,702	$ 285,270	$ 289,428

Proposed Capital Projects Eligible for ACM treatment

Project Descriptions:	Cost of Service Test Year 2016	Price Cap IR Year 1 2017	Year 2 2018	Year 3 2019	Year 4 2020	Total
Replacement Substation MS3 including Recloser Smart Technology			$ 1,672,000			$ 1,672,000
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
Maximum Allowed Incremental Capital		$ -	$ 1,536,702	$ -	$ -	

J. Draft Accounting Order - OPEBs

Draft Accounting Order – OPEB Forecast Cash versus Forecast Accrual Differential Deferral / Variance Account

WNP shall establish the following deferral account effective January 1, 2016.

Account 1508 Other Regulatory Assets, Subaccount – OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account WNP shall establish the OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account for the purpose of recording the difference in revenue requirement each year between both the capitalized and OM&A components of OPEBs accounted for using a forecasted cash basis (as to be reflected in rates if this settlement is accepted by the OEB) and the capitalized and OM&A components of OPEBs accounted for using a forecasted accrual basis.

If the OEB determines that LDCs must only include in rates OPEBs accounted for using a forecasted cash basis, WNP will seek to discontinue this account without seeking disposition of the amounts recorded in this account. If the OEB determines that LDCs may recover OPEBs in rates using a forecasted accrual accounting methodology, WNP will seek disposition of this account to recover the amounts so recorded in its next cost of service rate application.

WNP will propose a disposition period over which the account should be recovered depending on the quantum in the account and the potential rate impacts at the time.

Carrying charges will not apply to this account.

<u>Sample Journal Entry</u>

Assumptions:

- OPEB costs (accrual basis) = $ 568
- OPEB costs (cash basis) = $ 12,568
- OBEB costs split between operating and capital on a 90/10 ratio.
- Assume capital items depreciated over 40 years and half year rule applies in year of acquisition.
- Assume OPEB costs incurred evenly throughout the fiscal period.

The sample accounting entries for the Deferral Account is provided below:

A: To record the excess of OPEBs accounted for using a forecasted accrual basis over OPEBs accounted for using a forecasted cash basis.

DR	Capital costs (various accounts)		$1,200	
DR	OM&A expenses (various accounts)		$10,800	
CR	1508	Other Regulatory Assets, Subaccount – OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account		$ 12,000

B: To reverse depreciation recorded on capital portion of OPEB costs:

DR	Accumulated Depreciation	$15	
CR	Depreciation		$15

K. Draft Accounting Order – CapEx Project: 2nd Line Feeder (2016)

Draft Accounting Order – Second Line Feeder 2016 Capital Project to reflect the 2016 Settlement Proposal

Accounting Order Requested – 1508 Other Regulatory Asset – Second Line Feeder Project.
WNP requests a new variance account 1508 Other Regulatory Asset – Second Line Feeder Project to record the revenue requirement impact of three items:

a) The net change in costs of the capital contributions paid to HONI for the construction of the Second Line Feeder;
b) The net change in costs of the construction required by WNP to integrate the Second Line Feeder Project into the existing distribution system.
c) The impact of either of the above two projects not being completed in 2016

The costs that are included in the 2016 Cost of Service rate application are as follows:

Item	Estimated Cost
HONI 2nd Feeder	$881,156
HONI Study	$32,061
WNP H'way 6 Pole Line	$380,000
PME Meter	$80,000
Total	**$1,373,261**

The OEB's Filing Requirements indicate that in the event an applicant seeks an accounting order to establish a new deferral/variance account, the eligibility criteria must be met, including causation, materiality and prudence. While the materiality of the variances is unknown, the scope of the project as a percentage of WNP's total capital spending is very large. Therefore the eligibility criteria have been met.

In the absence of a general variance account for this purpose, WNP requests that the OEB approve an Accounting Order for WNP as part of this settlement, and that such an Accounting Order include the following:

1) Changes in Capital Contributions paid to HONI to complete the Second Line Feeder Project. The changes in these costs will be recorded as follows:

   Accounting Entry:
   Debit/Credit - Account 1609, Capital Contributions Paid

Credit/Debit - Account 1508, Other Regulatory Asset – Sub-account Second Line Feeder

2) Changes in pole line project costs WNP incurs to integrate the Second Line Feeder Project into the existing distribution system;

   Accounting Entry:
   Debit/Credit – Asset Account Poles 1830 and Asset Account Meters 1860
   Credit/Debit - Account 1508, Other Regulatory Asset – Sub-account Second Line Feeder

3) The account is symmetrical and will reflect both cost over-runs and lower project costs in both the HONI and WNP components of the project.

4) The balance in the variance account is to be disposed of at WNP's next Cost of Service Filing; and

5) Carrying charges will be applied at the Board's Prescribed Interest

L. CapEx Project: 2nd Line Feeder (2016) – Latest Quote from HONI

Below is confirmation, for the public record, advising of the latest quote from Hydro One Networks Inc. (HONI) received on February 11th 2016:

Wellington North Power Inc.
290 Queen Street West, PO Box 359, Mount Forest, ON N0G 2L0
Phone: 519.323.1710 Fax: 519.323.2425 E-mail:
wnp@wellingtonnorthpower.com
www.wellingtonnorthpower.com

March 4, 2016

Attention: Parties involved with OEB File: EB-2015-0110

Dear Board Staff and Intervenors,

Re: Wellington North Power Inc.
OEB File: EB-2015-0110 - 2016 Cost of Service Application
Hydro One Networks Inc. latest cost estimate for 2nd line feeder construction to Mount Forest

Concerning Wellington North Power's (WNP) 2016 Cost of Service rate application (OEB File EB-2015-0110), the Applicant confirms that the latest quote from Hydro One Networks Inc. (HONI) is:

Capital Contribution Required (from WNP to HONI)	$881,156.14
HST @ 13%	$114,550.30
Total	**$995,706.44**

The Capital Contribution required from WNP is for the design, procurement and construction by HONI of approximately 11 km of a 44kV pole line from Palmerston Transformer Substation M2 to the south end of Mount Forest in 2016. This quote was received by WNP by e-mail on February 11th 2016.

Regards,

Jim Klujber
Chief Operating Officer
Wellington North Power Inc.