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Northern Ontario WIRES Inc.

153 Sixth Avenue – 153 Sixième avenue
P.O. Box 640 – C.P. 640
Cochrane, Ontario P0L 1C0

March 13, 2017

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

Re: 2017 Cost of Service Application EB-2016-0096
Settlement Proposal - Update

Dear Ms. Walli:

Further to my letter of March 9, 2017 regarding submission of a Settlement Proposal, it has been identified that two tables (Table 6 – "Appendix 2-OB Debt Instruments" and Table 7 "Appendix 2-OA Capital Structure and Cost of Capital – per Settlement Agreement") were not the final version of the tables consistent with the Chapter 2 Appendices live model that was also filed. The Long Term Debt amount in the Chapter 2 Appendix live model is correct. Accordingly, NOW Inc. has updated Tables 6 and 7 in the attached Settlement Proposal to reflect the correct Chapter 2 Appendix Long Term Debt amount. Please note that this update does not impact any of the models or rate impacts that were filed on March 9, 2017.

An electronic copy has been submitted through the RESS.

Respectfully Submitted,

Geoffrey Sutton, CPA, CA
Chief Financial Officer
Tel: (705) 272-6669
Email: geoffs@nowinc.ca

Cc: Mark Rubenstein, SEC
Mark Garner, VECC
Lawrie Gluck, OEB
Shelly Grice, AMPCO
Bill Harper, VECC
Michael Buonaguro, Counsel

Northern Ontario Wires Inc.

2017 Cost of Service Application

Settlement Proposal

EB-2016-0096

Filed: March 9, 2017

Contents

LIST OF ATTACHMENTS

1. Revenue Requirement Workform
2. Proposed Tariff Sheet
3. Bill Impacts
4. 2016 and 2017 Fixed Asset Continuity Schedule
5. Accounting Order – OPEB

Note:

Northern Ontario Wires Inc. has filed revised models as evidence to support this Settlement Proposal. The models have been filed through the OEB's e-filing service and include:

a) NOW_2017CoS_Settlement_DVA Continuity Schedule_20170309
b) NOW_2017CoS_Settlement_PILs_20170309
c) NOW_2017CoS_Settlement_Chapter 2_Appendix_20170309
d) NOW_2017CoS_Settlement_Cost Allocation_20170309
e) NOW_2017CoS_Settlement_Load Forecast_20170309
f) NOW_2017CoS_Settlement_RRWF_20170309
g) NOW_2017CoS_Settlement_RTSR_20170309
h) NOW_2017CoS_Settlement_Bill Impact_201703009
i) NOW_2017CoS_Settlement_PEGBNCH_Model_20170309

SETTLEMENT PROPOSAL

Northern Ontario Wires Inc. (the "Applicant" or "NOW") filed a Cost of Service application with the Ontario Energy Board (the "OEB") on August 26, 2016 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 NOW charges for electricity distribution, to be effective May 1, 2017 (OEB file number EB-2016-0096) (the "Application").

The OEB issued a Letter of Direction and Notice of Application on October 20, 2016. In Procedural Order No. 1, dated November 29, 2016, the OEB approved VECC, SEC, and AMPCO for intervenor status as well as prescribing dates for the following: written interrogatories from OEB staff, VECC, SEC, and AMPCO; NOW's responses to interrogatories; a Settlement Conference; and various other elements in the proceeding.

Following the receipt of interrogatories, NOW filed the majority of its interrogatory responses with the OEB on January 31, 2017, with certain responses relating to 2016 year-end actuals being filed on February 17, 2017. Accordingly, the application as presented for settlement reflects actual unaudited 2016 results (reference: 6-Staff-48, 2-Staff-11, 2-SEC-13).

On February 10, 2017, following the filing of interrogatory responses, OEB Staff submitted a proposed issues list as agreed to by the Parties. On February 16, 2017 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").

The settlement conference was convened on February 23 and 24, 2017 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"). Ms. Karen Wianecki acted as facilitator for the Settlement Conference.

NOW and the following intervenors (the "Intervenors"), participated in the Settlement Conference:

- Vulnerable Energy Consumers Coalition ("VECC");
- School Energy Coalition ("SEC").
- Association of Major Power Consumers of Ontario ("AMPCO")

NOW 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 on 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 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 specific rules with respect to confidentiality and privilege set out in the Practice Direction on Settlement Conferences, as amended on October 28, 2016, apply. Parties have interpreted the revised Practice Direction 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 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 issue, as applicable, agree that the evidence in respect of that 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 the Settlement Proposal are Attachments that provide further support for the proposed settlement. The Parties acknowledge that the Attachments were prepared by NOW. While the Intervenors and OEB Staff have reviewed the Attachments, the Intervenors are relying on the accuracy of the Attachments and 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 have reached a full settlement with respect to the issues in this proceeding.

According to the Practice Direction (p.4), 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 not 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 must agree with any revised Settlement Proposal as it relates to that issue, or take no position, 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 the Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not NOW is a party to such proceeding, provided that no Party shall take a position that would result in the Agreement not applying in accordance with the terms contained herein.

Where in this Agreement, the Parties “accept” the evidence of NOW, 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, the Parties have been guided by the Filing Requirements for 2017 rates and the Approved Issues List.

This Settlement Proposal reflects a full settlement of the issues in the proceeding. The Parties have described below, in detail, areas where they have settled an issue by agreeing to adjustments to the Application as updated.

The Parties note that this Settlement Proposal includes all tables, appendices and the live Excel models that represent the evidence and the settlement between the Parties at the time of filing the settlement proposal.

A Revenue Requirement Work Form, incorporating all terms that have been agreed to in this Proposal is filed with the Settlement Proposal. Through the settlement process, NOW has agreed to certain adjustments to its original 2017 Application. The changes are described in the following sections.

NOW has provided the following Table 1 highlighting the changes to its Rate Base and Capital, Operating Expenses and Revenue Requirement from NOW's Application as filed as a result of interrogatories and this Settlement Proposal.

Table 1: Revenue Requirement

Description		Application (A)	IR/TC Responses(B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Cost of Capital	Regulated Return on Capital	468,569	441,435	(27,134)	440,384	(1,051)
	Regulated Rate of Return	6.03%	5.67%	-0.36%	5.67%	0.00%
Rate Base & Capital Expenditures	Rate Base	7,766,288	7,786,168	19,880	7,767,615	(18,553)
	Working Capital	18,892,797	19,613,740	720,943	19,695,996	82,256
	Working Capital Allowance	1,416,960	1,471,030	54,071	1,477,200	6,169
Operating Expenses	Amortization/Depreciation	439,680	439,433	(247)	438,877	(556)
	Grossed Up Income Taxes	16,330	42,771	26,441	42,910	139
	OM&A	2,907,906	2,907,906	0	2,757,906	(150,000)
Revenue Requirement	Service Revenue Requirement	3,832,485	3,831,545	(940)	3,680,077	(151,468)
	Other Revenues	268,918	268,918	0	268,918	0
	Base Revenue Requirement	3,563,567	3,562,627	(940)	3,411,159	(151,468)
	Grossed Up Revenue Deficiency/(Sufficiency)	619,988	582,114	(37,874)	390,087	(192,027)

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

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

Table 2: Bill Impact Summary

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current Rates	Settlement	Change $	Change %
Residential; TOU	750		140.29	140.71	0.43	0.30%
GS<50 kW	2,000		355.91	356.38	0.47	0.13%
GS>50 kW	66,182	195	10,346.59	10,074.61	(271.98)	-2.63%
USL	599		113.04	112.54	(0.49)	-0.44%
Street Lighting	28	0.08	11.59	12.36	0.77	6.62%

RRFE OUTCOMES

The Parties accept the Applicant's compliance with the Board's required outcomes as defined by the Renewed Regulatory Framework for Electricity (RRFE). Subject to the adjustments noted in this Settlement Proposal, the Parties accept that NOW's proposed rates in the 2017 Test Year will, in all reasonably foreseeable circumstances, allow the Applicant to meet its obligations to its customers while maintaining its financial viability.

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.

Full Settlement

Subject to the reduction in the forecast 2017 in-service additions of $50,000 to more appropriately pace NOW's capital plan during the term of the Distribution System Plan, the Parties accept the 2017 capital expenditures as appropriate. NOW has, for illustrative purposes, associated the reduction in forecast in-service additions to the following 2017 projects: Pole Changes – Cochrane ($25,000), Kapuskasing 5kV to 25 kV Conversion Upgrade ($15,000), and Iroquois Falls 2.4 kV to 12kV Upgrade. The Parties understand and agree that NOW has the discretion and responsibility to manage the proposed reduction as it sees fit during the test year.

Table 3: 2017 Gross Capital Expenditures

Category	Application (A)	IR/TC Responses(B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
System Access	15,000	15,000	0	15,000	0
System Renewal	355,000	355,000	0	330,000	(25,000)
System Service	315,000	315,000	0	290,000	(25,000)
General Plant	142,500	142,500	0	142,500	0
Total Expenditure	**827,500**	**827,500**	**0**	**777,500**	**(50,000)**

The Parties accept the evidence of NOW 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.

Table 3.1: Average Net Fixed Assets

Description	Application (A)	IR/TC Response (B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Opening Gross Fixed Assets (2016)	$ 8,083,049	$ 8,049,329	$ (33,720)	$ 8,049,329	$ -
Closing Gross Fixed Assets (2017)	$ 8,910,549	$ 8,876,829	$ (33,720)	$ 8,826,829	$ (50,000)
Average Net Fixed Assets	$ 8,496,799	$ 8,463,079	$ (33,720)	$ 8,438,079	$ (25,000)
Opening Accumulated Depreciation (2016)	$ (1,823,137)	$ (1,823,464)	$ (327)	$ (1,823,464)	$ -
Closing Accumulated Depreciation (2017)	$ (2,471,804)	$ (2,472,419)	$ (615)	$ (2,471,863)	$ 556
Average Accumulated Depreciation	$ (2,147,470)	$ (2,147,941)	$ (471)	$ (2,147,663)	$ 278
Average Net Fixed Assets	$ 6,349,329	$ 6,315,137	$ (34,191)	$ 6,290,415	$ (24,722)

Evidence References

- Exhibit 1/Tab 5/Schedule 4 – Rate Base and DSP
- Exhibit 2/Tab 1/Schedule 1 – Rate Base Overview
- Exhibit 2/Tab 1/Schedule 2 – Rate Base Gross Assets (PP&E)
- Exhibit 2/Tab 2/Schedule 1 – Capital Expenditures Planning (includes DSP)

IR Responses

- 2-Staff-7
- 2-Staff-10 to 2-Staff-27
- 2-SEC-13 to 2-SEC-18
- 2-VECC- 4 to 2-VECC-13; 2-VECC-16 to 2-VECC-18
- 2-AMPCO-2 to 2-AMPCO-4; 2-AMPCO-12-22

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

It is noted that the intervenors take no position with respect to NOW Inc.'s request (Exhibit 1, Tab 3, Schedule 9, pg. 1) for Board approval of the company's DSP.

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.

Full Settlement

The Parties have agreed to a reduction in the applied for total OM&A expenses for 2017 in the amount of $141,291 for the purposes of settlement. The Parties have also agreed that NOW will move to recording OPEB costs on a cash basis rather than its current practice to record them on an accrual basis pending the OEB's decision in EB-2015-0040; the impact of this change in practice is a further reduction of $8,709 in the OM&A Test Year, for a total reduction to OM&A of $150,000. Subject to these changes the Parties accept the evidence of NOW that the level of planned OM&A expenditures for 2017 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.

In agreeing to the adjusted total OM&A the Parties acknowledge the unique challenges the NOW has faced over the period from 2013 to 2016 as a result of having had to absorb a significant loss of revenue in 2013 and the following years as a result of the bankruptcy of a large customer. This event seriously affected NOW's cash flow throughout the period and consequently constrained NOW's ability to operate as it was required to make reductions to its OM&A spending. While NOW was able to continue operating without seeking special relief from the OEB, the result is the need for a larger than inflationary increase in forecast OM&A relative to 2016 when NOW's rates are rebased for the 2017 test year. With the agreed upon adjusted OM&A, NOW is still forecasted to remain in the Board's top efficiency Cohort 1 as per the PEG Benchmark model (which is included with the set of Excel models supporting this Settlement Agreement).

Table 4: 2017 Test Year OM&A Expenditures

Description	Application (A)	IR/TC Responses(B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Operations	815,665	815,665	0	761,627	(54,038)
Maintenance	697,590	697,590	0	621,628	(75,962)
Billing and Collecting	746,564	746,564	0	726,564	(20,000)
Community Relations			0		0
Administrative and General	648,087	648,087	0	648,087	0
Total Expenditure	**2,907,906**	**2,907,906**	**0**	**2,757,906**	**(150,000)**

NOW has, for illustrative purposes, accounted for the reduction in OM&A and OPEB costs across several OM&A categories. The Parties understand and agree that NOW has the discretion and responsibility to manage the proposed reduction as it sees fit during the test year.

The following provides further detail on the OPEB adjustment. In its application, NOW Inc. included OPEBs of $35,219 representing the accrual method of accounting for OPEBs. The Parties have agreed that NOW Inc. will instead include OPEBs calculated on a cash basis in the amount of $26,510 in OM&A. The difference of $8,709 will be recorded in a new deferral account. While the normal course of changing the treatment of OPEBs from an accrual to cash basis would result in reductions to both OM&A and Rate Base as a result of the capitalization of a portion of the OPEB expense, the amount of OPEB expense that is embedded in NOW Inc.'s Rate Base that would need to be removed is immaterial from a rate perspective. The required adjustment to Rate Base is in the order of $500, and the Revenue Requirement impact of that amount is inconsequential from a regulatory perspective (changing rate base by $500 has no rate impact to 4 decimal places). Accordingly, the Parties have agreed to reflect the full adjustment to OPEBs as a result of reflecting those costs on a cash rather than accrual basis as a reduction to OM&A for rate setting purposes. Similarly the full OPEB adjustment will be tracked in the requested deferral account as an OM&A expense, such that if the Board allows NOW Inc. to collect OPEB expense on an accrual basis the full OPEB amount tracked will be recoverable by NOW Inc. as an OM&A expense.

The Parties acknowledge that the OEB is currently reviewing its policy for the Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs (Board File No. EB-2015-0040). The deferral account is to record the difference in revenue requirement for each year, starting in the test year for OPEBs accounted for using a forecasted cash basis and OPEBs accounted for using a forecasted accrual basis. NOW Inc. will book differences between the test year forecasted cash and test year forecasted accrual OPEBs to the account (Account 1508- Other Regulatory Assets, Sub-account – OPEB Forecast Cash vs. Forecast Accrual Differential Deferral Account) each year until its next Cost of Service rate application. NOW Inc. will only seek to dispose of the balance in this account at its next Cost of Service rate application if the OEB determines LDCs may recover OPEBs in rates using a forecasted accrual accounting methodology. Attachment 5 to this Settlement Proposal is a Draft Accounting Order for the proposed OPEB Deferral Account.

Evidence References

- Exhibit 1/Tab2/Schedule 1 – Executive Summary
- Exhibit 1/Tab 5/Schedule 5 – OM&A Expense
- Exhibit 4 – Operating Costs

IR Responses

- 4-Staff-35 to 4-Staff-45
- 4-SEC-22 to 4-SEC-31
- 4-VECC-29 to 4-VECC-41
- 4-AMPCO-24 to 4-AMPCO-37

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

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?

Full Settlement

The Parties agree that the methodology used by NOW to calculate the Revenue Requirement is appropriate.

A summary of the adjusted Revenue Requirement reflecting adjustments and settled issues in accordance with the above is presented in Table 5 below.

Table 5: Revenue Requirement

Description		Application (A)	IR/TC Responses(B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Cost of Capital	Regulated Return on Capital	468,569	441,435	(27,134)	440,384	(1,051)
	Regulated Rate of Return	6.03%	5.67%	-0.36%	5.67%	0.00%
Rate Base & Capital Expenditures	Rate Base	7,766,288	7,786,168	19,880	7,767,615	(18,553)
	Working Capital	18,892,797	19,613,740	720,943	19,695,996	82,256
	Working Capital Allowance	1,416,960	1,471,030	54,071	1,477,200	6,169
Operating Expenses	Amortization/Depreciation	439,680	439,433	(247)	438,877	(556)
	Grossed Up Income Taxes	16,330	42,771	26,441	42,910	139
	OM&A	2,907,906	2,907,906	0	2,757,906	(150,000)
Revenue Requirement	Service Revenue Requirement	3,832,485	3,831,545	(940)	3,680,077	(151,468)
	Other Revenues	268,918	268,918	0	268,918	0
	Base Revenue Requirement	3,563,567	3,562,627	(940)	3,411,159	(151,468)
	Grossed Up Revenue Deficiency/(Sufficiency)	619,988	582,114	(37,874)	390,087	(192,027)

An updated Revenue Requirement Work Form Model has been filed though the OEB's e-filing service, and a copy is included in Attachment 1 of this Agreement.

Evidence References

- Exhibit 1/Tab 5/Schedule 1 – Revenue Requirement
- Exhibit 3/Tab 3/Schedule 1 – Other Revenue
- Exhibit 6/Tab 1/Schedule 1 – Revenue Sufficiency or Deficiency
- Revenue Requirement Workform Model

IR Responses

- 3-Staff-34
- 3-VECC-28
- 6-Staff-48
- 6-SEC-33
- Updated Revenue Requirement Workform Model

Supporting Parties
NOW, VECC, SEC, AMPCO

Parties Taking No Position

2.1.1 Cost of Capital

Full Settlement

The Parties agree to NOW's proposed cost of capital parameters as updated to reflect the OEB's deemed cost of capital parameters for the 2017 test year as per the OEB letter of October 27, 2016 (reference IR 5-Staff-46).

Table 6: Debt Instruments

Appendix 2-OB
Debt Instruments

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

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Loan 8	Caisse Populaire	Third-Party	Fixed Rate	27-Jul-12	20	$ 3,680,980	3.75%	$ 79,796.59	Due in 2017, interest pro-rated (211/365)
2	Loan 1	Caisse Populaire	Third-Party	Fixed Rate	19-Sep-13	5	$ 158,459	3.75%	$ 5,942.21	
3	Loan 4	Caisse Populaire	Third-Party	Fixed Rate	28-Apr-14	5	$ 127,978	3.42%	$ 4,376.85	
4	Loan 8-B	Caisse Populaire	Third-Party	Fixed Rate	31-Jul-17	20	$ 3,680,980	3.72%	$ 57,774.24	Renewed in 2017, interest pro-rated (154/365)
5		Caisse Populaire	Third-Party	Fixed Rate	1-Jan-17	5	$ 382,447	3.72%	$ 14,227.04	
Total							$ 4,349,864	3.73%	$ 162,116.93	

Notes

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with any
3 Add more lines above row 12 if necessary.

Table 7 below details the cost of capital calculation.

Table 7: Cost of Capital Calculation

Per Initial Application
Appendix 2-OA
Capital Structure and Cost of Capital

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

Year: 2017

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$4,349,121	4.09%	$177,954
2	Short-term Debt	4.00%	(1)	$310,652	1.65%	$5,126
3	**Total Debt**	60.0%		$4,659,773	3.93%	$183,080
	Equity					
4	Common Equity	40.00%		$3,106,515	9.19%	$285,489
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$3,106,515	9.19%	$285,489
7	**Total**	100.0%		$7,766,288	6.03%	$468,569

Per Settlement Agreement

Appendix 2-OA
Capital Structure and Cost of Capital

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

Year: 2017

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$4,349,864	3.73%	$162,117
2	Short-term Debt	4.00%	(1)	$310,705	1.76%	$5,468
3	**Total Debt**	60.0%		$4,660,569	3.60%	$167,585
	Equity					
4	Common Equity	40.00%		$3,107,046	8.78%	$272,799
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$3,107,046	8.78%	$272,799
7	**Total**	100.0%		$7,767,615	5.67%	$440,384

Notes

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

Evidence References

- Exhibit 1/Tab 2/Schedule 1 – Executive Summary
- Exhibit 1/Tab 5/Schedule 6
- Exhibit 5/Tab 1/Schedule 1 – Cost of Capital and Capital Structure

IR Responses

- 5-Staff-46
- 5-Staff-47
- 5-VECC-42

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

2.1.2 Rate Base

Full Settlement

The Parties accept the evidence of NOW that the Rate Base calculations, after making adjustments related to other settled items, are reasonable and have been appropriately determined in accordance with OEB policies and practices.

Table 8 below outlines NOW's Rate Base calculation.

Table 8: Rate Base

Description	Application (A)	IR/TC Responses(B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Gross Fixed Assets (Average)	8,496,799	8,463,079	(33,720)	8,438,079	(25,000)
Accumulated Depreciation (Average)	(2,147,470)	(2,147,941)	(471)	(2,147,663)	278
Net Fixed Assets (Average)	6,349,329	6,315,137	(34,191)	6,290,415	(24,722)
Working Capital Base	18,892,797	19,613,740	720,943	19,695,996	82,256
Working Capital Allowance (%)	7.50%	7.50%	0	7.5%	0.00%
Allowance for Working Capital	1,416,960	1,471,030	54,071	1,477,200	6,169
Total Rate Base	**7,766,288**	**7,786,168**	**19,879**	**7,767,615**	**(18,553)**

Evidence References

- Exhibit 1/Tab 5/Schedule 4 – Rate Base and DSP
- Exhibit 2 - Rate Base

IR Responses

- 2-Staff-7
- 2-Staff-10 to 2-Staff-27
- 2-SEC-13 to 2-SEC-18
- 2-VECC- 4 to 2-VECC-13; 2-VECC-16 to 2-VECC-18
- 2-AMPCO-2 to 2-AMPCO-4; 2-AMPCO-12-22

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

2.1.3 Working Capital Allowance

Full Settlement

The Parties agree that NOW's calculation of its Working Capital Allowance is appropriate. Set out in Table 9 is the Working Capital Allowance calculation, as updated to reflect other elements of the settlement.

Table 9: Working Capital Allowance Calculation

Description	Application (A)	IR/TC Responses(B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Operations	815,665	815,665	0	761,627	(54,038)
Maintenance	697,590	697,590	0	621,628	(75,962)
Billing and Collecting	746,564	746,564	0	726,564	(20,000)
Community Relations	0	0	0	0	0
Administrative and General	648,087	648,087	0	648,087	0
Total	**2,907,906**	**2,907,906**	**0**	**2,757,906**	**(150,000)**
Cost of Power	**15,984,891**	**16,705,834**	720,943	**16,938,090**	232,256
Working Capital Base	**18,892,797**	**19,613,740**	720,943	**19,695,996**	82,256
Working Capital Allowance (%)	7.50%	7.50%	0	7.50%	0.00%
Working Capital Allowance ($)	**1,416,960**	**1,471,030**	**54,071**	**1,477,200**	**6,169**

Evidence References

- Exhibit 1/Tab 5/Schedule 4 – Rate Base and DSP
- Exhibit 2/Tab 1/ Schedule 4 – Allowance for Working Capital

IR Responses

- 2-Staff-8

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

2.1.4 Depreciation

Full Settlement

The Parties accept that the updated forecast of depreciation/amortization expenses is appropriate.

Table 10: Depreciation

Description	Application (A)	IR/TC Responses(B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Depreciation	439,680	439,433	(247)	438,877	(556)

Evidence References

- Exhibit 2/Tab 1/ Schedule 3 – Depreciation Expense
- Exhibit 4/Tab 4/ Schedule 1 – Depreciation Policy
- Chapter 2 Appendix 2-BA

IR Responses

- 2-Staff-7
- 4-Staff-43
- 4-SEC-22
- 4-SEC-31
- 4-VECC-29

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

2.1.5 Taxes

Full Settlement

The Parties accept the evidence of NOW that its forecast taxes, as adjusted, are appropriate and have been correctly determined in accordance with OEB accounting policies and practices. It is noted that during the settlement discussions it was identified that the forecast 2016 tax loss as calculated in the initial application was incorrect as it double counted the depreciation expense associated with Transportation Equipment and Stores Equipment. The actual 2016 taxes as filed on February 17, 2017 correctly reflect 2016 depreciation expense.

A summary of the updated Taxes is presented in Table 11 below.

Table 11: Income Taxes

Description	Application (A)	IR/TC Responses(B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Grossed-Up Income Taxes	16,330	42,771	26,441	42,910	139

An updated Tax Model has been submitted in Live Excel format as part of this Settlement Proposal.

Evidence References

- Exhibit 4/Tab5/Schedule 1 – Overview of Provision in Lieu of Taxes (PILS)
- Exhibit 4/Tab5/Schedule 2 – Historical PILS

IR Responses

- 4-Staff-44

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

2.1.6 Other Revenue

Full Settlement

The Parties accept the evidence of NOW that its proposed Other Revenues are appropriate and have been correctly determined in accordance with OEB accounting policies and practices.

Table 12: Other Revenue

Description	Application (A)	IR/TC Responses(B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Specific Service Charges	30,045	30,045	0	30,045	0
Late Payment Charges	89,347	89,347	0	89,347	0
Other Distribution Revenue	119,246	119,246	0	119,246	0
Other Income and Deductions	30,280	30,280	0	30,280	0
Total Revenue Offsets	**268,918**	**268,918**	**0**	**268,918**	**0**

Evidence References

- Exhibit 3/Tab3/Schedule 1 – Other Revenue

IR Responses

- 3-Staff-34
- 3-VECC-28

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

2.2 Has the revenue requirement been accurately determined based on these elements?

Full Settlement

The Parties accept the evidence of NOW that all the elements of the Revenue Requirement has been determined accurately. Specific adjustments to the Revenue Requirement as a result of the IR responses and the Settlement Proposal are summarized below.

Table 13: Summary of Changes

	Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
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	$ 468,569	6.03%	$ 7,766,288	$ 18,892,797	$ 1,416,960	$ 439,680	$ 16,330	$ 2,907,906	$ 3,832,485	$ 268,918	$ 3,563,567	$ 619,988
Supplimental IRs	$ 441,435	5.67%	$ 7,786,168	$ 19,613,740	$ 1,471,031	$ 439,433	$ 42,771	$ 2,907,906	$ 3,831,545	$ 268,918	$ 3,562,627	$ 582,114
Change	-$ 27,134	-0.36%	$ 19,880	$ 720,943	$ 54,071	-$ 247	$ 26,441	$ -	-$ 940	$ -	-$ 940	-$ 37,874
GS < 50 Load Forecast correction	$ 441,446	5.67%	$ 7,786,358	$ 19,616,270	$ 1,471,220	$ 439,433	$ 42,772	$ 2,907,906	$ 3,831,557	$ 268,918	$ 3,562,639	$ 581,774
Change	$ 11	0.00%	$ 190	$ 2,530	$ 190	$ -	$ 1	$ -	$ 12	$ -	$ 12	-$ 340
Capital Expenditure Reduction	$ 440,045	5.67%	$ 7,761,636	$ 19,616,270	$ 1,471,220	$ 438,877	$ 42,873	$ 2,907,906	$ 3,829,701	$ 268,918	$ 3,560,783	$ 579,472
Change	-$ 1,401	0.00%	-$ 24,722	$ -	$ -	-$ 556	$ 101	$ -	-$ 1,856	$ -	-$ 1,856	-$ 2,302
Residential Load Forecast increase by 920,000kWh	$ 440,570	5.67%	$ 7,770,893	$ 19,739,698	$ 1,480,477	$ 438,877	$ 42,931	$ 2,907,906	$ 3,830,283	$ 268,918	$ 3,561,365	$ 566,776
Change	$ 524	0.00%	$ 9,257	$ 123,428	$ 9,257	$ -	$ 58	$ -	$ 582	$ -	$ 582	-$ 12,696
OM&A Reduction of $150,000	$ 439,932	5.67%	$ 7,759,643	$ 19,589,698	$ 1,469,227	$ 438,877	$ 42,861	$ 2,757,906	$ 3,679,576	$ 268,918	$ 3,410,658	$ 389,556
Change	-$ 637	0.00%	-$ 11,250	-$ 150,000	-$ 11,250	$ -	-$ 69	-$ 150,000	-$ 150,707	$ -	-$ 150,707	-$ 177,220
Updated RRRP Rate	$ 440,384	5.67%	$ 7,767,615	$ 19,695,996	$ 1,477,200	$ 438,877	$ 42,910	$ 2,757,906	$ 3,680,077	$ 268,918	$ 3,411,159	$ 390,087
Change	$ 452	0.00%	$ 7,972	$ 106,298	$ 7,972	$ -	$ 49	$ -	$ 501	$ -	$ 501	$ 531

Evidence References

- Exhibit 1/Tab 5/Schedule 1 – Revenue Requirement
- Exhibit 3/Tab 3/Schedule 1 – Other Revenue
- Exhibit 6/Tab 1/Schedule 1 – Revenue Deficiency or Sufficiency
- Revenue Requirement Workform Model

IR Responses

- 6-Staff-48
- 6-SEC-33
- Updated Revenue Requirement Workform Model

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

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 Northern Ontario Wires Inc.'s customers?

Full Settlement

The Parties accept the evidence of NOW and its methodology used for the load forecast, customer forecast, loss factors and Conservation and Demand Management ("CDM") adjustments after incorporating the following:

- An addition of 920,000 kWh's Residential to reflect that the trend of historical 2006 – 2015 CDM is already included in the underlying forecast amount such that a further manual CDM adjustment is unnecessary.

The resulting billing determinants are presented in Table 14 below.

Table 14: 2017 Test Year Billing Determinants (for Cost Allocation and Rate Design)

Rate Class	Application (A)		IR/TC Responses(B)		Variance (C) = (B) - (A)		Settlement (D)		Variance (E) = (D) - (B)	
	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Residential	40,704,801	0	40,704,801	0	0	0	41,624,801	0	920,000	0
GS<50	19,740,824	0	19,759,776	0	18,952	0	19,759,776	0	0	0
GS>50	56,387,438	166,531	62,140,492	181,679	5,753,054	15,148	62,140,492	181,679	0	0
Street Light	556,610	1,576	556,610	1,576	0	0	556,610	1,576	0	0
USL	165,218	0	165,218	0	0	0	165,218	0	0	0
Total	**117,554,891**	**168,107**	**123,326,896**	**183,255**	**5,772,005**	**15,148**	**124,246,896**	**183,255**	**920,000**	**0**

An updated copy of NOW's Load Forecast Model has been submitted in Live Excel format as part of this Settlement Proposal.

Evidence References

- Exhibit 1/Tab 5/Schedule 3 – Load Forecast Summary
- Exhibit 3/Tab 1/Schedule 2 – Historical and Forecast Volumes (Load Forecast Report)
- Exhibit 3/Tab 1/Schedule 3 – CDM Adjustment
- Exhibit 3/Tab 2/Schedule 1 – Variance Analysis of Load Forecast
- Load Forecast Model

IR Responses

- 2-Staff-25
- 3-Staff-28 to 3-Staff-32
- 3-VECC-19 to 3-VECC-26

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

3.1.1 Customer/Connection Forecast

Full Settlement

The Parties agree that NOW's forecast of customers/connections is appropriate.

Table 15: Summary of Load Forecast Customer Counts/Connections

Rate Class	Application (A)	IR/TC Responses(B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Residential	5,216	5,216	0	5,216	0
GS<50	784	784	0	784	0
GS>50	71	71	0	71	0
Street Light	1,650	1,650		1,650	0
USL	23	23		23	0
Total	**7,744**	**7,744**	**0**	**7,744**	**0**

Evidence References

- Exhibit 1/Tab 5/Schedule 3 – Load Forecast Summary
- Exhibit 3/Tab 1/Schedule 2 – Historical and Forecast Volumes (Load Forecast Report)
- Load Forecast Model

IR Responses

- 3-Staff-29
- 3-VECC-49

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

3.1.2 Load Forecast

Full Settlement

The Parties have agreed to the following update in the Load Forecast Model:

- An addition of 5,753,054 kWh and 15,158 kW to the GS>50 load to reflect the full year ongoing impact of a new customer. Reference IR 3-Staff-32.
- An addition of 920,000 kWh Residential to reflect that the trend of historical 2006 – 2015 CDM is already included in the underlying forecast amount such that an additional manual CDM adjustment is unnecessary.

This impact of the above change results in a volumetric increase to the residential customer class, thereby reducing the calculated residential rate.

Table 16 below provides the weather normalized billed kWh and billed demand forecast by rate class. The billed demand forecast for the 2017 Test Year is based on an average ratio of kW to kWh for the classes that are billed distribution on a demand basis.

Table 16: Summary of Load Forecast Billed kWh (CDM Adjusted)

Rate Class	Application (A)		IR/TC Responses(B)		Variance (C) = (B) - (A)		Settlement (D)		Variance (E) = (D) - (B)	
	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Residential	40,704,801	0	40,704,801	0	0	0	41,624,801	0	920,000	0
GS<50	19,740,824	0	19,759,776	0	18,952	0	19,759,776	0	0	0
GS>50	56,387,438	166,531	62,140,492	181,679	5,753,054	15,148	62,140,492	181,679	0	0
Street Light	556,610	1,576	556,610	1,576	0	0	556,610	1,576	0	0
USL	165,218	0	165,218	0	0	0	165,218	0	0	0
Total	**117,554,891**	**168,107**	**123,326,896**	**183,255**	**5,772,005**	**15,148**	**124,246,896**	**183,255**	**920,000**	**0**

Table 17: 2017 Test Year CDM Adjustment

Rate Class	Application (A)		IR/TC Responses(B)		Variance (C) = (B) - (A)		Settlement (D)		Variance (E) = (D) - (B)	
	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Residential	362,099	0	362,099	0	0	0	362,099	0	0	0
GS<50	272,352	0	253,401	0	(18,951)	0	253,401	0	0	0
GS>50	777,944	2,298	796,895	2,330	18,951	32	796,895	2,330	0	0
Street Light	0	0	0	0	0	0	0	0	0	0
USL	0	0	0	0	0	0	0	0	0	0
Total	**1,412,395**	**2,298**	**1,412,395**	**2,330**	**0**	**32**	**1,412,395**	**2,330**	**0**	**0**

Evidence References

- Exhibit 1/Tab 5/Schedule 3 – Load Forecast Summary
- Exhibit 3/Tab 1/Schedule 2 – Historical and Forecast Volumes (Load Forecast Report)
- Load Forecast Model

IR Responses

- 3 Staff-28 to 3-Staff-32
- 3-SEC-20 to 3-SEC21
- 3-VECC-19 to 3-VECC-27

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

3.1.3 Loss Factors

Full Settlement

The Parties have agreed to the Loss Factors as calculated Appendix 2-R and summarized in Table 18 below:

Table 18: Loss Factors

Description	2017 Proposed
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0694
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0694
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0694
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0694

Evidence References

- Exhibit 3/Tab 1/Schedule 2 – Historical and Forecast Volumes (Load Forecast Report)
- Exhibit 8/Tab 4/Schedule 1 – Loss Adjustment Factors

IR Responses

- No IRs on this issue

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

3.1.4 LRAMVA Baseline

Full Settlement

Based on the savings from the 2015, 2016 and 2017 programs, the Parties have agreed to the LRAMVA thresholds as set out in Table 19 below.

Table 19: 2017 LRAMVA Baseline kWhs and kWs

Rate Class	LRAMVA Baseline kWh	LRAMVA Baseline kW
Residential	541,840	0
GS<50	367,424	0
GS>50	1,155,473	3,378
Street Light	0	0
USL	0	0
Total	**2,064,737**	**3,378**

Evidence References

- Exhibit 1/Tab 5/Schedule 3 – Load Forecast Summary
- Exhibit 4/Tab 6/Schedule 1 – Lost Revenue Adjustment Mechanism
- Exhibit 3/Tab 1/Schedule 2 – Historical and Forecast Volumes (Load Forecast Report)
- Load Forecast Model

IR Responses

- No IRs on this issue.

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

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

Full Settlement

The Parties have agreed to move all R/C ratios to within the Board's acceptable ranges in the test year, as set out in Table 20.

Table 20: Summary of 2017 Revenue to Cost Ratios

Rate Class	Application (A)	IR/TC Responses(B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Residential	96.92%	97.11%	0.19%	96.91%	(0.20%)
GS<50	115.70%	116.42%	0.72%	116.12%	(0.30%)
GS>50	104.91%	102.20%	(2.71%)	104.54%	2.34%
Street Light	120.00%	120.00%	0.00%	120.00%	0.00%
USL	83.35%	83.27%	(0.08%)	83.09%	(0.18%)

The Parties accept the evidence of NOW 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.

Evidence References

- Exhibit 1/Tab 5/Schedule 7 – Cost Allocation and Rate Design
- Exhibit 7
- Cost Allocation Model

IR Responses

- 7-Staff-49 to 7-Staff-51
- 7-VECC-44 to 7-VECC-45

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

3.3 Are Northern Ontario Wires Inc.'s proposals, including the proposed fixed/variable splits, for rate design appropriate?

Full Settlement

The Parties accept the evidence of NOW that all elements of the rate design have been correctly determined in accordance with OEB policies and practices.

Table 21: May 1, 2017 Distribution Rates

Rate Class	Fixed Rate	Billing Determinant	Variable Rate	Fixed %	Variable %
Residential	$ 30.30	kWh	$ 0.0092	83.18%	16.82%
GS<50	$ 31.76	kWh	$ 0.0177	46.00%	54.00%
GS>50	$ 191.60	kW	$ 1.1043	52.87%	47.13%
Street Light	$ 7.64	kW	$ 9.0038	91.42%	8.58%
USL	$ 16.10	kWh	$ 0.0176	60.45%	39.55%

Evidence References

- Exhibit 1/Tab 5/ Schedule 7 – Cost Allocation and Rate Design
- Exhibit 8
- Revenue Requirement Workform Model

IR Responses

- 8-Staff-52 to 8-Staff-56
- 8-VECC-46 to 8-VECC-47

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

3.3.1 Residential Rate Design

Full Settlement

The Parties accept that NOW's proposal to move to a fully fixed monthly charge by 2019 is in accordance with OEB policies.

Evidence References

- Exhibit 1/Tab 5/Schedule 7 – Cost Allocation and Rate Design
- Exhibit 8/Tab 2/Schedule 1 – Rate Design Policy
- Rate Design Model

IR Responses

- No IRs on this issue.

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

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

Full Settlement

The Parties accept the evidence of NOW that all elements of the Retail Transmission Service Rates and Low Voltage rates have been correctly determined in accordance with OEB policies and practices.

Evidence References

- Exhibit 8/Tab 3/Schedule 1
- RTSR Workform
- RTSR Model

IR Responses

- No IRs on this issue.

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

3.4.1 Retail Transmission Service Rates

Full Settlement

The Parties have agreed to the RTSR rates presented in Table 22 below. An updated copy of the OEB's RTSR model incorporating the new load forecast has been submitted in live Excel format as part of this settlement proposal.

Table 22: Updated RTSR Network and Connection Rates

Rate Class	Billing Determinant	Proposed Network	Proposed Connection
Residential	kWh	$ 0.0062	$ 0.0028
GS<50	kWh	$ 0.0059	$ 0.0027
GS>50	kW	$ 2.3529	$ 1.0401
Street Light	kW	$ 1.7746	$ 0.8040
USL	kWh	$ 0.0059	$ 0.0027

Evidence References

- Exhibit 8/Tab 3/Schedule 1
- RTSR Workform

IR Responses

- No IRs on this issue.

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

3.4.2 Low Voltage Rates

Full Settlement

The Parties have agreed to the Low Voltage rates presented in Table 23 below.

Table 23: Updated Low Voltage Rates

Rate Class	Billing Determinant	Proposed LV Rate
Residential	kWh	$ 0.0016
GS<50	kWh	$ 0.0015
GS>50	kW	$ 0.5377
Street Light	kW	$ 0.4152
USL	kWh	$ 0.0015

Evidence References

- Exhibit 8/Tab 3/Schedule 5

IR Responses

- 8-Staff-54
- 4-VECC-46

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

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?

Full Settlement

The Parties accept the evidence of NOW 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.

An updated EDDVAR Continuity Schedule is provided in working Excel format reflecting this Settlement Proposal and includes the calculation of the various riders discussed above.

Evidence References

- Exhibit 1/Tab 3/Schedule 11 – Statement of Changes in Methodology
- Exhibit 1/Tab 5/Schedule 2 – Budgeting and Accounting Assumptions

IR Responses

- 1-SEC-5
- 1-SEC-7

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

4.2 Are Northern Ontario Wires Inc.'s proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts and the continuation of existing accounts, appropriate?

Full Settlement

With the exceptions detailed below, the Parties accept the evidence of NOW that all elements of the applied for deferral and variance accounts are appropriate, including the balances in the existing accounts and their disposition commencing May 1, 2017:

- The Parties have agreed to establish a deferral and variance account to record the impact of including in revenue requirement NOW's OPEB costs on cash basis rather than on an accrual basis pending the Board's decision in EB-2015-0040;
- The Parties have agreed to due to the relative small balance remaining in the IFRS Transition Deferral Account ($11,000), it will be cleared and then closed, without the need to wait for the amount to be audited, with interest on the account to be calculated to April 30, 2017;
- The Parties have agreed to a correction to the LRAMVA amount to be cleared to the streetlighting and USL customers in the amount of $413.

An updated summary of deferral and variance accounts for disposition is as follows:

Table 24: Summary of Deferral and Variance Accounts for Disposition

Deferral and Variance Accounts	Account Number	2015 Closing Principal Balance (Adjusted for 2016 Disposition)	2015 Closing Interest Balance (Adjusted for 2016 Disposition)	Projected Interest (Jan 1, 2016 - April 30, 2017)	Total Claim
Group 1					
LV Variance Account	1550	$45,390	-$105	$898	$46,183
SME Charge Variance Account	1551	$183	-$1	$3	$185
RSVA - WMS Charge	1580	-$265,286	-$116	-$3,920	-$269,322
Variance WMS – Sub-account CBR Class B	1580	$32,151	$101	$472	$32,725
RSVA - Retail Transmission Network Charge	1584	$135,650	-$421	$2,759	$137,988
RSVA - Retail Transmission Connection Charge	1586	$65,680	-$119	$1,250	$66,810
RSVA - Power (excluding Global Adjustment)	1588	-$270,573	-$97	-$2,907	-$273,577
Disposition of Regulatory Balances (2013)	1595	$17	-$0	$0	$17
Disposition of Regulatory Balances (2015)	1595	-$87,376	-$808	$0	$0
Total Group 1 (excluding Global Adjustment)		**-$344,165**	**-$1,564**	**-$1,445**	**-$258,991**
RSVA - Global Adjustment	**1589**	**$26,756**	**-$985**	**$721**	**$26,492**
Group 2					
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$55,529	$2,134	$764	$58,426
Other Regulatory Assets - Sub-Account - Other	1508	$0	$18	$0	$18
RCVA - Retail	1518	-$8,750	-$525	-$128	-$9,403
Misc. Deferred Debits	1525	$0	-$460	$0	-$460
RCVA - STR	1548	$6,662	$238	$97	$6,997
Special Purpose Charge Assessment Variance Account	1521	$3,972	$901	$58	$4,931
Total Group 2		**$57,413**	**$2,305**	**$791**	**$60,509**
Other Accounts					
Renewable Generation Connection OM&A Deferral Account9	1532	-$2,100	-$103	-$31	-$2,234
Smart Meter Capital and Recovery Offset Variance - Stranded Meter Costs	1555	$25,085	$2,461	$0	$27,546
LRAM Variance Account	1568	$29,403	$0	$0	$29,403
Total Other Accounts		**$52,388**	**$2,357**	**-$31**	**$54,715**
Total Deferral and Variance Balance		**-$207,608**	**$2,113**	**$36**	**-$117,274**

The Parties have also agreed to the continuation of existing accounts, other than the aforementioned IFRS Transition Deferral Account.

The rate riders have been updated to reflect the settlement proposal of the customer and load forecast.

Table 25 below summarizes the updated amounts for disposition and associated rate riders by rate class.

Table 25: Updated DVA and LRAMVA Rate Riders

Rate Class	Billing Determinant	Disposition of DVA's (2017)		
		$/kWh	$/kW	$/month/customer
Residential	kWh	-$ 0.0011		$ 0.16
GS<50	kWh	-$ 0.0009		
GS>50	kW		-$ 0.2765	
Street Light	kW		-$ 0.2856	
USL	kWh	-$ 0.0009		

Rate Class	Billing Determinant	Disposition of LRAMVA	
		$/kWh	$/kW
Residential	kWh	-$ 0.0001	
GS<50	kWh	$ 0.0009	
GS>50	kW		-$ 0.0013
Street Light	kW		-$ 0.1207
USL	kWh	-$ 0.0002	

Evidence References

- Exhibit 1/Tab 5/Schedule 8 – Deferral and Variance Accounts
- Exhibit 9

IR Responses

- 9-Staff-57
- 9-VECC-48
- 3-VECC-50

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

4.2.1 Effective Date

Full Settlement

The Parties have agreed that NOW's new rates should be made effective May 1, 2017. In the event there is a delay to the implementation of new rates on May 1, 2017 the Parties agree that existing rates should be made interim as of May 1, 2017 and that a deferral account be established to track the foregone revenue that accrues as a result of the late implementation date.

Evidence References

- Exhibit 1/Tab 3/Schedule 9

IR Responses

- No IRs on this issue.

Supporting Parties

NOW, VECC, SEC, AMPCO

Parties Taking No Position

5 ATTACHMENTS

1. Revenue Requirement Workform
2. Proposed Tariff Sheet
3. Bill Impacts
4. 2016 and 2017 Fixed Asset Continuity Schedule
5. Accounting Order – OPEB

Attachment 1

Revenue Requirement Workform (RRWF) for 2017 Filers

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$2,907,906		$2,757,906		$2,757,906	
2	Amortization/Depreciation	$439,680		$438,877		$438,877	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$16,330		$42,910		$42,910	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$183,080		$167,585		$167,585	
	Return on Deemed Equity	$285,489		$272,799		$272,799	
8	**Service Revenue Requirement (before Revenues)**	$3,832,485		$3,680,077		$3,680,077	
9	Revenue Offsets	$268,918		$268,918		$268,918	
10	**Base Revenue Requirement** **(excluding Tranformer Owership Allowance credit adjustment)**	$3,563,567		$3,411,159		$3,411,159	
11	Distribution revenue	$3,563,567		$3,411,159		$3,411,159	
12	Other revenue	$268,918		$268,918		$268,918	
13	**Total revenue**	$3,832,485		$3,680,077		$3,680,077	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	($0)	(1)	($0)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Settlement Agreement	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$3,832,485	$3,680,077	($0)	$3,680,077	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$619,988	$390,087	($0)	$390,087	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$3,563,567	$3,411,159	($0)	$3,411,159	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$543,320	$374,484	($0)	$374,484	($1)

Attachment 2

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the utility'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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	30.30
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0092
Low Voltage Service Rate	$/kWh	0.0016
Retail Transmission Rate - Network Service Rate	$/kWh	0.0062
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0028
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2019	$/kWh	-0.0011
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 Accounts (2017) - effective until April 30, 2019	$	0.16
Rate Rider for Disposition of LRAMVA - effective until April 30, 2019	$/kWh	-0.0001

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS

In addition to the charges specified on page 1 of this tariff of rates and charges, the following credits are to be applied to eligible residential customers.

APPLICATION

The application of the charges are in accordance with the Distribution System Code (Section 9) and subsection 79.2(4) of the Ontario Energy Board Act, 1998.
The application of these charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.
In this class:

"Aboriginal person" includes a person who is a First Nations person, a Métis person or an Inuit person;
"account-holder" means a consumer who has an account with a distributor that falls within a residential-rate classification as specified in a rate order made by the Ontario Energy Board under section 78 of the Act, and who lives at the service address to which the account relates for at least six months in a year;
"electricity-intensive medical device" means an oxygen concentrator, a mechanical ventilator, or such other device as may be specified by the Ontario Energy Board;
"household" means the account-holder and any other people living at the accountholder's service address for at least six months in a year, including people other than the account-holder's spouse, children or other relatives;
"household income" means the combined annual after-tax income of all members of a household aged 16 or over;

MONTHLY RATES AND CHARGES

Class A
(a) account-holders with a household income of $28,000 or less living in a household of one or two persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of three persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of five persons; and
(d) account-holders with a household income of between $48,001 and $52,000 living in a household of seven or more persons;
but does not include account-holders in Class E.

OESP Credit	$	(30.00)

Class B
(a) account-holders with a household income of $28,000 or less living in a household of three persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of four persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of six persons;
but does not include account-holders in Class F.

OESP Credit	$	(34.00)

Class C
(a) account-holders with a household income of $28,000 or less living in a household of four persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of five persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of seven or more persons;
but does not include account-holders in Class G.

OESP Credit	$	(38.00)

Class D
(a) account-holders with a household income of $28,000 or less living in a household of five persons; and
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of six persons;
but does not include account-holders in Class H.

OESP Credit	$	(42.00)

Class E
Class E comprises account-holders with a household income and household size described under Class A who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(45.00)

Class F
(a) account-holders with a household income of $28,000 or less living in a household of six or more persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of seven or more persons; or
(c) account-holders with a household income and household size described under Class B who also meet any of the following conditions:

i. the dwelling to which the account relates is heated primarily by electricity;
ii. the account-holder or any member of the account-holder's household is an Aboriginal person; or
iii. the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates

OESP Credit	$	(50.00)

ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS (Cont'd)

Class G

Class G comprises account-holders with a household income and household size described under Class C who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder’s household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder’s household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(55.00)

Class H

Class H comprises account-holders with a household income and household size described under Class D who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder’s household is an Aboriginal person ; or
(c) the account-holder or any member of the account-holder’s household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(60.00)

Class I

Class I comprises account-holders with a household income and household size described under paragraphs (a) or (b) of Class F who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder’s household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder’s household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(75.00)

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the utility'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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.76
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0177
Low Voltage Service Rate	$/kWh	0.0015
Retail Transmission Rate - Network Service Rate	$/kWh	0.0059
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0027
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2019	$/kWh	-0.0011
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 Accounts (2017) - effective until April 30, 2019	$/kWh	0.0002
Rate Rider for Disposition of LRAMVA - effective until April 30, 2019	$/kWh	0.0009

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the utility'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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	191.60
Distribution Volumetric Rate	$/kW	1.1043
Low Voltage Service Rate	$/kW	0.5377
Retail Transmission Rate - Network Service Rate	$/kW	2.3529
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.0401
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2019	$/kW	-0.3567
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 Accounts (2017) - effective until April 30, 2019	$/kW	0.0802
Rate Rider for Disposition of LRAMVA - effective until April 30, 2019	$/kW	-0.0013

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the utility'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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	16.10
Distribution Volumetric Rate	$/kWh	0.0176
Low Voltage Service Rate	$/kWh	0.0015
Retail Transmission Rate - Network Service Rate	$/kWh	0.0059
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0027
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2019	$/kWh	-0.0011
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 Accounts (2017) - effective until April 30, 2019	$/kWh	0.0002
Rate Rider for Disposition of LRAMVA - effective until April 30, 2019	$/kWh	-0.0002

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Further servicing details are available in the utility'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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	7.64
Distribution Volumetric Rate	$/kW	9.0038
Low Voltage Service Rate	$/kW	0.4152
Retail Transmission Rate - Network Service Rate	$/kW	1.7746
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.8040
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until April 30, 2019	$/kW	-0.3684
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts - Group 2 Accounts (2017) - effective until April 30, 2019	$/kW	0.0828
Rate Rider for Disposition of LRAMVA - effective until April 30, 2019	$/kW	-0.1207

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0021
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the utility'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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.6000)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Returned cheque (plus bank charges)	$	15.00
Statement of account	$	15.00
Account history	$	15.00
Request for other billing information	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/reconnect at meter - during regular hours	$	65.00
Disconnect/reconnect at meter - after regular hours	$	185.00

Other

Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	22.35

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board, and amendments thereto as approved by the Ontario Energy 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 Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

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

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

LOSS FACTORS

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

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0694
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0587

Attachment 3

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	750	kWh
Demand	-	kW
Current Loss Factor	1.0713	
Proposed/Approved Loss Factor	1.0694	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 24.25	1	$ 24.25	$ 30.30	1	$ 30.30	$ 6.05	24.95%
Distribution Volumetric Rate	$ 0.0123	750	$ 9.23	$ 0.0092	750	$ 6.90	$ (2.33)	-25.20%
Fixed Rate Riders	$ -	1	$ -	$ 0.16	1	$ 0.16	$ 0.16	
Volumetric Rate Riders	$ -	750	$ -	-$ 0.0001	750	$ (0.08)	$ (0.08)	
Sub-Total A (excluding pass through)			$ 33.48			$ 37.29	**$ 3.81**	**11.38%**
Line Losses on Cost of Power	$ 0.1114	53	$ 5.96	$ 0.1114	52	$ 5.80	$ (0.16)	-2.66%
Total Deferral/Variance Account Rate Riders	$ 0.0039	750	$ 2.93	-$ 0.0011	750	$ (0.83)	$ (3.75)	-128.21%
GA Rate Riders				$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0013	750	$ 0.98	$ 0.0016	750	$ 1.20	$ 0.23	23.08%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 44.12**			**$ 44.25**	**$ 0.13**	**0.29%**
RTSR - Network	$ 0.0059	803	$ 4.74	$ 0.0062	802	$ 4.97	$ 0.23	4.90%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0027	803	$ 2.17	$ 0.0028	802	$ 2.25	$ 0.08	3.52%
Sub-Total C - Delivery (including Sub-Total B)			**$ 51.03**			**$ 51.47**	**$ 0.43**	**0.85%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	803	$ 2.89	$ 0.0036	802	$ 2.89	$ (0.01)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	803	$ 1.69	$ 0.0021	802	$ 1.68	$ (0.00)	-0.18%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
Ontario Electricity Support Program (OESP)	$ 0.0011	802	$ 0.88	$ 0.0011	802	$ 0.88	$ -	0.00%
TOU - Off Peak	$ 0.0870	488	$ 42.41	$ 0.0870	488	$ 42.41	$ -	0.00%
TOU - Mid Peak	$ 0.1320	128	$ 16.83	$ 0.1320	128	$ 16.83	$ -	0.00%
TOU - On Peak	$ 0.1800	135	$ 24.30	$ 0.1800	135	$ 24.30	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 140.29**			**$ 140.71**	**$ 0.43**	**0.30%**
HST	13%		$ 18.24	13%		$ 18.29	$ 0.06	0.30%
Total Bill on TOU			**$ 158.52**			**$ 159.01**	**$ 0.48**	**0.30%**

Customer Class:	GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0713	
Proposed/Approved Loss Factor	1.0694	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 28.27	1	$ 28.27	$ 31.76	1	$ 31.76	$ 3.49	12.35%
Distribution Volumetric Rate	$ 0.0158	2000	$ 31.60	$ 0.0177	2000	$ 35.40	$ 3.80	12.03%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0009	2000	$ 1.80	$ 1.80	
Sub-Total A (excluding pass through)			$ 59.87			$ 68.96	**$ 9.09**	**15.18%**
Line Losses on Cost of Power	$ 0.1114	143	$ 15.88	$ 0.1114	139	$ 15.46	$ (0.42)	-2.66%
Total Deferral/Variance Account Rate Riders	$ 0.0039	2,000	$ 7.80	-$ 0.0009	2,000	$ (1.80)	$ (9.60)	-123.08%
GA Rate Riders				$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0012	2,000	$ 2.40	$ 0.0015	2,000	$ 3.00	$ 0.60	25.00%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 86.74**			**$ 86.41**	**$ (0.33)**	**-0.38%**
RTSR - Network	$ 0.0056	2,143	$ 12.00	$ 0.0059	2,139	$ 12.62	$ 0.62	5.17%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0026	2,143	$ 5.57	$ 0.0027	2,139	$ 5.77	$ 0.20	3.66%
Sub-Total C - Delivery (including Sub-Total B)			**$ 104.31**			**$ 104.80**	**$ 0.49**	**0.47%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	2,143	$ 7.71	$ 0.0036	2,139	$ 7.70	$ (0.01)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	2,143	$ 4.50	$ 0.0021	2,139	$ 4.49	$ (0.01)	-0.18%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	2,139	$ 2.35	$ 0.0011	2,139	$ 2.35	$ -	0.00%
TOU - Off Peak	$ 0.0870	1,300	$ 113.10	$ 0.0870	1,300	$ 113.10	$ -	0.00%
TOU - Mid Peak	$ 0.1320	340	$ 44.88	$ 0.1320	340	$ 44.88	$ -	0.00%
TOU - On Peak	$ 0.1800	360	$ 64.80	$ 0.1800	360	$ 64.80	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 355.91**			**$ 356.38**	**$ 0.47**	**0.13%**
HST	13%		$ 46.27	13%		$ 46.33	$ 0.06	0.13%
Total Bill on TOU			**$ 402.18**			**$ 402.71**	**$ 0.53**	**0.13%**

Customer Class:	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	66,182 kWh
Demand	195 kW
Current Loss Factor	1.0713
Proposed/Approved Loss Factor	1.0694

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 191.60	1	$ 191.60	$ 191.60	1	$ 191.60	$ -	0.00%
Distribution Volumetric Rate	$ 0.9177	195	$ 178.95	$ 1.1043	195	$ 215.34	$ 36.39	20.33%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	195	$ -	-$ 0.0013	195	$ (0.25)	$ (0.25)	
Sub-Total A (excluding pass through)			$ 370.55			$ 406.69	**$ 36.13**	**9.75%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 1.5701	195	$ 306.17	-$ 0.2765	195	$ (53.92)	$ (360.09)	-117.61%
GA Rate Riders				$ 0.0002	66,182	$ 13.24	$ 13.24	
Low Voltage Service Charge	$ 0.4340	195	$ 84.63	$ 0.5377	195	$ 104.85	$ 20.22	23.89%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 761.35**			**$ 470.86**	**$ (290.50)**	**-38.16%**
RTSR - Network	$ 2.2317	195	$ 435.18	$ 2.3529	195	$ 458.82	$ 23.63	5.43%
RTSR - Connection and/or Line and Transformation Connection	$ 0.9898	195	$ 193.01	$ 1.0401	195	$ 202.82	$ 9.81	5.08%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,389.54**			**$ 1,132.49**	**$ (257.05)**	**-18.50%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	70,901	$ 255.24	$ 0.0036	70,775	$ 254.79	$ (0.45)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	70,901	$ 148.89	$ 0.0021	70,775	$ 148.63	$ (0.26)	-0.18%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	66,182	$ 463.27	$ 0.0070	66,182	$ 463.27	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	70,775	$ 77.85	$ 0.0011	70,775	$ 77.85	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1130	70,901	$ 8,011.79	$ 0.1130	70,775	$ 7,997.58	$ (14.21)	-0.18%
Total Bill on Average IESO Wholesale Market Price			**$ 10,346.59**			**$ 10,074.61**	**$ (271.98)**	**-2.63%**
HST	13%		$ 1,345.06	13%		$ 1,309.70	$ (35.36)	-2.63%
Total Bill on Average IESO Wholesale Market Price			**$ 11,691.65**			**$ 11,384.31**	**$ (307.34)**	**-2.63%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	599 kWh
Demand	- kW
Current Loss Factor	1.0713
Proposed/Approved Loss Factor	1.0694

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 14.73	1	$ 14.73	$ 16.10	1	$ 16.10	$ 1.37	9.30%
Distribution Volumetric Rate	$ 0.0161	599	$ 9.64	$ 0.0176	599	$ 10.54	$ 0.90	9.32%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	599	$ -	-$ 0.0002	599	$ (0.12)	$ (0.12)	
Sub-Total A (excluding pass through)			$ 24.37			$ 26.52	**$ 2.15**	**8.82%**
Line Losses on Cost of Power	$ 0.1114	43	$ 4.76	$ 0.1114	42	$ 4.63	$ (0.13)	-2.66%
Total Deferral/Variance Account Rate Riders	$ 0.0040	599	$ 2.40	-$ 0.0009	599	$ (0.54)	$ (2.94)	-122.50%
GA Rate Riders				$ -	599	$ -	$ -	
Low Voltage Service Charge	$ 0.0012	599	$ 0.72	$ 0.0015	599	$ 0.90	$ 0.18	25.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 32.25**			**$ 31.51**	**$ (0.73)**	**-2.27%**
RTSR - Network	$ 0.0056	642	$ 3.59	$ 0.0059	641	$ 3.78	$ 0.19	5.17%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0026	642	$ 1.67	$ 0.0027	641	$ 1.73	$ 0.06	3.66%
Sub-Total C - Delivery (including Sub-Total B)			**$ 37.51**			**$ 37.02**	**$ (0.49)**	**-1.30%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	642	$ 2.31	$ 0.0036	641	$ 2.31	$ (0.00)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	642	$ 1.35	$ 0.0021	641	$ 1.35	$ (0.00)	-0.18%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	599	$ 4.19	$ 0.0070	599	$ 4.19	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	641	$ 0.70	$ 0.0011	641	$ 0.70	$ -	0.00%
TOU - Off Peak	$ 0.0870	389	$ 33.87	$ 0.0870	389	$ 33.87	$ -	0.00%
TOU - Mid Peak	$ 0.1320	102	$ 13.44	$ 0.1320	102	$ 13.44	$ -	0.00%
TOU - On Peak	$ 0.1800	108	$ 19.41	$ 0.1800	108	$ 19.41	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 113.04**			**$ 112.54**	**$ (0.49)**	**-0.44%**
HST	13%		$ 14.69	13%		$ 14.63	$ (0.06)	-0.44%
Total Bill on TOU			**$ 127.73**			**$ 127.17**	**$ (0.56)**	**-0.44%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	28 kWh
Demand	0.080 kW
Current Loss Factor	1.0713
Proposed/Approved Loss Factor	1.0694

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 6.79	1	$ 6.79	$ 7.64	1	$ 7.64	$ 0.85	12.52%
Distribution Volumetric Rate	$ 8.0054	0.08	$ 0.64	$ 9.0038	0.08	$ 0.72	$ 0.08	12.47%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	0.08	$ -	-$ 0.1207	0.08	$ (0.01)	$ (0.01)	
Sub-Total A (excluding pass through)			$ 7.43			$ 8.35	**$ 0.92**	**12.38%**
Line Losses on Cost of Power	$ 0.1130	2	$ 0.23	$ 0.1130	2	$ 0.22	$ (0.01)	-2.66%
Total Deferral/Variance Account Rate Riders	$ 1.8252	0	$ 0.15	-$ 0.2856	0	$ (0.02)	$ (0.17)	-115.65%
GA Rate Riders				$ 0.0002	28	$ 0.01	$ 0.01	
Low Voltage Service Charge	$ 0.3351	0	$ 0.03	$ 0.4152	0	$ 0.03	$ 0.01	23.90%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 7.83**			**$ 8.59**	**$ 0.76**	**9.67%**
RTSR - Network	$ 1.6832	0	$ 0.13	$ 1.7746	0	$ 0.14	$ 0.01	5.43%
RTSR - Connection and/or Line and Transformation Connection	$ 0.7651	0	$ 0.06	$ 0.8040	0	$ 0.06	$ 0.00	5.08%
Sub-Total C - Delivery (including Sub-Total B)			**$ 8.02**			**$ 8.79**	**$ 0.77**	**9.57%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	30	$ 0.11	$ 0.0036	30	$ 0.11	$ (0.00)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	30	$ 0.06	$ 0.0021	30	$ 0.06	$ (0.00)	-0.18%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	28	$ 0.20	$ 0.0070	28	$ 0.20	$ -	0.00%
Ontario Electricity Support Program (OESP)	$ 0.0011	30	$ 0.03	$ 0.0011	30	$ 0.03	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1130	28	$ 3.16	$ 0.1130	28	$ 3.16	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 11.59**			**$ 12.36**	**$ 0.77**	**6.62%**
HST	13%		$ 1.51	13%		$ 1.61	$ 0.10	6.62%
Total Bill on Average IESO Wholesale Market Price			**$ 13.10**			**$ 13.96**	**$ 0.87**	**6.62%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0713
Proposed/Approved Loss Factor	1.0694

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 24.25	1	$ 24.25	$ 30.30	1	$ 30.30	$ 6.05	24.95%
Distribution Volumetric Rate	$ 0.0123	750	$ 9.23	$ 0.0092	750	$ 6.90	$ (2.33)	-25.20%
Fixed Rate Riders	$ -	1	$ -	$ 0.16	1	$ 0.16	$ 0.16	
Volumetric Rate Riders	$ -	750	$ -	-$ 0.0001	750	$ (0.08)	$ (0.08)	
Sub-Total A (excluding pass through)			$ 33.48			$ 37.29	**$ 3.81**	**11.38%**
Line Losses on Cost of Power	$ 0.1130	53	$ 6.04	$ 0.1130	52	$ 5.88	$ (0.16)	-2.66%
Total Deferral/Variance Account Rate Riders	$ 0.0051	750	$ 3.83	-$ 0.0011	750	$ (0.83)	$ (4.65)	-121.57%
GA Rate Riders				$ 0.0002	750	$ 0.15	$ 0.15	
Low Voltage Service Charge	$ 0.0013	750	$ 0.98	$ 0.0016	750	$ 1.20	$ 0.23	23.08%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 45.11**			**$ 44.48**	**$ (0.63)**	**-1.39%**
RTSR - Network	$ 0.0059	803	$ 4.74	$ 0.0062	802	$ 4.97	$ 0.23	4.90%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0027	803	$ 2.17	$ 0.0028	802	$ 2.25	$ 0.08	3.52%
Sub-Total C - Delivery (including Sub-Total B)			**$ 52.02**			**$ 51.70**	**$ (0.32)**	**-0.61%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	803	$ 2.89	$ 0.0036	802	$ 2.89	$ (0.01)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	803	$ 1.69	$ 0.0021	802	$ 1.68	$ (0.00)	-0.18%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)								
Ontario Electricity Support Program (OESP)	$ 0.0011	802	$ 0.88	$ 0.0011	802	$ 0.88	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1130	750	$ 84.75	$ 0.1130	750	$ 84.75	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 142.23**			**$ 141.90**	**$ (0.33)**	**-0.23%**
HST	13%		$ 18.49	13%		$ 18.45	$ (0.04)	-0.23%
Total Bill on Non-RPP Avg. Price			**$ 160.72**			**$ 160.35**	**$ (0.37)**	**-0.23%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	285	kWh
Demand	-	kW
Current Loss Factor	1.0713	
Proposed/Approved Loss Factor	1.0694	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 24.25	1	$ 24.25	$ 30.30	1	$ 30.30	$ 6.05	24.95%
Distribution Volumetric Rate	$ 0.0123	285	$ 3.51	$ 0.0092	285	$ 2.62	$ (0.88)	-25.20%
Fixed Rate Riders	$ -	1	$ -	$ 0.16	1	$ 0.16	$ 0.16	
Volumetric Rate Riders	$ -	285	$ -	-$ 0.0001	285	$ (0.03)	$ (0.03)	
Sub-Total A (excluding pass through)			$ 27.76			$ 33.05	**$ 5.30**	**19.09%**
Line Losses on Cost of Power	$ 0.1114	20	$ 2.26	$ 0.1114	20	$ 2.20	$ (0.06)	-2.66%
Total Deferral/Variance Account Rate Riders	$ 0.0039	285	$ 1.11	-$ 0.0011	285	$ (0.31)	$ (1.43)	-128.21%
GA Rate Riders				$ -	285	$ -	$ -	
Low Voltage Service Charge	$ 0.0013	285	$ 0.37	$ 0.0016	285	$ 0.46	$ 0.09	23.08%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 32.29**			**$ 36.19**	**$ 3.90**	**12.07%**
RTSR - Network	$ 0.0059	305	$ 1.80	$ 0.0062	305	$ 1.89	$ 0.09	4.90%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0027	305	$ 0.82	$ 0.0028	305	$ 0.85	$ 0.03	3.52%
Sub-Total C - Delivery (including Sub-Total B)			**$ 34.92**			**$ 38.93**	**$ 4.02**	**11.50%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	305	$ 1.10	$ 0.0036	305	$ 1.10	$ (0.00)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	305	$ 0.64	$ 0.0021	305	$ 0.64	$ (0.00)	-0.18%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
Ontario Electricity Support Program (OESP)	$ 0.0011	305	$ 0.34	$ 0.0011	305	$ 0.34	$ -	0.00%
TOU - Off Peak	$ 0.0870	185	$ 16.12	$ 0.0870	185	$ 16.12	$ -	0.00%
TOU - Mid Peak	$ 0.1320	48	$ 6.40	$ 0.1320	48	$ 6.40	$ -	0.00%
TOU - On Peak	$ 0.1800	51	$ 9.23	$ 0.1800	51	$ 9.23	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 68.99**			**$ 73.00**	**$ 4.01**	**5.82%**
HST	13%		$ 8.97	13%		$ 9.49	$ 0.52	5.82%
Total Bill on TOU			**$ 77.96**			**$ 82.49**	**$ 4.53**	**5.82%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	285	kWh
Demand	-	kW
Current Loss Factor	1.0713	
Proposed/Approved Loss Factor	1.0694	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 24.25	1	$ 24.25	$ 30.30	1	$ 30.30	$ 6.05	24.95%
Distribution Volumetric Rate	$ 0.0123	285	$ 3.51	$ 0.0092	285	$ 2.62	$ (0.88)	-25.20%
Fixed Rate Riders	$ -	1	$ -	$ 0.16	1	$ 0.16	$ 0.16	
Volumetric Rate Riders	$ -	285	$ -	-$ 0.0001	285	$ (0.03)	$ (0.03)	
Sub-Total A (excluding pass through)			$ 27.76			$ 33.05	**$ 5.30**	**19.09%**
Line Losses on Cost of Power	$ 0.1130	20	$ 2.30	$ 0.1130	20	$ 2.24	$ (0.06)	-2.66%
Total Deferral/Variance Account Rate Riders	$ 0.0051	285	$ 1.45	-$ 0.0011	285	$ (0.31)	$ (1.77)	-121.57%
GA Rate Riders				$ 0.0002	285	$ 0.06	$ 0.06	
Low Voltage Service Charge	$ 0.0013	285	$ 0.37	$ 0.0016	285	$ 0.46	$ 0.09	23.08%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 32.67**			**$ 36.28**	**$ 3.61**	**11.06%**
RTSR - Network	$ 0.0059	305	$ 1.80	$ 0.0062	305	$ 1.89	$ 0.09	4.90%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0027	305	$ 0.82	$ 0.0028	305	$ 0.85	$ 0.03	3.52%
Sub-Total C - Delivery (including Sub-Total B)			**$ 35.29**			**$ 39.02**	**$ 3.73**	**10.57%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	305	$ 1.10	$ 0.0036	305	$ 1.10	$ (0.00)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0021	305	$ 0.64	$ 0.0021	305	$ 0.64	$ (0.00)	-0.18%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)								
Ontario Electricity Support Program (OESP)	$ 0.0011	305	$ 0.34	$ 0.0011	305	$ 0.34	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1130	285	$ 32.21	$ 0.1130	285	$ 32.21	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 69.57**			**$ 73.30**	**$ 3.73**	**5.36%**
HST	13%		$ 9.04	13%		$ 9.53	$ 0.48	5.36%
Total Bill on Non-RPP Avg. Price			**$ 78.62**			**$ 82.83**	**$ 4.21**	**5.36%**

Attachment 4

2016 Fixed Asset Continuity:

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2016**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 52,657	$ 375,251		$ 427,908	-$ 42,433	-$ 47,749		-$ 90,182	$ 337,725
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700	$ -			$ -	$ 87,700
47	1808	Buildings	$ 462,384			$ 462,384	-$ 40,127	-$ 19,373		-$ 59,500	$ 402,884
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 221,248	$ 53,197		$ 274,445	-$ 39,467	-$ 20,834		-$ 60,301	$ 214,144
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,033,839	$ 184,042		$ 2,217,881	-$ 249,892	-$ 133,238		-$ 383,130	$ 1,834,751
47	1835	Overhead Conductors & Devices	$ 1,136,526	$ 159,723		$ 1,296,249	-$ 68,286	-$ 38,324		-$ 106,610	$ 1,189,639
47	1840	Underground Conduit	$ 9,548			$ 9,548	-$ 2,728	-$ 1,364		-$ 4,092	$ 5,456
47	1845	Underground Conductors & Devices	$ 2,111			$ 2,111	-$ 603	-$ 301		-$ 904	$ 1,207
47	1850	Line Transformers	$ 562,955	$ 65,576		$ 628,531	-$ 37,175	-$ 22,774		-$ 59,949	$ 568,582
47	1855	Services (Overhead & Underground)	$ 237,442	$ 882		$ 238,324	-$ 20,748	-$ 12,634		-$ 33,382	$ 204,942
47	1860	Meters	$ 20,905	$ 678		$ 21,583	-$ 4,379	-$ 2,304		-$ 6,683	$ 14,900
47	1860	Meters (Smart Meters)	$ 667,552	$ 7,687		$ 675,239	-$ 124,558	-$ 60,224		-$ 184,782	$ 490,457
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 470			$ 470	-$ 470			-$ 470	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 682	$ 1,807		$ 2,489	-$ 383	-$ 189		-$ 572	$ 1,917
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 10,025	$ 15,735		$ 25,760	-$ 4,125	-$ 4,174		-$ 8,299	$ 17,462
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,363			$ 348,363	-$ 68,230	-$ 33,500		-$ 101,730	$ 246,633
10	1930	Transportation Equipment	$ 1,275,651	$ 87,180		$ 1,362,831	-$ 458,613	-$ 201,980		-$ 660,593	$ 702,238
8	1935	Stores Equipment	$ 877			$ 877	-$ 564	-$ 175		-$ 739	$ 138
8	1940	Tools, Shop & Garage Equipment	$ 78,376	$ 10,485		$ 88,861	-$ 49,556	-$ 15,061		-$ 64,617	$ 24,244
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 1,186			$ 1,186	-$ 1,186			-$ 1,186	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 123,412			-$ 123,412	$ 1,409	$ 2,850		$ 4,259	-$ 119,153
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 7,087,085**	**$ 962,243**	**$ -**	**$ 8,049,328**	**-$ 1,212,114**	**-$ 611,349**	**$ -**	**-$ 1,823,463**	**$ 6,225,865**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 7,087,085**	**$ 962,243**	**$ -**	**$ 8,049,328**	**-$ 1,212,114**	**-$ 611,349**	**$ -**	**-$ 1,823,463**	**$ 6,225,865**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 611,349**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 201,980
Stores Equipment	-$ 19,373
Net Depreciation	-$ 389,996

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

2017 Fixed Asset Continuity:

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard	MIFRS
Year	**2017**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 427,908	$ 115,000		$ 542,908	-$ 90,182	-$ 86,550		-$ 176,733	$ 366,175
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700	$ -			$ -	$ 87,700
47	1808	Buildings	$ 462,384			$ 462,384	-$ 59,500	-$ 19,373		-$ 78,873	$ 383,511
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 274,445	$ 50,000		$ 324,445	-$ 60,301	-$ 20,970		-$ 81,272	$ 243,173
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,217,881	$ 367,500		$ 2,585,381	-$ 383,130	-$ 139,413		-$ 522,543	$ 2,062,838
47	1835	Overhead Conductors & Devices	$ 1,296,249	$ 101,250		$ 1,397,499	-$ 106,610	-$ 41,264		-$ 147,874	$ 1,249,624
47	1840	Underground Conduit	$ 9,548			$ 9,548	-$ 4,092	-$ 1,364		-$ 5,456	$ 4,092
47	1845	Underground Conductors & Devices	$ 2,111			$ 2,111	-$ 904	-$ 301		-$ 1,205	$ 906
47	1850	Line Transformers	$ 628,531	$ 101,250		$ 729,781	-$ 59,949	-$ 24,612		-$ 84,561	$ 645,220
47	1855	Services (Overhead & Underground)	$ 238,324			$ 238,324	-$ 33,382	-$ 12,643		-$ 46,025	$ 192,299
47	1860	Meters	$ 21,583			$ 21,583	-$ 6,683	-$ 1,964		-$ 8,647	$ 12,936
47	1860	Meters (Smart Meters)	$ 675,239	$ 15,000		$ 690,239	-$ 184,782	-$ 60,980		-$ 245,761	$ 444,477
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 470			$ 470	-$ 470			-$ 470	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 2,489			$ 2,489	-$ 572	-$ 318		-$ 890	$ 1,599
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 25,760	$ 10,000		$ 35,760	-$ 8,299	-$ 6,447		-$ 14,746	$ 21,015
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,363			$ 348,363	-$ 101,730	-$ 32,885		-$ 134,615	$ 213,748
10	1930	Transportation Equipment	$ 1,362,831			$ 1,362,831	-$ 660,593	-$ 190,149		-$ 850,742	$ 512,089
8	1935	Stores Equipment	$ 877			$ 877	-$ 739	-$ 68		-$ 807	$ 70
8	1940	Tools, Shop & Garage Equipment	$ 88,861	$ 17,500		$ 106,361	-$ 64,617	-$ 11,948		-$ 76,565	$ 29,796
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 1,186			$ 1,186	-$ 1,186			-$ 1,186	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 123,412			-$ 123,412	$ 4,259	$ 2,850		$ 7,109	-$ 116,303
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 8,049,328**	**$ 777,500**	**$ -**	**$ 8,826,828**	**-$ 1,823,463**	**-$ 648,399**	**$ -**	**-$ 2,471,862**	**$ 6,354,966**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 8,049,328**	**$ 777,500**	**$ -**	**$ 8,826,828**	**-$ 1,823,463**	**-$ 648,399**	**$ -**	**-$ 2,471,862**	**$ 6,354,966**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 648,399**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 190,149
Stores Equipment	-$ 19,373
Net Depreciation	-$ 438,877

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Attachment 5

Northern Ontario Wires Inc.

Accounting Order – 1508 Other Regulatory Assets, Sub-account OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account

For greater clarity, this accounting order is intended to reflect the OEB's Decision in EB-2016-0096. NOW Inc. Inc. ("NOW Inc.") shall establish the following deferral account effective January 1, 2017:

Account 1508 Other Regulatory Assets, Sub-account – OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account

NOW Inc. 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 the OM&A components of OPEBs accounted for using a forecasted cash basis and the 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, NOW Inc. 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, NOW Inc. will seek disposition of this account to recover the amounts so recorded in its next cost of service rate application.

NOW Inc. 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.

No carrying charges shall be recorded on this account.

Sample Journal Entries

Illustration Assumptions:

- OPEB cost on accrual basis is $35,000
- OPEB cost on cash basis is $25,000
- Difference in OPEB costs $10,000 ($35,000 - $25,000)
- All OPEB costs are allocated to OM&A
- OPEB costs are incurred evenly throughout the year.

Debit	Account 1508 Other Regulatory Assets, Subaccount – OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account	$10,000	Balance Sheet
Credit	5000 OM&A - Various	($10,000)	Income Statement
To record the difference between OPEBs accounted for using a cash basis and a forecasted accrual basis.			