EB-2016-0061

# CANADIAN NIAGARA POWER INC.

# HEARING MATERIALS

FILED: JANURARY 3, 2017

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**INDEX**

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# Tab 1 – Partial Settlement Proposal

Canadian Niagara Power Inc.

2017 Cost of Service Application

Settlement Proposal

EB-2016-0061

Filed: December 1, 2016

## Contents

# LIST OF ATTACHMENTS

A. Revenue Requirement Workform
B. 2016 and 2017 Fixed Asset Continuity Schedule

Note:

Canadian Niagara Power 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) Filing Requirements Chapter 2 Appendices
b) 2017 Revenue Requirement Workform
c) 2017 Test Year Income Tax PILs Model
d) 2017 Cost Allocation Model

The models listed below do not require changes as a result of this Settlement Proposal, and therefore have not been revised. The most current versions of these models have been filed in conjunction with Interrogatory Responses, or in conjunction with Technical Conference Undertakings, as required:

a) 2017 Load Forecast Model – Wholesale
b) 2017 EDDVAR Continuity Schedule
c) 2017 RTSR Model
d) LRAMVA Model & Burman Report

# SETTLEMENT PROPOSAL

Canadian Niagara Power Inc. (the "Applicant" or "CNPI") filed a Cost of Service application with the Ontario Energy Board (the "OEB") on April 29, 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 CNPI charges for electricity distribution, to be effective January 1, 2017 (OEB file number EB-2016-0061) (the "Application").

The OEB issued a Letter of Direction and Notice of Application on August 17, 2016. In Procedural Order No. 1, dated September 16, 2016, the OEB approved VECC, Energy Probe, and SEC for intervenor status as well as prescribing dates for the following: written interrogatories from OEB staff, VECC, Energy Probe, and SEC; CNPI's responses to interrogatories; a Technical Conference and a Settlement Conference; and various other elements in the proceeding.

Following the receipt of interrogatories, CNPI filed its interrogatory responses with the OEB on October 19, 2016.

On November 3, 2016, following interrogatories, OEB Staff submitted a proposed issues list as agreed to by the parties. On November 11, 2016 the OEB issued its decision on the proposed issues list, approving the list submitted by OEB staff as the final issues list (the "Issues List").

The settlement conference was convened on November 8 and 9, 2016 in accordance with the OEB's *Rules of Practice and Procedure* (the "Rules") and the OEB's Practice Direction on Settlement Conferences (the "Practice Direction"). Mr. Chris Haussmann acted as facilitator for the settlement conference.

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

- Vulnerable Energy Consumers Coalition ("VECC");
- Energy Probe Research Foundation ("EP" or "Energy Probe");
- School Energy Coalition ("SEC").

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

Included with the Settlement Proposal are Attachments that provide further support for the proposed settlement. The Parties acknowledge that the Attachments were prepared by CNPI. While the Intervenors 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 many of the issues in this proceeding, with only the following 5 discrete issues going to hearing:

- Issue 1.2 OM&A, no settlement, full issue to hearing.

- Issue 2.1.1 Cost of Capital, partial settlement, the issue of whether and how expected changes in the cost of long-term debt in 2018 should be reflected in rates will go to hearing.

- Issue 4.1 Accounting Standards etc., partial settlement, the discrete issue of the appropriate accounting for Pension and OPEB costs in rates (cash vs. accrual) will go to hearing.

- Issue 4.2 Deferral and Variance Accounts, partial settlement, the issue of whether a variance account related to pension and OPEBs is appropriate will go to hearing, and the issue of whether a variance account should be established for future changes to the cost of long-term debt will go to hearing.

- Issue 4.2.1 Effective Date, no settlement, the issue of whether rates should be effective January 1, 2017 will go to hearing.

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 CNPI 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 CNPI, 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 partial settlement of the issues in the proceeding. The Parties have described below, in detail, areas where they have either settled an issue by agreeing to adjustments to the application as updated, and highlighted areas where one, some, or all aspects of an issue will be subject to a hearing by the Board.

For ease of reference, the following list contains all of the issues that will proceed to hearing if the Board accepts this Settlement Proposal:

- Issue 1.2 OM&A, no settlement, full issue to hearing.
- Issue 2.1.1 Cost of Capital, partial settlement, the issue of whether and how expected changes in the cost of long-term debt should be reflected in rates will go to hearing.
- Issue 4.1 Accounting Standards etc., partial settlement, the discrete issue of the appropriate accounting for Pension and OPEB costs in rates (cash vs. accrual) will go to hearing and the issue of whether a variance account should be established for future changes to the cost of long-term debt will go to hearing.
- Issue 4.2 Deferral and Variance Accounts, partial settlement, the issue of whether a variance account related to pension and OPEBs is appropriate will go to hearing.
- Issue 4.2.1 Effective Date, no settlement. The issue of whether rates should be effective January 1, 2017 will go to hearing.

Various other issues are fully settled in principle, but their final determination in support of rates depends in part on one or more of the issues that will go to hearing. Accordingly, while the Parties have noted those “consequential” issues as settled, the final calculations for such issues cannot be provided until the issues that are going to hearing are decided by the Board.

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. Some of this evidence may need to be updated subject to the OEB’s determination of the unsettled issues.

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, CNPI has agreed to certain adjustments to its original 2016 Application. The changes are described in the following sections.

CNPI has provided the following Table 1 highlighting the changes to its Rate Base and Capital, Operating Expenses and Revenue Requirement from CNPI's Application as filed as a result of interrogatories, technical conference questions and this Settlement Proposal. This Table, together with that of Table 2, and the other relevant Tables herein, does not reflect any further changes to the Application for the issues not settled and yet to be determined by the OEB.

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 | 6,456,937 | 6,129,330 | (327,608) | 6,128,463 | (866) |
| | Regulated Rate of Return | 7.18% | 6.84% | -0.34% | 6.84% | 0.00% |
| Rate Base & Capital Expenditures | Rate Base | 89,924,481 | 89,662,520 | (261,962) | 89,649,845 | (12,675) |
| | Working Capital | 72,787,072 | 75,183,128 | 2,396,056 | 75,014,128 | (169,000) |
| | Working Capital Allowance | 5,459,030 | 5,638,735 | 179,704 | 5,626,060 | (12,675) |
| Operating Expenses | Amortization/Depreciation | 4,766,329 | 4,724,996 | (41,333) | 4,724,996 | 0 |
| | Grossed up Income Taxes | 526,758 | 521,759 | (4,999) | 521,599 | (161) |
| | Property Taxes | 103,000 | 103,000 | 0 | 103,000 | 0 |
| | OM&A | 10,441,723 | 10,471,723 | 30,000 | 10,471,723 | 0 |
| Revenue Requirement | Service Revenue Requirement | 22,294,747 | 21,950,808 | (343,939) | 21,949,781 | (1,027) |
| | Other Revenues | 2,424,445 | 2,448,193 | 23,748 | 2,548,193 | 100,000 |
| | Base Revenue Requirement | 19,870,302 | 19,502,615 | (367,687) | 19,401,588 | (101,027) |
| | Grossed up Revenue Deficiency / (Sufficiency) | 2,316,325 | 1,769,650 | (546,675) | 1,668,623 | (101,027) |

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

Table 2 below illustrates the updated Bill Impacts based on the results of this Settlement Proposal, which are subject to change as a result of the determination of the outstanding issues.

# Table 2: Bill Impact Summary

**Bill Impact Summary - Fort Erie**

| Customer Classification and Billing Type | Energy kWh | Demand kW | Total Bill | | | |
|---|---|---|---|---|---|---|
| | | | Current Rates | Partial Settlement | Change | |
| | | | | | $ | % |
| Residential; TOU | 750 | | 157.55 | 156.72 | (0.83) | (0.53%) |
| GS<50 kW | 2,000 | | 392.12 | 392.68 | 0.56 | 0.14% |
| GS>50 kW | 20,000 | 60 | 3,825.76 | 4,036.03 | 210.27 | 5.50% |
| USL | 3,500 | | 647.69 | 675.40 | 27.71 | 4.28% |
| Sentinel Lighting | 1,400 | 5 | 355.13 | 361.89 | 6.76 | 1.90% |
| Street Lighting | 5,400 | 15 | 1,713.23 | 1,572.34 | (140.89) | (8.22%) |
| Residential (10th %); TOU | 210 | | 64.03 | 68.57 | 4.54 | 7.09% |
| Residential (10th %); Retailer | 210 | | 75.64 | 82.42 | 6.78 | 8.96% |

**Bill Impact Summary - EOP**

| Customer Classification and Billing Type | Energy kWh | Demand kW | Total Bill | | | |
|---|---|---|---|---|---|---|
| | | | Current Rates | Partial Settlement | Change | |
| | | | | | $ | % |
| Residential; TOU | 750 | | 155.17 | 156.72 | 1.55 | 1.00% |
| GS<50 kW | 2,000 | | 397.77 | 404.21 | 6.44 | 1.62% |
| GS>50 kW | 20,000 | 60 | 4,278.76 | 4,151.29 | (127.47) | (2.98%) |
| USL | 3,500 | | 657.18 | 695.57 | 38.39 | 5.84% |
| Sentinel Lighting | 1,400 | 5 | 362.05 | 369.96 | 7.91 | 2.18% |
| Street Lighting | 5,400 | 15 | 1,821.86 | 1,603.46 | (218.40) | (11.99%) |
| Residential (10th %); TOU | 210 | | 63.37 | 68.57 | 5.20 | 8.21% |
| Residential (10th %); Retailer | 210 | | 78.96 | 82.42 | 3.46 | 4.38% |

**Bill Impact Summary - Port Colborne**

| Customer Classification and Billing Type | Energy kWh | Demand kW | Total Bill | | | |
|---|---|---|---|---|---|---|
| | | | Current Rates | Partial Settlement | Change | |
| | | | | | $ | % |
| Residential; TOU | 750 | | 156.11 | 156.72 | 0.61 | 0.39% |
| GS<50 kW | 2,000 | | 404.10 | 408.50 | 4.40 | 1.09% |
| GS>50 kW | 20,000 | 60 | 3,912.40 | 4,194.23 | 281.83 | 7.20% |
| Embedded Distributor | 433,813 | 1,160 | 79,550.01 | 85,315.54 | 5,765.53 | 7.25% |
| USL | 3,500 | | 665.88 | 703.09 | 37.21 | 5.59% |
| Sentinel Lighting | 1,400 | 5 | 370.51 | 372.97 | 2.46 | 0.66% |
| Street Lighting | 5,400 | 15 | 1,743.79 | 1,615.05 | (128.74) | (7.38%) |
| Residential (10th %); TOU | 210 | | 63.63 | 68.57 | 4.94 | 7.76% |
| Residential (10th %); Retailer | 210 | | 74.72 | 82.42 | 7.70 | 10.31% |

## 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). For the purpose of the settlement of the issues in this proceeding, and subject to the adjustments noted in this Settlement Proposal, the Parties accept that CNPI'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;
- Compatibility with historical expenditures;
- Compatibility with applicable benchmarks;
- Reliability and service quality;
- Impact on distribution rates;
- Trade-offs with OM&A spending;
- Government-mandated obligations; and
- The objectives of Canadian Niagara Power and its customers.

### Complete Settlement

The Parties accept the 2017 capital expenditures as appropriate.

The Parties note that the sub-issues relating to “Productivity” and “Trade-offs with OM&A spending”, while settled in relation to the proposed Capital Plan, remain unsettled to the extent that they relate to the appropriateness of the proposed OM&A budget under unsettled issue 1.2 “OM&A”.

A summary of gross capital expenditures is presented in Table 3 below.

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 | 908,897 | 908,897 | 0 | 908,897 | 0 |
| System Renewal | 4,990,817 | 4,990,817 | 0 | 4,990,817 | 0 |
| System Service | 1,841,678 | 1,841,678 | 0 | 1,841,678 | 0 |
| General Plant | 2,015,766 | 2,015,766 | 0 | 2,015,766 | 0 |
| **Total Expenditure** | **9,757,158** | **9,757,158** | **0** | **9,757,158** | **0** |

For the purposes of settlement of all the issues in this proceeding, the Parties accept the evidence of CNPI 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.

Evidence References

- Ex.1/Tab 1/Sch.2 – Management Discussion and Analysis
- Ex.1/Tab 2/Sch.4 – Rate Base and Capital Plan
- Ex.1/Tab 10/Sch.2 – Impact of RRFE on the Current Application
- Exhibit 2: Rate Base, Including Ex.2/Tab 2/Sch.1/App.A – Distribution System Plan

IR Responses

- 2-Staff-18 to 2-Staff-56
- 2-Energy Probe-5 to 2-Energy Probe-9
- 2-VECC-7 to 2-VECC-16

Technical Conference Undertakings

- None

Supporting Parties

All

## 1.2 OM&A

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

- Customer feedback and preferences;
- Productivity;
- Compatibility with historical expenditures;
- Compatibility with applicable benchmarks;
- Reliability and service quality;
- Impact on distribution rates;
- Trade-offs with capital spending;
- Government-mandated obligations; and
- The objectives of Canadian Niagara Power and its customers.

No Settlement

The issue of OM&A is not settled and will proceed to hearing.

A summary of the OM&A expenditures, adjusted for IR responses and answers given at the technical conference is presented in Table 4 below for the purposes of the hearing of this issue.

The parties specifically note that one aspect of the unsettled OM&A issue relates to the accounting treatment for Pension and OPEB costs in rates, including the possibility of a new variance account related to Pension and OPEB costs; accordingly the related issues 4.1 and 4.2 remain unsettled in recognition of the Pension and OPEB cost issue, described in more detail under those issues.

Table 4: 2017 Test Year OM&A Expenditures

| Description | Application (A) | IR/TC Responses (B) | Variance (C) = (B) - (A) |
|---|---|---|---|
| Operations | 1,847,897 | 1,847,897 | 0 |
| Maintenance | 2,259,049 | 2,259,049 | 0 |
| Billing and Collecting | 1,960,026 | 1,960,026 | 0 |
| Community Relations | 40,150 | 40,150 | 0 |
| Administrative and General | 4,437,601 | 4,467,601 | 30,000 |
| **Total Expenditure** | **10,544,723** | **10,574,723** | 30,000 |

Not Settled

## Evidence References

- Ex.1/Tab 1/Sch.2 – Management Discussion and Analysis
- Ex.1/Tab 2/Sch.5 – Operations, Maintenance and Administrative Expense
- Ex.1/Tab 10/Sch.2 – Impact of RRFE on the Current Application
- Exhibit 4: Operating Costs

## IR Responses

- 4-Staff-58 to 4-Staff-82
- 4-Energy Probe-14 to 4-Energy Probe-16
- 4-VECC-25 to 4-VECC-30

## Technical Conference Undertakings

- None

## Supporting Parties

All

# 2 REVENUE REQUIREMENT

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

### Complete Settlement

This issue is settled to the extent that the parties agree that the methodology used by CNPI to calculate the Revenue Requirement is appropriate. However, as that calculation relies on inputs from issues that remain outstanding, the final calculation cannot be performed until the incorporation of the results of the Board's decision on unsettled issues.

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 | 6,456,937 | 6,129,330 | (327,608) | 6,128,463 | (866) |
| | Regulated Rate of Return | 7.18% | 6.84% | -0.34% | 6.84% | 0.00% |
| Rate Base & Capital Expenditures | Rate Base | 89,924,481 | 89,662,520 | (261,962) | 89,649,845 | (12,675) |
| | Working Capital | 72,787,072 | 75,183,128 | 2,396,056 | 75,014,128 | (169,000) |
| | Working Capital Allowance | 5,459,030 | 5,638,735 | 179,704 | 5,626,060 | (12,675) |
| Operating Expenses | Amortization/Depreciation | 4,766,329 | 4,724,996 | (41,333) | 4,724,996 | 0 |
| | Grossed up Income Taxes | 526,758 | 521,759 | (4,999) | 521,599 | (161) |
| | Property Taxes | 103,000 | 103,000 | 0 | 103,000 | 0 |
| | OM&A | 10,441,723 | 10,471,723 | 30,000 | 10,471,723 | 0 |
| Revenue Requirement | Service Revenue Requirement | 22,294,747 | 21,950,808 | (343,939) | 21,949,781 | (1,027) |
| | Other Revenues | 2,424,445 | 2,448,193 | 23,748 | 2,548,193 | 100,000 |
| | Base Revenue Requirement | 19,870,302 | 19,502,615 | (367,687) | 19,401,588 | (101,027) |
| | Grossed up Revenue Deficiency / (Sufficiency) | 2,316,325 | 1,769,650 | (546,675) | 1,668,623 | (101,027) |

An updated Revenue Requirement Work Form Model has been filed though the OEB's e-filing service.

### Evidence References

- Ex.1/Tab 2/Sch.1 – Revenue Requirement
- Exhibit 6
- Test Year RRWF

### IR Responses

- 6-Energy Probe-19
- Updated RRWF

## Technical Conference Undertakings

- JTC1.1
- JTC1.3
- Updated RRWF

## Supporting Parties

All

## 2.1.1 Cost of Capital

### Partial Settlement

The Parties agree to CNPI's proposed cost of capital parameters as updated to reflect the Board's deemed cost of capital parameters for the 2017 test year. The parties note that any changes to the cost of capital calculations that result from the Board's decision on unsettled issues will be recognized in an update to these calculations.

The parties have not agreed on whether it is appropriate to recognize and if so how to recognize in revenue requirement or rates any differential between the Applicant's cost of long term debt and current market rates for long term debt, or any change in the cost of long-term debt in 2018.

Table 6 below details the cost of capital calculation.

Table 6: Cost of Capital Calculation

**Initial Application**

| | | (%) | ($) | (%) | | ($) |
|---|---|---|---|---|---|---|
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | $50,357,710 | 6.14% | | $3,091,963 |
| 2 | Short-term Debt | 4.00% | $3,596,979 | 1.65% | | $59,350 |
| 3 | **Total Debt** | 60.00% | $53,954,689 | 5.84% | | $3,151,314 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | $35,969,793 | 9.19% | | $3,305,624 |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | | $ - |
| 6 | **Total Equity** | 40.00% | $35,969,793 | 9.19% | | $3,305,624 |
| 7 | **Total** | 100.00% | $89,924,481 | 7.18% | | $6,456,937 |

**Settlement Agreement**

| | | (%) | ($) | (%) | | ($) |
|---|---|---|---|---|---|---|
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | $50,203,913 | 5.81% | (1) | $2,916,847 |
| 2 | Short-term Debt | 4.00% | $3,585,994 | 1.76% | (1) | $63,113 |
| 3 | **Total Debt** | 60.00% | $53,789,907 | 5.54% | | $2,979,961 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | $35,859,938 | 8.78% | (1) | $3,148,503 |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | | $ - |
| 6 | **Total Equity** | 40.00% | $35,859,938 | 8.78% | | $3,148,503 |
| 7 | **Total** | 100.00% | $89,649,845 | 6.84% | | $6,128,463 |

**Notes**

(1) Cost of capital rate changes per JTC 1.1. Additional changes in $ amounts due to cumulative impact of adjustments required based on IR and TC responses.

## Evidence References

- Ex.1/Tab 2/Sch.6 – Cost of Capital
- Exhibit 5 – Capital Structure

IR Responses
- 5-Staff-84
- 5-Energy Probe-18
- 5-VECC-32

Technical Conference Undertakings
- None

Supporting Parties
All

### 2.1.2 Rate Base

#### Complete Settlement

The Parties accept the evidence of CNPI that the rate base calculations, after making the adjustment to the working capital rate base as detailed in this Settlement Proposal, is reasonable and have been appropriately determined in accordance with OEB policies and practices. Table 7 below outlines CNPI's Rate Base calculation. However as there are unsettled issues that impact the final Rate Base calculation, the issue remains unsettled until unsettled issues that are proceeding to hearing are resolved.

Table 7: Rate Base

| Description | Application (A) | IR/TC Responses (B) | Variance (C) = (B) - (A) | Settlement (D) | Variance (E) = (D) - (B) |
|---|---|---|---|---|---|
| Gross Fixed Assets (Average) | 147,209,031 | 146,726,031 | (483,000) | 146,726,031 | 0 |
| Accumulated Depreciation (Average) | (62,743,580) | (62,702,246) | 41,334 | (62,702,246) | 0 |
| Net Fixed Assets (Average) | 84,465,451 | 84,023,785 | (441,666) | 84,023,785 | 0 |
| | | | | | |
| Working Capital Base | 72,787,072 | 75,183,128 | 2,396,056 | 75,014,128 | (169,000) |
| Working Capital Allowance (%) | 7.5% | 7.5% | 0.0% | 7.5% | 0 |
| | | | | | |
| Allowance for Working Capital | 5,459,030 | 5,638,735 | 179,704 | 5,626,060 | (12,675) |
| **Total Rate Base** | **89,924,481** | **89,662,520** | **(261,962)** | **89,649,845** | **(12,675)** |

Note - Placeholder values used for the following unsettled items:
Working Capital Base (Settled with exception of OM&A component)
Allowance for Working Capital (Settled with exception of OM&A impact on Working Capital Base)
Total Rate Base (calculation includes both settled and placeholder values)

#### Evidence References

- Ex.1/Tab 2/Sch.4 – Rate Base and Capital Plan
- Exhibit 2

#### IR Responses

- 2-Staff-20
- 2-Energy Probe-5

#### Technical Conference Undertakings

- None

#### Supporting Parties

All

### 2.1.3 Working Capital Allowance

#### Complete Settlement

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

- The removal of amounts related to vehicle depreciation from the OM&A component of the calculation.

The Parties accepted the revised Working Capital Allowance amount incorporating the changes noted above. Table 8 below illustrates the calculation of the Working Capital Allowance, subject to any adjustments for components of the Working Capital Allowance calculation that are proceeding to hearing.

#### Table 8: Working Capital Allowance Calculation

| Description | Application (A) | IR/TC Responses (B) | Variance (C) = (B) - (A) | Settlement (D) | Variance (E) = (D) - (B) |
|---|---|---|---|---|---|
| Operations | 1,847,897 | 1,847,897 | 0 | 1,847,897 | 0 |
| Maintenance | 2,259,049 | 2,259,049 | 0 | 2,259,049 | 0 |
| Billing and Collecting | 1,960,026 | 1,960,026 | 0 | 1,960,026 | 0 |
| Community Relations | 43,150 | 43,150 | 0 | 43,150 | 0 |
| Administrative and General | 4,331,601 | 4,361,601 | 30,000 | 4,361,601 | 0 |
| Property Taxes | 103,000 | 103,000 | 0 | 103,000 | 0 |
| **Total** | **10,544,723** | **10,574,723** | **30,000** | **10,574,723** | **0** |
| | | | | | |
| Cost of Power | 62,242,349 | 64,439,405 | 2,197,056 | 64,439,405 | 0 |
| | | | | | |
| Working Capital Base | 72,787,072 | 75,014,128 | 2,227,056 | 74,845,128 | (169,000) |
| | | | | | |
| Working Capital Allowance (%) | 7.5% | 7.5% | 0% | 7.5% | 0% |
| | | | | | |
| **Working Capital Allowance ($)** | **5,459,030** | **5,626,060** | **167,029** | **5,613,385** | **(12,675)** |

#### Evidence References

- Ex.2/Tab 1/Sch.4-7 – Allowance for Working Capital

#### IR Responses

- 1-Staff-17
- 3-VECC-18
- 4-Energy Probe-15

#### Technical Conference Undertakings

- None

## Supporting Parties

All

## 2.1.4 Depreciation

### Complete Settlement

The parties accept that the updated forecast of depreciation/amortization expenses are appropriate.

Table 9: Depreciation

| Description | Application (A) | IR/TC Responses (B) | Variance (C) = (B) - (A) | Settlement (D) | Variance (E) = (D) - (B) |
|---|---|---|---|---|---|
| Depreciation | 4,766,330 | 4,724,996 | (41,334) | 4,724,996 | 0 |

### Evidence References

- Ex.4/Tab 11 – Depreciation/Amortization/Depletion

### IR Responses

- 2-Staff-19
- 2-Staff-21
- 2-Energy Probe-5
- 4-Staff-83
- 4-Energy Probe-17

### Technical Conference Undertakings

- JTC1.9

### Supporting Parties

All

## 2.1.5 Taxes

### Complete Settlement

The Parties accept the evidence of CNPI that its forecast taxes as adjusted are appropriate and have been correctly determined in accordance with OEB accounting policies and practices, subject to any adjustments for components of the calculation that are proceeding to hearing.

A summary of the adjusted Taxes is presented in Table 10 below.

Table 10: Income Taxes

| Description | Application (A) | IR/TC Responses (B) | Variance (C) = (B) - (A) | Settlement (D) | Variance (E) = (D) - (B) |
|---|---|---|---|---|---|
| Grossed-Up Income Taxes | 526,758 | 521,759 | (4,999) | 521,599 | (161) |

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

### Evidence References

- Ex. 4/Tab 12 – Income Taxes/Property Taxes
- CNPI Income Tax Model

### IR Responses

- 4-Staff-76 to 4-Staff-77

### Technical Conference Undertakings

- JTC1.1
- JTC1.3

### Supporting Parties

All

## 2.1.6 Other Revenue

### Complete Settlement

The Parties accept the evidence of CNPI that its proposed Other Revenues are appropriate and have been correctly determined in accordance with OEB accounting policies and practices, subject to an increase to the total forecast other revenue of $100,000 for the test year to more closely match the historical trend in Other Revenues.

### Table 11: Other Revenue

| Description | Application (A) | IR/TC Responses (B) | Variance (C) = (B) - (A) | Settlement (D) | Variance (E) = (D) - (B) |
|---|---|---|---|---|---|
| Specific Service Charges | 158,264 | 158,264 | 0 | 158,264 | 0 |
| Late Payment Charges | 354,100 | 354,100 | 0 | 354,100 | 0 |
| Other Revenue | 449,635 | 449,635 | 0 | 449,635 | 0 |
| Other Income of Deductions | 1,462,446 | 1,486,194 | 23,748 | 1,586,194 | 100,000 |
| **Total Revenue Offsets** | **2,424,445** | **2,448,193** | **23,748** | **2,548,193** | **100,000** |

### Evidence References

- Ex.3/Tab 1/Sch.1 – Overview of Operating Revenue
- Ex.3/Tab 4 – Other Distribution Revenue

### IR Responses

- 3-Staff-57
- 3-Energy Probe-11 to 3-Energy-Probe-13
- 3-VECC-23 to 3-VECC-24

### Technical Conference Undertakings

- JTC1.3
- JTC1.4

### Supporting Parties

All

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

### Complete Settlement

The Parties accept the evidence of CNPI that the proposed Base Revenue Requirement has been determined accurately, such that any changes to the components that make up the Base Revenue Requirement as a result of a Board Decision can be properly incorporated into an accurate redetermination of the Base Revenue Requirement.

# 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 Canadian Niagara Power's customers?

### Complete Settlement

The Parties accept the evidence of CNPI and its methodology used for the load forecast, customer forecast, loss factors and CDM adjustments, based on the updates resulting from CNPI's response to 3.0-VECC-18(c).

The resulting billing determinants are presented in Table 12 below.

### Table 12: 2017 Test Year Billing Determinants (for Cost Allocation and Rate Design)

| Rate Class | Customers / Connections | 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 | 26,074 | 198,077,803 | | 201,294,289 | | 3,216,486 | | 201,294,289 | | 0 | |
| GS < 50 | 2,489 | 67,907,332 | | 69,390,323 | | 1,482,991 | | 69,390,323 | | 0 | |
| GS > 50 | 217 | 184,944,203 | 593,383 | 190,144,345 | 610,067 | 5,200,142 | 16,684 | 190,144,345 | 610,067 | 0 | 0 |
| Embedded Distributor | 1 | 5,129,448 | 13,717 | 5,205,754 | 13,921 | 76,306 | 204 | 5,205,754 | 13,921 | 0 | 0 |
| Street Light | 5,713 | 2,781,556 | 8,591 | 2,991,556 | 9,240 | 210,000 | 649 | 2,991,556 | 9,240 | 0 | 0 |
| Sentinel Light | 695 | 629,014 | 1,916 | 629,014 | 1,916 | 0 | 0 | 629,014 | 1,916 | 0 | 0 |
| USL | 35 | 1,462,761 | | 1,462,761 | | 0 | | 1,462,761 | | 0 | |
| **Total** | **35,224** | **460,932,117** | **617,607** | **471,118,042** | **635,144** | **10,185,925** | **17,537** | **471,118,042** | **635,144** | **0** | **0** |

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

### Evidence References

- Ex.1/Tab 2/Sch.3 – Load Forecast Summary
- Ex.3/Tabs 1-3 – Load and Revenue Forecast, CDM Adjustments to Load Forecast, Accuracy of Load Forecast and Variance Analysis
- CNPI(Elenchus) 2017 Load Forecast Model

### IR Responses

- 3-VECC-17 to 3-VECC-22

## Technical Conference Undertakings

- JTC1.5

## Supporting Parties

All

### 3.1.1 Customer/Connection Forecast

The Parties accepted CNPI's 2017 Test year customer / connection forecast as proposed in the Application with no changes and summarized below:

Table 13: 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 | 26,074 | 26,074 | 0 | 26,074 | 0 |
| GS < 50 | 2,489 | 2,489 | 0 | 2,489 | 0 |
| GS > 50 | 217 | 217 | 0 | 217 | 0 |
| Embedded Distributor | 1 | 1 | 0 | 1 | 0 |
| Street Light | 5,713 | 5,713 | 0 | 5,713 | 0 |
| Sentinel Light | 695 | 695 | 0 | 695 | 0 |
| USL | 35 | 35 | 0 | 35 | 0 |
| **Total** | **35,224** | **35,224** | **0** | **35,224** | **0** |

Evidence References

- Ex.1/Tab 2/Sch.3 – Load Forecast Summary
- Ex.3/Tabs 1-3 – Load and Revenue Forecast, CDM Adjustments to Load Forecast, Accuracy of Load Forecast and Variance Analysis
- CNPI(Elenchus) 2017 Load Forecast Model

IR Responses

- 3-Energy Probe-10

Technical Conference Undertakings

- None

Supporting Parties

All

## 3.1.2 Load Forecast

The Parties agreed to the following updates in the Load Forecast Model:

- Re-evaluation of CDM persistence, corresponding adjustment to the Trend variable, and updates to employment forecasts as outlined in CNPI's response to 3.0-VECC-18(c)

Table 14 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 14: Summary of Load Forecast Billed kWh (CDM Adjusted)

| Rate Class | Customers / Connections | 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 | 26,074 | 198,077,803 | | 201,294,289 | | 3,216,486 | | 201,294,289 | | 0 | |
| GS < 50 | 2,489 | 67,907,332 | | 69,390,323 | | 1,482,991 | | 69,390,323 | | 0 | |
| GS > 50 | 217 | 184,944,203 | 593,383 | 190,144,345 | 610,067 | 5,200,142 | 16,684 | 190,144,345 | 610,067 | 0 | 0 |
| Embedded Distributor | 1 | 5,129,448 | 13,717 | 5,205,754 | 13,921 | 76,306 | 204 | 5,205,754 | 13,921 | 0 | 0 |
| Street Light | 5,713 | 2,781,556 | 8,591 | 2,991,556 | 9,240 | 210,000 | 649 | 2,991,556 | 9,240 | 0 | 0 |
| Sentinel Light | 695 | 629,014 | 1,916 | 629,014 | 1,916 | 0 | 0 | 629,014 | 1,916 | 0 | 0 |
| USL | 35 | 1,462,761 | | 1,462,761 | | 0 | | 1,462,761 | | 0 | |
| **Total** | **35,224** | **460,932,117** | **617,607** | **471,118,042** | **635,144** | **10,185,925** | **17,537** | **471,118,042** | **635,144** | **0** | **0** |

### Evidence References

- Ex.1/Tab 2/Sch.3 – Load Forecast Summary
- Ex.3/Tabs 1-3 – Load and Revenue Forecast, CDM Adjustments to Load Forecast, Accuracy of Load Forecast and Variance Analysis
- CNPI(Elenchus) 2017 Load Forecast Model

### IR Responses

- 3-VECC-17 to 3-VECC-22

### Technical Conference Undertakings

- JTC1.5

### Supporting Parties

All

## 3.1.1 Loss Factors

### Complete Settlement

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

Table 15: Loss Factors

| Description | 2017 Proposed |
|---|---|
| Total Loss Factor – Secondary Metered Customer <5,000kW | 1.0530 |
| Total Loss Factor – Primary Metered Customer <5,000kW | 1.0425 |

### Evidence References

- Ex.8/Tab 1/Sch.8 – Loss Adjustment Factors

### IR Responses

- None

### Technical Conference Undertakings

- None

### Supporting Parties

All

## 3.1.2 LRAMVA Baseline

### Complete Settlement

The Parties agree to the LRAMVA baseline for 2017 (and persisting until CNPI's next Cost of Service proceeding) as proposed in CNPI's response to 3.0-VECC-18(c) and presented in Table 16 below.

Table 16: LRAMVA Baseline kWhs and kWs

| Rate Class | 2017 kWh Pre-CDM Adjustment | Share | LRAMVA Baseline kWh | LRAMVA Baseline kW |
|---|---|---|---|---|
| Residential | 202,582,789 | 14.02% | 1,648,000 | |
| GS < 50 | 70,434,323 | 11.16% | 1,312,000 | |
| GS > 50 | 196,138,345 | 67.91% | 7,981,000 | 25,607 |
| Street Light | 3,720,056 | 6.90% | 811,000 | 2,505 |
| **Total** | **472,875,514** | **100.00%** | **11,752,000** | **28,111** |

### Evidence References

- Ex.3/Tab 1/Sch.2/App.A – 2016-2017 Weather Normalized Load Forecast – Elenchus Report
- CNPI(Elenchus) 2017 Load Forecast Model
- Ex.3/Tab 2/Sch.1 – CDM Adjustments to Load Forecast

### IR Responses

- 3-VECC-17 to 3-VECC-22

### Technical Conference Undertakings

- None

### Supporting Parties

All

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

### Complete Settlement

The Parties accept the evidence of CNPI that, subject to the adjustments identified below, the cost allocation methodology, allocations and revenue-to-cost ratios are appropriate.

CNPI agrees to reset the newly created Embedded Distributor Class to a revenue to cost ratio of 100%. CNPI updated its Cost Allocation Model to reflect all changes up to Partial Settlement, set the Embedded Distributor Class revenue to cost ratio to 100%, and then re-balanced its revenue requirement across classes by bringing the Streetlight revenue to cost ratio to the 120% ceiling of the Board's policy range and increasing both the Residential and USL ratios until the revenue requirement balanced.

### Table 17: 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 | 95.37% | 94.84% | (0.53%) | 94.85% | 0.01% |
| GS < 50 | 109.22% | 109.56% | 0.34% | 109.49% | (0.07%) |
| GS > 50 | 106.96% | 108.32% | 1.36% | 108.19% | (0.13%) |
| Embedded Distributor | 95.37% | 94.84% | (0.53%) | 100.00% | 5.16% |
| Street Light | 120.00% | 120.00% | 0.00% | 120.00% | 0.00% |
| Sentinel Light | 105.08% | 104.46% | (0.62%) | 104.35% | (0.11%) |
| USL | 95.37% | 94.84% | (0.53%) | 94.85% | 0.01% |

Methodology and target for Embedded Distributor class settled
Final results subject to change based on update of placeholder values for unsettled items in the Cost Allocation model

The Parties accept the evidence of CNPI 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 7
- 2017 Test Year Cost Allocation Model

### IR Responses

- 7-Staff-85
- 7-Energy Probe-20
- 7-VECC-33 to 7-VECC-36

### Technical Conference Undertakings

- JTC1.12

Supporting Parties

All

## 3.3 Are Canadian Niagara Power's proposals for rate design appropriate?

### Complete Settlement

The Parties accept the evidence of CNPI that all elements of the rate design have been correctly determined in accordance with OEB policies and practices. Table 18 shows the rates that result from the Application as adjusted by the interrogatory and technical conference responses and the settled issues in this Proposal, with those rates being subject to further adjustments based on the results of the hearing of the unsettled issues.

Table 18: January 1, 2017 Distribution Rates

| Rate Class | Fixed Rate | Billing Determinant | Variable Rate | Fixed % | Variable % |
|---|---|---|---|---|---|
| Residential | $ 29.45 | kWh | $ 0.0112 | 80.37% | 19.63% |
| GS < 50 | $ 30.92 | kWh | $ 0.0252 | 34.59% | 65.41% |
| GS > 50 | $ 166.12 | kW | $ 7.2864 | 9.26% | 90.74% |
| Embedded Distributor | $ 604.27 | kW | $ 8.3238 | 5.89% | 94.11% |
| Street Light | $ 3.97 | kW | $ 8.6511 | 77.32% | 22.68% |
| Sentinel Light | $ 5.57 | kW | $ 6.4563 | 78.97% | 21.03% |
| USL | $ 48.32 | kWh | $ 0.0262 | 34.58% | 65.42% |

Methodology settled
Final rates subject to change based on update of placeholder values for unsettled items in the Rate Design model

### Evidence References

- Exhibit 8
- 2017 Test Year Rate Design Model

### IR Responses

- 8-VECC-37 to 8-VECC-38

### Technical Conference Undertakings

- None

### Supporting Parties

All

## 3.3.1 Residential Rate Design

### Complete Settlement

The Parties accept that CNPI's proposal to move to a fully fixed monthly charge by 2020 is in accordance with OEB policies, subject to any adjustments that flow from the decision on unsettled issues.

### Evidence References

- Ex.8/Tab 1/Sch.1 – Rate Design Overview
- 2017 Test Year Rate Design Model

### IR Responses

- None

### Technical Conference Undertakings

- None

### Supporting Parties

CNPI, VECC, ENERGY PROBE

### Parties Taking No Position

SEC

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

### Complete Settlement

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

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

### 3.4.1 Low Voltage Service Rates

#### Complete Settlement

The Parties have agreed to the Low Voltage rates presented in Table 19 below.

Table 19: Low Voltage Service Rates

| Rate Class | % Allocation | Charges | Volume | Rate | Determinant |
|---|---|---|---|---|---|
| Residential | 42.1% | $ 59,743.43 | 211,962,886 | $ 0.0003 | kWh |
| GS < 50 | 12.5% | $ 17,754.14 | 73,068,010 | $ 0.0002 | kWh |
| GS > 50 | 43.5% | $ 61,674.53 | 610,067 | $ 0.1011 | kW |
| Embedded Distributor | 1.0% | $ 1,407.34 | 13,921 | $ 0.1011 | kW |
| Street Light | 0.5% | $ 712.74 | 9,240 | $ 0.0771 | kW |
| Sentinel Light | 0.1% | $ 158.07 | 1,916 | $ 0.0825 | kW |
| USL | 0.3% | $ 381.75 | 1,540,287 | $ 0.0002 | kWh |
| **Total** | **100.0%** | **$ 141,832.00** | **285,666,040** | | |

#### Evidence References

- Ex.8/Tab 1/Sch.7 – Low Voltage Service Charges

#### IR Responses

- 8-VECC-38

#### Technical Conference Undertakings

- None

#### Supporting Parties

All

## 3.4.2 Retail Transmission Service Rates

### Complete Settlement

The Parties have agreed to the RTSR rates presented in Table 20 below. An updated copy of the OEB's RTSR model has been submitted in live Excel format as part of this settlement proposal.

Table 20: RTSR Network and Connection Rates

| Rate Class | Billing Determinant | Proposed Network | Proposed Connection |
|---|---|---|---|
| Residential | kWh | $ 0.0067 | $ 0.0057 |
| GS < 50 | kWh | $ 0.0057 | $ 0.0049 |
| GS > 50 | kW | $ 2.4230 | $ 2.0556 |
| Embedded Distributor | kW | $ 2.4230 | $ 2.0556 |
| Street Light | kW | $ 1.7934 | $ 1.5684 |
| Sentinel Light | kW | $ 2.0649 | $ 1.6775 |
| USL | kWh | $ 0.0060 | $ 0.0050 |

### Evidence References

- Ex.8/Tab 1/Sch.2 – Retail Transmission Service Rates
- RTSR Workform

### IR Responses

- Updated RTSR Workform

### Technical Conference Undertakings

- None

### Supporting Parties

All

# 4 ACCOUNTING

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

### Partial Settlement

The Parties accept the evidence of CNPI 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, with the exception of the manner in which Pension and OPEB costs have been accounted for in rates.

CNPI has incorporated Pension and OPEB costs into rates on an accrual accounting basis; one or more intervenors may explore at the hearing the appropriateness of including Pension and/or OPEB costs in rates on a cash accounting basis, an accounting change that would impact the revenue requirement for the test period.  CNPI notes that the issue of the appropriate regulatory treatment of Pensions and OPEB costs is currently being fully reviewed by the Ontario Energy Board in consultation EB-2015-0040 "Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs", such that in CNPI's view it would be premature to decide that issue in this case prior to the Board's determination of the issue for the all LDCs.

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

- Ex.1/Tab 4/Sch.1 – Accounting Standard

### IR Responses

- None

### Technical Conference Undertakings

- None

### Supporting Parties

All

## 4.2 Are Canadian Niagara Power'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?

### Partial Settlement

With three exceptions, detailed below, the Parties accept the evidence of CNPI that all elements of the applied for deferral and variance accounts are appropriate, including the balances in the existing accounts and their disposition on a harmonized basis commencing January 1, 2017 and the continuation of existing accounts.

Table 21 below summarizes the amounts for disposition and associated rate riders by rate class.

Table 21: DVA and LRAMVA Rate Riders

| Rate Class | Billing Determinant | Disposition of DVA's (2017) & MIST/Stranded Meters | | |
|---|---|---|---|---|
| | | $/kWh | $/kW | $/month/customer |
| Residential | kWh | -$ 0.0033 | | -$ 0.1500 |
| GS < 50 | kWh | -$ 0.0035 | | |
| GS > 50 | kW | | -$ 1.1120 | $ 10.6500 |
| Embedded Distributor | kW | | -$ 1.3389 | |
| Street Light | kW | | -$ 1.1592 | |
| Sentinel Light | kW | | -$ 1.1754 | |
| USL | kWh | -$ 0.0036 | | |

| Rate Class | Disposition of DVA's (2017) - Applicable to Non-RPP Only ($/kWh) |
|---|---|
| Residential | $ 0.0066 |
| GS < 50 | $ 0.0066 |
| GS > 50 | $ 0.0066 |
| GS > 50 - Class A | $ 0.0023 |
| Embedded Distributor | $ 0.0066 |
| Street Light | $ 0.0066 |
| USL | $ 0.0066 |

| Rate Class | Billing Determinant | Disposition of LRAMVA | |
|---|---|---|---|
| | | $/kWh | $/kW |
| Residential | kWh | $ 0.0006 | |
| GS < 50 | kWh | $ 0.0023 | |
| GS > 50 | kW | | $ 0.1687 |

In connection with the unsettled issue concerning the proper accounting treatment of Pension and OPEB related OM&A costs, parties may make submissions in support of a new variance account related to Pension and OPEB costs, such that issue 4.2 remains unsettled to account for the possibility of that new variance account as a result of the resolution of the unsettled issue.

The Parties note that the likelihood of the Board releasing a decision on the unsettled issues prior to the proposed January 1, 2017 implementation date for all proposed rates is unlikely. CNPI in its application requested an order making its current rates interim as of January 1, 2017. The Parties acknowledge that the DVA and LRAMVA rate riders may be impacted as a result of an implementation date other than January 1, 2017.

In connection with the unsettled issue concerning the cost of long-term debt, some parties may take the position that a variance account should be established to capture some or all changes in the cost of long-term debt.

Evidence References
- Ex.1/Tab 2/Sch.8 – Deferral and Variance Accounts
- Exhibit 9
- 2017 Test Year EDDVAR Continuity Schedule

IR Responses
- 4-Staff-66 to 4-Staff-75
- 4-VECC-31
- 9-Staff-86 to 9-Staff-88
- 9-Energy Probe-21
- 9-VECC-39

Technical Conference Undertakings
- JTC1.6
- JTC1.7
- JTC1.10

Supporting Parties
All

### 4.2.1 Effective Date

#### No Settlement

The Parties note that the likelihood of the Board releasing a decision on the unsettled issues prior to the proposed January 1, 2017 implementation date for all proposed rates is unlikely. CNPI in its application requested an order making its current rates interim as of January 1, 2017. The issue of the appropriateness of a January 1, 2017 effective date for rates remains an unsettled issue.

#### Evidence References

- Ex.1/Tab 6/Sch.1 – The Application
- Ex.1/Tab 6/Sch.9 – List of Approvals Requested

#### IR Responses

- None

#### Technical Conference Undertakings\

- None

#### Supporting Parties

All

# 5 ATTACHMENTS

| | |
|---|---|
| Attachment A | Revenue Requirement Workform |
| | |
| Attachment B | 2016 and 2017 Fixed Asset Continuity Schedule |
| | |

# Attachment A – Revenue Requirement Workform

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

**Version** 7.02

| | |
|---|---|
| **Utility Name** | Canadian Niagara Power Inc. |
| **Service Territory** | |
| **Assigned EB Number** | EB-2016-0061 |
| **Name and Title** | Brian Vander Vloet, Manager Regulatory Accountin |
| **Phone Number** | 905-871-0330 ext 3208 |
| **Email Address** | brian.vandervloet@cnpower.com |

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.



***While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.***

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers



**Notes:**

| | |
|---|---|
| **(1)** | Pale green cells represent inputs |
| **(2)** | Pale green boxes at the bottom of each page are for additional notes |
| **(3)** | Pale yellow cells represent drop-down lists |
| **(4)** | ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.*** |
| **(5)** | ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.*** |

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

## Data Input [1]

| | | Initial Application | (2) | Adjustments | | Settlement Agreement | (6) | Adjustments | Per Board Decision | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Rate Base** | | | | | | | | | |
| | Gross Fixed Assets (average) | $147,209,031 | | ($483,000) | ### | $ 146,726,031 | | | $146,726,031 | |
| | Accumulated Depreciation (average) | ($62,743,580) | (5) | $41,334 | ### | ($62,702,246) | | | ($62,702,246) | |
| | Allowance for Working Capital: | | | | | | | | | |
| | Controllable Expenses | $10,544,723 | | ($139,000) | ### | $ 10,405,723 | | | $10,405,723 | |
| | Cost of Power | $62,242,349 | | $2,366,056 | ### | $ 64,608,405 | | | $64,608,405 | |
| | Working Capital Rate (%) | 7.50% | (9) | | | 7.50% | (9) | | 7.50% | (9) |
| 2 | **Utility Income** | | | | | | | | | |
| | Operating Revenues: | | | | | | | | | |
| | Distribution Revenue at Current Rates | $17,535,614 | | $197,351 | | $17,732,965 | ### | $0 | $17,732,965 | |
| | Distribution Revenue at Proposed Rates | $19,870,307 | | ($468,715) | | $19,401,592 | ### | $0 | $19,401,592 | |
| | Other Revenue: | | | | | | | | | |
| | Specific Service Charges | $158,264 | | $0 | | $158,264 | | $0 | $158,264 | |
| | Late Payment Charges | $354,100 | | $0 | | $354,100 | | $0 | $354,100 | |
| | Other Distribution Revenue | $449,635 | | $0 | | $449,635 | | $0 | $449,635 | |
| | Other Income and Deductions | $1,462,446 | | $123,748 | | $1,586,194 | ### | $0 | $1,586,194 | |
| | Total Revenue Offsets | $2,424,445 | (7) | $123,748 | | $2,548,193 | ### | $0 | $2,548,193 | |
| | Operating Expenses: | | | | | | | | | |
| | OM+A Expenses | $10,441,723 | | $30,000 | ### | $ 10,471,723 | | $ - | $10,471,723 | |
| | Depreciation/Amortization | $4,766,330 | | ($41,334) | ### | $ 4,724,996 | | $ - | $4,724,996 | |
| | Property taxes | $103,000 | | $ - | | $ 103,000 | | $ - | $103,000 | |
| | Other expenses | | | | | | | | | |
| 3 | **Taxes/PILs** | | | | | | | | | |
| | Taxable Income: | | | | | | | | | |
| | Adjustments required to arrive at taxable income | ($1,844,756) | (3) | | | ($1,651,012) | ### | | ($1,651,012) | |
| | Utility Income Taxes and Rates: | | | | | | | | | |
| | Income taxes (not grossed up) | $387,167 | | | | $383,375 | | | $383,375 | |
| | Income taxes (grossed up) | $526,758 | | | | $521,599 | | | $521,599 | |
| | Federal tax (%) | 15.00% | | | | 15.00% | | | 15.00% | |
| | Provincial tax (%) | 11.50% | | | | 11.50% | | | 11.50% | |
| | Income Tax Credits | ($13,460) | | | | ($13,460) | | | ($13,460) | |
| 4 | **Capitalization/Cost of Capital** | | | | | | | | | |
| | Capital Structure: | | | | | | | | | |
| | Long-term debt Capitalization Ratio (%) | 56.0% | | | | 56.0% | | | 56.0% | |
| | Short-term debt Capitalization Ratio (%) | 4.0% | (8) | | | 4.0% | (8) | | 4.0% | (8) |
| | Common Equity Capitalization Ratio (%) | 40.0% | | | | 40.0% | | | 40.0% | |
| | Prefered Shares Capitalization Ratio (%) | | | | | | | | | |
| | | 100.0% | | | | 100.0% | | | 100.0% | |
| | Cost of Capital | | | | | | | | | |
| | Long-term debt Cost Rate (%) | 6.14% | | | | 5.81% | ### | | 5.81% | |
| | Short-term debt Cost Rate (%) | 1.65% | | | | 1.76% | ### | | 1.76% | |
| | Common Equity Cost Rate (%) | 9.19% | | | | 8.78% | ### | | 8.78% | |
| | Prefered Shares Cost Rate (%) | | | | | | | | | |

**Notes:**

**General** Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

(10) See 2-Energy Probe-5. Reduction in 2016 capitalized expenditures of $483k and corresponding depreciation expense and CCA adjustments.
(11) See 1-Staff-17. Increase relates to $30k Letter of Credit fees; -$169k WCA adjustment for vehicle depreciation included in OM&A per Settlement.
(12) COP adjustment based 3.0-VECC-18 (load forecast and other price updates)
(13) +$30k per 3.0-VECC-23 (Interest and Dividend Income); Offset $6k adjustment related to JTC 1.3 (OEB 4375 revenue decrease); +$100k per Settlement
(14) Adjustment based on load forecast update as per 3.0-VECC-18.
(15) Decrease in total revenue required at proposed rates resulting from the net impact of all adjustments required based on IR and TC responses and partial settlement.
(16) JTC 1.1. Cost of capital update per OEB release on Oct 27, 2016.

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

## Rate Base and Working Capital

### Rate Base

| Line No. | Particulars | | Initial Application | Adjustments | | Settlement Agreement | Adjustments | Per Board Decision |
|---|---|---|---|---|---|---|---|---|
| 1 | Gross Fixed Assets (average) | (2) | $147,209,031 | ($483,000) | (3) | $146,726,031 | $ - | $146,726,031 |
| 2 | Accumulated Depreciation (average) | (2) | ($62,743,580) | $41,334 | (3) | ($62,702,246) | $ - | ($62,702,246) |
| 3 | Net Fixed Assets (average) | (2) | $84,465,451 | ($441,666) | | $84,023,785 | $ - | $84,023,785 |
| 4 | Allowance for Working Capital | (1) | $5,459,030 | $167,029 | | $5,626,060 | $ - | $5,626,060 |
| 5 | **Total Rate Base** | | $89,924,481 | ($274,637) | | $89,649,845 | $ - | $89,649,845 |

(1) **Allowance for Working Capital - Derivation**

| Line No. | Particulars | | Initial Application | Adjustments | | Settlement Agreement | Adjustments | Per Board Decision |
|---|---|---|---|---|---|---|---|---|
| 6 | Controllable Expenses | | $10,544,723 | ($139,000) | (4) | $10,405,723 | $ - | $10,405,723 |
| 7 | Cost of Power | | $62,242,349 | $2,366,056 | (5) | $64,608,405 | $ - | $64,608,405 |
| 8 | Working Capital Base | | $72,787,072 | $2,227,056 | | $75,014,128 | $ - | $75,014,128 |
| 9 | Working Capital Rate % | (1) | 7.50% | 0.00% | | 7.50% | 0.00% | 7.50% |
| 10 | Working Capital Allowance | | $5,459,030 | $167,029 | | $5,626,060 | $ - | $5,626,060 |

**Notes**

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2017 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

(3) See 2-Energy Probe-5. Reduction in 2016 capitalized expenditures of $483k and corresponding depreciation expense adjustments.

(4) See 1-Staff-17. Increase relates to $30k Letter of Credit fees. -$169k WCA adjustment for vehicle depreciation included in OM&A per Settlement.

(5) COP adjustment based 3.0-VECC-18 (load forecast and other price updates).

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

## Utility Income

| Line No. | Particulars | | Initial Application | Adjustments | | Settlement Agreement | Adjustments | Per Board Decision |
|---|---|---|---|---|---|---|---|---|
| | **Operating Revenues:** | | | | | | | |
| 1 | Distribution Revenue (at Proposed Rates) | | $19,870,307 | ($468,715) | ## | $19,401,592 | $ - | $19,401,592 |
| 2 | Other Revenue | (1) | $2,424,445 | $123,748 | ## | $2,548,193 | $ - | $2,548,193 |
| 3 | Total Operating Revenues | | $22,294,752 | ($344,967) | | $21,949,785 | $ - | $21,949,785 |
| | **Operating Expenses:** | | | | | | | |
| 4 | OM+A Expenses | | $10,441,723 | $30,000 | ## | $10,471,723 | $ - | $10,471,723 |
| 5 | Depreciation/Amortization | | $4,766,330 | ($41,334) | ## | $4,724,996 | $ - | $4,724,996 |
| 6 | Property taxes | | $103,000 | $ - | | $103,000 | $ - | $103,000 |
| 7 | Capital taxes | | $ - | $ - | | $ - | $ - | $ - |
| 8 | Other expense | | $ - | $ - | | | $ - | |
| 9 | Subtotal (lines 4 to 8) | | $15,311,053 | ($11,334) | | $15,299,719 | $ - | $15,299,719 |
| 10 | Deemed Interest Expense | | $3,151,314 | ($171,353) | | $2,979,961 | $ - | $2,979,961 |
| 11 | Total Expenses (lines 9 to 10) | | $18,462,367 | ($182,687) | | $18,279,680 | $ - | $18,279,680 |
| 12 | **Utility income before income taxes** | | $3,832,385 | ($162,280) | | $3,670,105 | $ - | $3,670,105 |
| 13 | Income taxes (grossed-up) | | $526,758 | ($5,159) | | $521,599 | $ - | $521,599 |
| 14 | **Utility net income** | | $3,305,628 | ($157,121) | | $3,148,507 | $ - | $3,148,507 |

**Notes**

### Other Revenues / Revenue Offsets

| Note | Particulars | Initial Application | Adjustments | | Settlement Agreement | Adjustments | Per Board Decision |
|---|---|---|---|---|---|---|---|
| (1) | Specific Service Charges | $158,264 | $ - | | $158,264 | $ - | $158,264 |
| | Late Payment Charges | $354,100 | $ - | | $354,100 | $ - | $354,100 |
| | Other Distribution Revenue | $449,635 | $ - | | $449,635 | $ - | $449,635 |
| | Other Income and Deductions | $1,462,446 | $123,748 | ## | $1,586,194 | $ - | $1,586,194 |
| | Total Revenue Offsets | $2,424,445 | $123,748 | | $2,548,193 | $ - | $2,548,193 |

(1) Decrease in total revenue required at proposed rates resulting from the net impact of all adjustments required based on IR and TC responses.
(2) $30k adjustment based on 3.0-VECC-23. Increase relates to Interest and Dividend Income. Offset $6k adjustment related to JTC 1.3. Decrease relates to
(3) See 1-Staff-17. Increase relates to $30k Letter of Credit fees.
(4) See 2-Energy Probe-5. Reduction in 2016 capitalized expenditures of $483k and corresponding depreciation expense adjustments.

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

## Taxes/PILs

| Line No. | Particulars | Application | | Settlement Agreement | | Per Board Decision |
|---|---|---|---|---|---|---|
| | **Determination of Taxable Income** | | | | | |
| 1 | Utility net income before taxes | $3,305,624 | | $3,148,503 | | $3,148,503 |
| 2 | Adjustments required to arrive at taxable utility income | ($1,844,756) | | ($1,651,012) | (1) | ($1,651,012) |
| 3 | Taxable income | $1,460,868 | | $1,497,491 | | $1,497,491 |
| | **Calculation of Utility income Taxes** | | | | | |
| 4 | Income taxes | $387,167 | | $383,375 | (1) | $383,375 |
| 6 | Total taxes | $387,167 | | $383,375 | | $383,375 |
| 7 | Gross-up of Income Taxes | $139,591 | | $138,224 | | $138,224 |
| 8 | Grossed-up Income Taxes | $526,758 | | $521,599 | | $521,599 |
| 9 | PILs / tax Allowance (Grossed-up Income taxes + Capital taxes) | $526,758 | | $521,599 | | $521,599 |
| 10 | Other tax Credits | ($13,460) | | ($13,460) | | ($13,460) |
| | **Tax Rates** | | | | | |
| 11 | Federal tax (%) | 15.00% | | 15.00% | | 15.00% |
| 12 | Provincial tax (%) | 11.50% | | 11.50% | | 11.50% |
| 13 | Total tax rate (%) | 26.50% | | 26.50% | | 26.50% |

**Notes**

**(1)** Changes are due to cumulative impact of all adjustments required based on IR and TC responses and partial settlement.

# Revenue Requirement Workform (RRWF) for 2017 Filers

## Capitalization/Cost of Capital

| Line No. | Particulars | Capitalization Ratio | | Cost Rate | | Return |
|---|---|---|---|---|---|---|
| | | **Initial Application** | | | | |
| | | (%) | ($) | (%) | | ($) |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | $50,357,710 | 6.14% | | $3,091,963 |
| 2 | Short-term Debt | 4.00% | $3,596,979 | 1.65% | | $59,350 |
| 3 | **Total Debt** | 60.00% | $53,954,689 | 5.84% | | $3,151,314 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | $35,969,793 | 9.19% | | $3,305,624 |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | | $ - |
| 6 | **Total Equity** | 40.00% | $35,969,793 | 9.19% | | $3,305,624 |
| 7 | **Total** | 100.00% | $89,924,481 | 7.18% | | $6,456,937 |
| | | **Settlement Agreement** | | | | |
| | | (%) | ($) | (%) | | ($) |
| | **Debt** | | | | | |
| 1 | Long-term Debt | 56.00% | $50,203,913 | 5.81% | (1) | $2,916,847 |
| 2 | Short-term Debt | 4.00% | $3,585,994 | 1.76% | (1) | $63,113 |
| 3 | **Total Debt** | 60.00% | $53,789,907 | 5.54% | | $2,979,961 |
| | **Equity** | | | | | |
| 4 | Common Equity | 40.00% | $35,859,938 | 8.78% | (1) | $3,148,503 |
| 5 | Preferred Shares | 0.00% | $ - | 0.00% | | $ - |
| 6 | **Total Equity** | 40.00% | $35,859,938 | 8.78% | | $3,148,503 |
| 7 | **Total** | 100.00% | $89,649,845 | 6.84% | | $6,128,463 |
| | | **Per Board Decision** | | | | |
| | | (%) | ($) | (%) | | ($) |
| | **Debt** | | | | | |
| 8 | Long-term Debt | 56.00% | $50,203,913 | 5.81% | | $2,916,847 |
| 9 | Short-term Debt | 4.00% | $3,585,994 | 1.76% | | $63,113 |
| 10 | **Total Debt** | 60.00% | $53,789,907 | 5.54% | | $2,979,961 |
| | **Equity** | | | | | |
| 11 | Common Equity | 40.00% | $35,859,938 | 8.78% | | $3,148,503 |
| 12 | Preferred Shares | 0.00% | $ - | 0.00% | | $ - |
| 13 | **Total Equity** | 40.00% | $35,859,938 | 8.78% | | $3,148,503 |
| 14 | **Total** | 100.00% | $89,649,845 | 6.84% | | $6,128,463 |

**Notes**

(1) Cost of capital rate changes per JTC 1.1. Additional changes in $ amounts due to cumulative impact of adjustments required based on IR and TC responses, and partial settlement. See Tab 14 for details.

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

## Revenue Deficiency/Sufficiency

| Line No. | Particulars | Initial Application: At Current Approved Rates | Initial Application: At Proposed Rates | Settlement Agreement: At Current Approved Rates | Settlement Agreement: At Proposed Rates | Per Board Decision: At Current Approved Rates | Per Board Decision: At Proposed Rates |
|---|---|---|---|---|---|---|---|
| 1 | Revenue Deficiency from Below | | $2,441,458 | | $1,668,623 | | $1,668,623 |
| 2 | Distribution Revenue | $17,535,614 | $17,428,849 | $17,732,965 | $17,732,969 | $17,732,965 | $17,732,969 |
| 3 | Other Operating Revenue Offsets - net | $2,424,445 | $2,424,445 | $2,548,193 | $2,548,193 | $2,548,193 | $2,548,193 |
| 4 | **Total Revenue** | $19,960,059 | $22,294,752 | $20,281,158 | $21,949,785 | $20,281,158 | $21,949,785 |
| 5 | Operating Expenses | $15,311,053 | $15,311,053 | $15,299,719 | $15,299,719 | $15,299,719 | $15,299,719 |
| 6 | Deemed Interest Expense | $3,151,314 | $3,151,314 | $2,979,961 | $2,979,961 | $2,979,961 | $2,979,961 |
| 8 | **Total Cost and Expenses** | $18,462,367 | $18,462,367 | $18,279,680 | $18,279,680 | $18,279,680 | $18,279,680 |
| 9 | **Utility Income Before Income Taxes** | $1,497,692 | $3,832,385 | $2,001,478 | $3,670,105 | $2,001,478 | $3,670,105 |
| 10 | Tax Adjustments to Accounting Income per 2013 PILs model | ($1,844,756) | ($1,844,756) | ($1,651,012) | ($1,651,012) | ($1,651,012) | ($1,651,012) |
| 11 | **Taxable Income** | ($347,064) | $1,987,629 | $350,466 | $2,019,093 | $350,466 | $2,019,093 |
| 12 | Income Tax Rate | 26.50% | 26.50% | 26.50% | 26.50% | 26.50% | 26.50% |
| 13 | **Income Tax on Taxable Income** | $ - | $526,722 | $92,874 | $535,060 | $92,874 | $535,060 |
| 14 | **Income Tax Credits** | ($13,460) | ($13,460) | ($13,460) | ($13,460) | ($13,460) | ($13,460) |
| 15 | **Utility Net Income** | $1,511,152 | $3,305,628 | $1,922,065 | $3,148,507 | $1,922,065 | $3,148,507 |
| 16 | **Utility Rate Base** | $89,924,481 | $89,924,481 | $89,649,845 | $89,649,845 | $89,649,845 | $89,649,845 |
| 17 | Deemed Equity Portion of Rate Base | $35,969,793 | $35,969,793 | $35,859,938 | $35,859,938 | $35,859,938 | $35,859,938 |
| 18 | Income/(Equity Portion of Rate Base) | 4.20% | 9.19% | 5.36% | 8.78% | 5.36% | 8.78% |
| 19 | Target Return - Equity on Rate Base | 9.19% | 9.19% | 8.78% | 8.78% | 8.78% | 8.78% |
| 20 | Deficiency/Sufficiency in Return on Equity | -4.99% | 0.00% | -3.42% | 0.00% | -3.42% | 0.00% |
| 21 | Indicated Rate of Return | 5.18% | 7.18% | 5.47% | 6.84% | 5.47% | 6.84% |
| 22 | Requested Rate of Return on Rate Base | 7.18% | 7.18% | 6.84% | 6.84% | 6.84% | 6.84% |
| 23 | Deficiency/Sufficiency in Rate of Return | -2.00% | 0.00% | -1.37% | 0.00% | -1.37% | 0.00% |
| 24 | Target Return on Equity | $3,305,624 | $3,305,624 | $3,148,503 | $3,148,503 | $3,148,503 | $3,148,503 |
| 25 | Revenue Deficiency/(Sufficiency) | $1,794,471 | $4 | $1,226,438 | $4 | $1,226,438 | $4 |
| 26 | **Gross Revenue Deficiency/(Sufficiency)** | $2,441,458 (1) | | $1,668,623 (1) | | $1,668,623 (1) | |

**Notes:**

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

## Revenue Requirement

| Line No. | Particulars | Application | | Settlement Agreement | | Per Board Decision | |
|---|---|---|---|---|---|---|---|
| 1 | OM&A Expenses | $10,441,723 | | $10,471,723 | (3) | $10,471,723 | |
| 2 | Amortization/Depreciation | $4,766,330 | | $4,724,996 | (4) | $4,724,996 | |
| 3 | Property Taxes | $103,000 | | $103,000 | | $103,000 | |
| 5 | Income Taxes (Grossed up) | $526,758 | | $521,599 | (5) | $521,599 | |
| 6 | Other Expenses | $ - | | | | | |
| 7 | Return | | | | | | |
| | Deemed Interest Expense | $3,151,314 | | $2,979,961 | (5) | $2,979,961 | |
| | Return on Deemed Equity | $3,305,624 | | $3,148,503 | (5) | $3,148,503 | |
| 8 | **Service Revenue Requirement (before Revenues)** | $22,294,748 | | $21,949,781 | (5) | $21,949,781 | |
| 9 | Revenue Offsets | $2,424,445 | | $2,548,193 | (6) | $2,548,193 | |
| 10 | **Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)** | $19,870,303 | | $19,401,588 | (5) | $19,401,588 | |
| 11 | Distribution revenue | $19,870,307 | | $19,401,592 | (5) | $19,401,592 | |
| 12 | Other revenue | $2,424,445 | | $2,548,193 | (6) | $2,548,193 | |
| 13 | **Total revenue** | $22,294,752 | | $21,949,785 | (5) | $21,949,785 | |
| 14 | **Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)** | $4 | (1) | $4 | (1) | $4 | (1) |

### Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

| | Application | Settlement Agreement | Δ% (2) | Per Board Decision | Δ% (2) |
|---|---|---|---|---|---|
| **Service Revenue Requirement** | $22,294,748 | $21,949,781 | ($0) | $21,949,781 | ($1) |
| **Grossed-Up Revenue Deficiency/(Sufficiency)** | $2,441,458 | $1,668,623 | ($0) | $1,668,623 | ($1) |
| | | | | | |
| **Base Revenue Requirement (to be recovered from Distribution Rates)** | $19,870,303 | $19,401,588 | ($0) | $19,401,588 | ($1) |
| **Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement** | $2,334,693 | $1,668,627 | ($0) | $1,668,627 | ($1) |

**Notes**

(1) Line 11 - Line 8
(2) Percentage Change Relative to Initial Application
(3) See 1-Staff-17. Increase relates to $30k Letter of Credit fees.
(4) See 2-Energy Probe-5. Reduction in 2016 capitalized expenditures of $483k and corresponding depreciation expense adjustments.
(5) Changes are due to cumulative impact of all adjustments required based on IR and TC responses and partial settlement. See Tab 14 for
(6) $30k adjustment based on 3.0-VECC-23. Increase relates to Interest and Dividend Income. Offset $6k adjustment related to JTC 1.3. +$100k per Settlement

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

## Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

**Appendix 2-IB** is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

**Stage in Process:** Settlement Agreement

| | Customer Class | Initial Application | | | Settlement Agreement | | | Per Board Decision | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Input the name of each customer class. | **Customer / Connections** Test Year average or mid-year | **kWh** Annual | **kW/kVA** (1) Annual | **Customer / Connections** Test Year average or mid-year | **kWh** Annual | **kW/kVA** (1) Annual | **Customer / Connections** Test Year average or mid-year | **kWh** Annual | **kW/kVA** (1) Annual |
| 1 | Residential | 26,074 | 198,077,803 | | 26,074 | 201,294,289 | | | | |
| 2 | GS < 50 | 2,489 | 67,907,332 | | 2,489 | 69,390,323 | | | | |
| 3 | GS > 50 | 217 | 184,944,203 | 593,383 | 217 | 190,144,345 | 610,067 | | | |
| 4 | Embedded Distributor | 1 | 5,129,448 | 13,717 | 1 | 5,205,754 | 13,921 | | | |
| 5 | Street Light | 5,713 | 2,781,556 | 8,591 | 5,713 | 2,991,556 | 9,240 | | | |
| 6 | Sentinel Light | 695 | 629,014 | 1,916 | 695 | 629,014 | 1,916 | | | |
| 7 | USL | 35 | 1,462,761 | | 35 | 1,462,761 | | | | |
| 8 | | | | | | | | | | |
| 9 | | | | | | | | | | |
| 10 | | | | | | | | | | |
| 11 | | | | | | | | | | |
| 12 | | | | | | | | | | |
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| 16 | | | | | | | | | | |
| 17 | | | | | | | | | | |
| 18 | | | | | | | | | | |
| 19 | | | | | | | | | | |
| 20 | | | | | | | | | | |
| | **Total** | | **460,932,117** | | | | | | | |

**Notes:**

(1) Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

## Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

**Stage in Application Process:** ***Settlement Agreement***

### A) *Allocated Costs*

| | Name of Customer Class [3] | Costs Allocated from Previous Study [1] | % | Allocated Class Revenue Requirement [1] (7A) | % |
|---|---|---|---|---|---|
| | From Sheet 10. Load Forecast | | | | |
| 1 | Residential | $ 11.876.815 | 62.62% | $ 13.857.162 | 63.13% |
| 2 | GS < 50 | $ 2.376.032 | 12.53% | $ 2.718.979 | 12.39% |
| 3 | GS > 50 | $ 4.090.319 | 21.57% | $ 4.783.667 | 21.79% |
| 4 | Embedded Distributor | | | $ 134.692 | 0.61% |
| 5 | Street Light | $ 503.635 | 2.66% | $ 323.227 | 1.47% |
| 6 | Sentinel Light | $ 82.426 | 0.43% | $ 62.797 | 0.29% |
| 7 | USL | $ 36.954 | 0.19% | $ 69.260 | 0.32% |
| 8 | | | | | |
| 9 | | | | | |
| 10 | | | | | |
| 11 | | | | | |
| 12 | | | | | |
| 13 | | | | | |
| 14 | | | | | |
| 15 | | | | | |
| 16 | | | | | |
| 17 | | | | | |
| 18 | | | | | |
| 19 | | | | | |
| 20 | | | | | |
| | **Total** | $ 18.966.181 | 100.00% | **$ 21.949.785** | 100.00% |
| | | | **Service Revenue Requirement (from Sheet 9)** | **$ 21,949,781.02** | |

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

### B) *Calculated Class Revenues*

| | Name of Customer Class | Load Forecast (LF) X current approved rates (7B) | LF X current approved rates X (1+d) (7C) | LF X Proposed Rates (7D) | Miscellaneous Revenues (7E) |
|---|---|---|---|---|---|
| 1 | Residential | $ 10.393.768 | $ 11.371.795 | $ 11.466.427 | $ 1.677.078 |
| 2 | GS < 50 | $ 2.440.047 | $ 2.669.649 | $ 2.669.649 | $ 307.463 |
| 3 | GS > 50 | $ 4.270.634 | $ 4.672.489 | $ 4.672.489 | $ 502.892 |
| 4 | Embedded Distributor | $ 94.935 | $ 103.869 | $ 123.127 | $ 11.565 |
| 5 | Street Light | $ 439.797 | $ 481.181 | $ 352.402 | $ 35.470 |
| 6 | Sentinel Light | $ 53.757 | $ 58.815 | $ 58.815 | $ 6.711 |
| 7 | USL | $ 40.027 | $ 43.793 | $ 58.682 | $ 7.013 |
| 8 | | | | | |
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| 18 | | | | | |
| 19 | | | | | |
| 20 | | | | | |
| | **Total** | $ 17.732.965 | $ 19.401.592 | $ 19.401.592 | $ 2.548.193 |

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.
(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.
(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.
(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

### C) *Rebalancing Revenue-to-Cost Ratios*

| | Name of Customer Class | Previously Approved Ratios Most Recent Year: 2016 % | Status Quo Ratios (7C + 7E) / (7A) % | Proposed Ratios (7D + 7E) / (7A) % | Policy Range % |
|---|---|---|---|---|---|
| 1 | Residential | 91.42% | 94.17% | 94.85% | 85 - 115 |
| 2 | GS < 50 | 109.34% | 109.49% | 109.49% | 80 - 120 |
| 3 | GS > 50 | 119.94% | 108.19% | 108.19% | 80 - 120 |
| 4 | Embedded Distributor | | 85.70% | 100.00% | |
| 5 | Street Light | 96.28% | 159.84% | 120.00% | 80 - 120 |
| 6 | Sentinel Light | 91.42% | 104.35% | 104.35% | 80 - 120 |
| 7 | USL | 120.00% | 73.36% | 94.85% | 80 - 120 |
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(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.
(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".
(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

### (D) *Proposed Revenue-to-Cost Ratios* [11]

| | Name of Customer Class | Proposed Revenue-to-Cost Ratio Test Year 2017 | Price Cap IR Period 2018 | 2019 | Policy Range |
|---|---|---|---|---|---|
| 1 | Residential | 94.85% | 94.85% | 94.85% | 85 - 115 |
| 2 | GS < 50 | 109.49% | 109.49% | 109.49% | 80 - 120 |
| 3 | GS > 50 | 108.19% | 108.19% | 108.19% | 80 - 120 |
| 4 | Embedded Distributor | 100.00% | 100.00% | 100.00% | |
| 5 | Street Light | 120.00% | 120.00% | 120.00% | 80 - 120 |
| 6 | Sentinel Light | 104.35% | 104.35% | 104.35% | 80 - 120 |
| 7 | USL | 94.85% | 94.85% | 94.85% | 80 - 120 |
| 8 | | | | | |
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(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

## New Rate Design Policy For Residential Customers

Please complete the following tables.

**A Data Inputs (from Sheet 10. Load Forecast)**

| Test Year Billing Determinants for Residential Class | |
|---|---|
| Customers | 26,074 |
| kWh | 201,294,289 |

| | |
|---|---|
| Proposed Residential Class Specific Revenue Requirement[1] | $ 11,466,426.90 |

| Residential Base Rates on Current Tariff | |
|---|---|
| Monthly Fixed Charge ($) | $ 23.44 |
| Distribution Volumetric Rate ($/kWh) | $ 0.0152 |

**B Current Fixed/Variable Split**

| | Base Rates | Billing Determinants | Revenue | % of Total Revenue |
|---|---|---|---|---|
| Fixed | 23.44 | 26,074 | $ 7,334,094.72 | 70.56% |
| Variable | 0.0152 | 201,294,289 | $ 3,059,673.19 | 29.44% |
| **TOTAL** | - | - | $ 10,393,767.91 | - |

**C Calculating Test Year Base Rates**

| | |
|---|---|
| Number of Remaining Rate Design Policy Transition Years[2] | 4 |

| | Test Year Revenue @ Current F/V Split | Test Year Base Rates @ Current F/V Split | Reconciliation - Test Year Base Rates @ Current F/V Split |
|---|---|---|---|
| Fixed | $ 8,090,988.92 | 25.86 | $ 8,091,283.68 |
| Variable | $ 3,375,437.98 | 0.0168 | $ 3,381,744.06 |
| TOTAL | $ 11,466,426.90 | - | $ 11,473,027.74 |

| | New F/V Split | Revenue @ new F/V Split | Final Adjusted Base Rates | Revenue Reconciliation @ Adjusted Rates |
|---|---|---|---|---|
| Fixed | 77.92% | $ 8,934,848.41 | $ 28.56 | $ 8,936,081.28 |
| Variable | 22.08% | $ 2,531,578.49 | $ 0.0126 | $ 2,536,308.04 |
| TOTAL | - | $ 11,466,426.90 | - | $ 11,472,389.32 |

| Checks[3] | |
|---|---|
| Change in Fixed Rate | $ 2.70 |
| Difference Between Revenues @ Proposed Rates and Class Specific | $5,962.42 |
| | 0.05% |

**Notes:**

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

## Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

**Stage in Process:** *Settlement Agreement*

| | Customer and Load Forecast | | | | | Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design) | | | Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Customer Class (From sheet 10. Load Forecast) | Volumetric Charge Determinant | Customers / Connections | kWh | kW or kVA | Total Class Revenue Requirement | Monthly Service Charge | Volumetric | Fixed | Variable |
| 1 | Residential | kWh | 26,074 | 201,294,289 | - | $ 11,466,427 | $ 9,215,196 | $ 2,251,230 | 80.37% | 19.63% |
| 2 | GS < 50 | kWh | 2,489 | 69,390,323 | - | $ 2,669,649 | $ 923,494 | $ 1,746,155 | 34.59% | 65.41% |
| 3 | GS > 50 | kW | 217 | 190,144,345 | 610,067 | $ 4,672,489 | $ 432,568 | $ 4,239,921 | 9.26% | 90.74% |
| 4 | Embedded Distributor | kW | 1 | 5,205,754 | 13,921 | $ 123,127 | $ 7,251 | $ 115,875 | 5.89% | 94.11% |
| 5 | Street Light | kW | 5,713 | 2,991,556 | 9,240 | $ 352,402 | $ 272,466 | $ 79,936 | 77.32% | 22.68% |
| 6 | Sentinel Light | kW | 695 | 629,014 | 1,916 | $ 58,815 | $ 46,445 | $ 12,370 | 78.97% | 21.03% |
| 7 | USL | kWh | 35 | 1,462,761 | - | $ 58,682 | $ 20,295 | $ 38,387 | 34.58% | 65.42% |
| 8 | | | - | - | - | | | | | |
| 9 | | | - | - | - | | | | | |
| # | | | - | - | - | | | | | |
| # | | | - | - | - | | | | | |
| # | | | - | - | - | | | | | |
| # | | | - | - | - | | | | | |
| # | | | - | - | - | | | | | |
| # | | | - | - | - | | | | | |
| # | | | - | - | - | | | | | |
| # | | | - | - | - | | | | | |
| # | | | - | - | - | | | | | |
| # | | | - | - | - | | | | | |
| # | | | - | - | - | | | | | |

| | | | Distribution Rates | | | | | Revenue Reconciliation | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Monthly Service Charge | | Volumetric Rate | | | | | |
| | Customer Class | Transformer Ownership Allowance [1] ($) | Rate | No. of decimals | Rate | | No. of decimals | MSC Revenues | Volumetric revenues | Distribution Revenues less Transformer Ownership |
| 1 | Residential | | $29.45 | 2 | $0.0112 | /kWh | 4 | $ 9,214,551.60 | $ 2,254,496.0368 | $11,469,047.64 |
| 2 | GS < 50 | | $30.92 | | $0.0252 | /kWh | | $ 923,518.56 | $ 1,748,636.1396 | $ 2,672,154.70 |
| 3 | GS > 50 | $ 205,287 | $166.12 | | $7.2864 | /kW | | $ 432,576.48 | $ 4,445,192.1888 | $ 4,672,481.67 |
| 4 | Embedded Distributor | | $604.27 | | $8.3238 | /kW | | $ 7,251.24 | $ 115,875.6198 | $ 123,126.86 |
| 5 | Street Light | | $3.97 | | $8.6511 | /kW | | $ 272,167.32 | $ 79,936.1640 | $ 352,103.48 |
| 6 | Sentinel Light | | $5.57 | | $6.4563 | /kW | | $ 46,453.80 | $ 12,370.2708 | $ 58,824.07 |
| 7 | USL | | $48.32 | | $0.0262 | /kWh | | $ 20,294.40 | $ 38,324.3382 | $ 58,618.74 |
| 8 | | | | | | | | $ - | $ - | $ - |
| 9 | | | | | | | | $ - | $ - | $ - |
| # | | | | | | | | $ - | $ - | $ - |
| # | | | | | | | | $ - | $ - | $ - |
| # | | | | | | | | $ - | $ - | $ - |
| # | | | | | | | | $ - | $ - | $ - |
| # | | | | | | | | $ - | $ - | $ - |
| # | | | | | | | | $ - | $ - | $ - |
| # | | | | | | | | $ - | $ - | $ - |
| # | | | | | | | | $ - | $ - | $ - |
| # | | | | | | | | $ - | $ - | $ - |
| # | | | | | | | | $ - | $ - | $ - |
| # | | | | | | | | $ - | $ - | $ - |

**Total Transformer Ownership Allowance** $ 205,287

| | |
|---|---|
| **Total Distribution Revenues** | $19,406,357.16 |
| **Base Revenue Requirement** | $19,401,588.02 |
| **Difference** | $ 4,769.14 |
| **% Difference** | 0.025% |

Rates recover revenue requirement

**Notes:**

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

# Revenue Requirement Workform (RRWF) for 2017 Filers

## Tracking Form

**The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)**

**Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.**

**(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)**

**(2) Short description of change, issue, etc.**

### *Summary of Proposed Changes*

| | | | Cost of Capital | | Rate Base and Capital Expenditures | | | Operating Expenses | | | Revenue Requirement | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Reference [1] | Item / Description [2] | Regulated Return on Capital | Regulated Rate of Return | Rate Base | Working Capital | Working Capital Allowance ($) | Amortization / Depreciation | Taxes/PILs | OM&A | Service Revenue Requirement | Other Revenues | Base Revenue Requirement | Grossed up Revenue Deficiency / Sufficiency |
| | | **Original Application** | $ 6,456,937 | 7.18% | $ 89,924,481 | $ 72,787,072 | $ 5,459,030 | $ 4,766,330 | $ 526,758 | $ 10,441,723 | $ 22,294,748 | $ 2,424,445 | $ 19,870,303 | $ 2,441,458 |
| 1 | N/A | Formula error correction in tab 8. cell F34 to get to correct starting point for Grossed up Rev Def/Suff. | $ 6,456,937 | 7.18% | $ 89,924,481 | $ 72,787,072 | $ 5,459,030 | $ 4,766,330 | $ 526,758 | $ 10,441,723 | $ 22,294,748 | $ 2,424,445 | $ 19,870,303 | $ 2,316,326 |
| | | Change | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | -$ 125,132 |
| 2 | 2-EP-5 | Reduced 2016 capitalized expenditures of $483,000, 2017 depreciation of $41,334 | $ 6,425,224 | 7.18% | $ 89,482,815 | $ 72,787,072 | $ 5,459,030 | $ 4,724,996 | $ 572,394 | $ 10,441,723 | $ 22,267,337 | $ 2,424,445 | $ 19,842,892 | $ 2,288,915 |
| | | Change | -$ 31,713 | 0.00% | -$ 441,666 | $ - | $ - | -$ 41,334 | $ 45,636 | $ - | -$ 27,411 | $ - | -$ 27,411 | -$ 27,411 |
| 3 | 1-Staff-17 | $30,000 letter of credit fees | $ 6,425,386 | 7.18% | $ 89,485,065 | $ 72,817,072 | $ 5,461,280 | $ 4,724,996 | $ 572,424 | $ 10,471,723 | $ 22,297,529 | $ 2,424,445 | $ 19,873,084 | $ 2,319,106 |
| | | Change | $ 162 | 0.00% | $ 2,250 | $ 30,000 | $ 2,250 | $ - | $ 30 | $ 30,000 | $ 30,192 | $ - | $ 30,192 | $ 30,192 |
| 4 | 3.0-VECC-23 | $30,000 interest and dividend income | $ 6,425,386 | 7.18% | $ 89,485,065 | $ 72,817,072 | $ 5,461,280 | $ 4,724,996 | $ 572,424 | $ 10,471,723 | $ 22,297,529 | $ 2,454,445 | $ 19,843,084 | $ 2,289,106 |
| | | Change | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 30,000 | -$ 30,000 | -$ 30,000 |
| 5 | 3.0-VECC-18 | Cost of power updated based on new load forecast and other price updates | $ 6,438,128 | 7.18% | $ 89,662,520 | $ 75,183,128 | $ 5,638,735 | $ 4,724,996 | $ 574,776 | $ 10,471,723 | $ 22,312,623 | $ 2,454,445 | $ 19,858,178 | $ 2,304,200 |
| | | Change | $ 12,742 | 0.00% | $ 177,454 | $ 2,366,056 | $ 177,454 | $ - | $ 2,352 | $ - | $ 15,094 | $ - | $ 15,094 | $ 15,094 |
| 6 | 3.0-VECC-18 | Change in revenue due to new load forecast | $ 6,438,128 | 7.18% | $ 89,662,520 | $ 75,183,128 | $ 5,638,735 | $ 4,724,996 | $ 574,776 | $ 10,471,723 | $ 22,312,623 | $ 2,454,445 | $ 19,858,178 | $ 2,125,212 |
| | | Change | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | -$ 178,988 |
| 7 | JTC 1.3 | Change in OEB 4375 revenue based on inclusion of grossed up PILS and adjusted for cost of capital changes | $ 6,438,128 | 7.18% | $ 89,662,520 | $ 75,183,128 | $ 5,638,735 | $ 4,724,996 | $ 574,776 | $ 10,471,723 | $ 22,312,623 | $ 2,448,193 | $ 19,864,430 | $ 2,131,464 |
| | | Change | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | -$ 6,252 | $ 6,252 | $ 6,252 |
| 8 | JTC 1.1 | Change in cost of capital parameters | $ 6,129,330 | 6.84% | $ 89,662,520 | $ 75,183,128 | $ 5,638,735 | $ 4,724,996 | $ 521,759 | $ 10,471,723 | $ 21,950,808 | $ 2,448,193 | $ 19,502,615 | $ 1,769,650 |
| | | Change | -$ 308,798 | -0.34% | $ - | $ - | $ - | $ - | -$ 53,017 | $ - | -$ 361,815 | $ - | -$ 361,815 | -$ 361,814 |

# Attachment B – 2016 and 2017 Fixed Asset Continuity Schedule

## 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 | Adjustments | Cost End of Period | Allocations | Closing Balance | Opening Balance | Additions | Disposals | Adjustments | Cost End of Period | Allocations | Closing Balance | Net Book Value |
| ECE | 1608 | Franchises & Consents | $ 156,053 | $ - | $ - | $ - | $ 156,053 | $ - | $ 156,053 | -$ 46,816 | -$ 3,901 | $ - | $ - | -$ 50,717 | $ - | -$ 50,717 | $ 105,336 |
| 1 | 1610 | Misc. Intangible Plant | $ 40,576 | $ - | $ - | $ - | $ 40,576 | $ - | $ 40,576 | -$ 6,724 | -$ 1,014 | $ - | $ - | -$ 7,738 | $ - | -$ 7,738 | $ 32,837 |
| 12 | 1611 | Computer Software (Formally known as Account 1925) | $ 964,671 | $ 679,305 | $ - | $ - | $ 1,643,976 | $ - | $ 1,643,976 | -$ 419,256 | -$ 224,456 | $ - | $ - | -$ 643,712 | $ - | -$ 643,712 | $ 1,000,264 |
| 12 | 1611A | Computer Software (Formally known as Account 1925) | $ 11,040,525 | $ 603,891 | $ - | $ 4,500 | $ 11,648,916 | $ - | $ 11,648,916 | -$ 7,205,019 | -$ 659,095 | $ - | -$ 225 | -$ 7,864,339 | $ - | -$ 7,864,339 | $ 3,784,577 |
| CEC | 1612 | Land Rights (Formally known as Account 1906) | $ 325,919 | $ 20,377 | $ - | $ - | $ 346,296 | $ - | $ 346,296 | -$ 105,585 | -$ 7,146 | $ - | $ - | -$ 112,730 | $ - | -$ 112,730 | $ 233,566 |
| N/A | 1805 | Land | $ 206,654 | $ 4,862 | $ - | $ - | $ 211,516 | $ - | $ 211,516 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 211,516 |
| 47 | 1808 | Buildings | $ 3,475,850 | $ 233,975 | $ - | $ - | $ 3,709,825 | $ - | $ 3,709,825 | -$ 1,069,628 | -$ 71,857 | $ - | $ - | -$ 1,141,485 | $ - | -$ 1,141,485 | $ 2,568,340 |
| 13 | 1810 | Leasehold Improvements | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1815 | Transformer Station Equipment >50 kV | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1820 | Distribution Station Equipment <50 kV | $ 11,677,936 | $ 342,800 | $ - | $ - | $ 12,020,736 | $ - | $ 12,020,736 | -$ 3,327,685 | -$ 228,543 | $ - | $ - | -$ 3,556,228 | $ - | -$ 3,556,228 | $ 8,464,508 |
| 47 | 1820A | Distribution Station Equipment <50 kV | $ 2,213,650 | $ 1,705,161 | $ - | $ - | $ 3,918,811 | $ - | $ 3,918,811 | -$ 331,338 | -$ 76,065 | $ - | $ - | -$ 407,403 | $ - | -$ 407,403 | $ 3,511,408 |
| 47 | 1825 | Storage Battery Equipment | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1830 | Poles, Towers & Fixtures | $ 25,667,632 | $ 2,344,593 | $ - | $ - | $ 28,012,225 | $ - | $ 28,012,225 | -$ 10,413,291 | -$ 625,581 | $ - | $ - | -$ 11,038,872 | $ - | -$ 11,038,872 | $ 16,973,353 |
| 47 | 1835 | Overhead Conductors & Devices | $ 32,517,505 | $ 1,311,266 | $ - | $ - | $ 33,828,771 | $ - | $ 33,828,771 | -$ 9,872,643 | -$ 754,148 | $ - | $ - | -$ 10,626,791 | $ - | -$ 10,626,791 | $ 23,201,980 |
| 47 | 1840 | Underground Conduit | $ 1,173,463 | $ 208,790 | $ - | $ - | $ 1,382,253 | $ - | $ 1,382,253 | -$ 466,866 | -$ 33,948 | $ - | $ - | -$ 500,814 | $ - | -$ 500,814 | $ 881,439 |
| 47 | 1845 | Underground Conductors & Devices | $ 9,262,719 | $ 412,827 | $ - | $ - | $ 9,675,545 | $ - | $ 9,675,545 | -$ 2,290,628 | -$ 231,806 | $ - | $ - | -$ 2,522,435 | $ - | -$ 2,522,435 | $ 7,153,111 |
| 47 | 1850 | Line Transformers | $ 15,232,767 | $ 1,714,937 | $ - | $ - | $ 16,947,704 | $ - | $ 16,947,704 | -$ 6,137,668 | -$ 452,736 | $ - | $ - | -$ 6,590,404 | $ - | -$ 6,590,404 | $ 10,357,301 |
| 47 | 1855 | Services (Overhead & Underground) | $ 10,879,936 | $ 724,666 | $ - | $ - | $ 11,604,602 | $ - | $ 11,604,602 | -$ 3,287,542 | -$ 258,128 | $ - | $ - | -$ 3,545,670 | $ - | -$ 3,545,670 | $ 8,058,932 |
| 47 | 1860 | Meters | $ 624,091 | $ - | $ - | $ - | $ 624,091 | $ - | $ 624,091 | -$ 200,989 | -$ 19,815 | $ - | $ - | -$ 220,805 | $ - | -$ 220,805 | $ 403,286 |
| 47 | 1860A | Meters (Smart Meters) | $ 5,267,102 | $ 228,500 | -$ 79,179 | $ 244,865 | $ 5,661,288 | $ - | $ 5,661,288 | -$ 2,162,516 | -$ 432,949 | $ 31,289 | -$ 23,767 | -$ 2,587,944 | $ - | -$ 2,587,944 | $ 3,073,344 |
| 47 | 1860B | Meters | $ 592,403 | $ 79,807 | $ - | $ - | $ 672,210 | $ - | $ 672,210 | -$ 329,631 | -$ 19,360 | $ - | $ - | -$ 348,991 | $ - | -$ 348,991 | $ 323,219 |
| 1 | 1865 | D Other Install on Cust Prem | $ 133,938 | $ - | $ - | $ - | $ 133,938 | $ - | $ 133,938 | -$ 70,947 | -$ 13,394 | $ - | $ - | -$ 84,341 | $ - | -$ 84,341 | $ 49,597 |
| | 1875 | D St Lites & Signal Systems | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| N/A | 1905 | Land | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1908 | Buildings & Fixtures | $ 912,520 | $ 20,000 | $ - | $ - | $ 932,520 | $ - | $ 932,520 | -$ 218,453 | -$ 18,450 | $ - | $ - | -$ 236,903 | $ - | -$ 236,903 | $ 695,617 |
| 13 | 1910 | Leasehold Improvements | $ 885,142 | $ 49,746 | $ - | $ - | $ 934,889 | $ - | $ 934,889 | -$ 546,456 | -$ 131,176 | $ - | $ - | -$ 677,631 | $ - | -$ 677,631 | $ 257,257 |
| 8 | 1915 | Office Furniture & Equipment (10 years) | $ 1,500,666 | $ 23,000 | $ - | $ - | $ 1,523,666 | $ - | $ 1,523,666 | -$ 1,337,297 | -$ 24,719 | $ - | $ - | -$ 1,362,016 | $ - | -$ 1,362,016 | $ 161,650 |
| 8 | 1915 | Office Furniture & Equipment (5 years) | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 10 | 1920 | Computer Equipment - Hardware | $ 3,792,341 | $ 475,768 | $ - | $ - | $ 4,268,108 | $ - | $ 4,268,108 | -$ 3,187,926 | -$ 298,642 | $ - | $ - | -$ 3,486,568 | $ - | -$ 3,486,568 | $ 781,541 |
| 45 | 1920 | Computer Equip.-Hardware(Post Mar. 22/04) | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 45.1 | 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 10 | 1930 | Transportation Equipment (5 years) | $ 594,329 | $ 72,700 | $ - | $ - | $ 667,029 | $ - | $ 667,029 | -$ 433,206 | -$ 75,811 | $ - | $ - | -$ 509,017 | $ - | -$ 509,017 | $ 158,012 |
| 10 | 1930A | Transportation Equipment (10 years) | $ 3,464,915 | $ 294,300 | $ - | $ - | $ 3,759,215 | $ - | $ 3,759,215 | -$ 1,990,779 | -$ 302,672 | $ - | $ - | -$ 2,293,451 | $ - | -$ 2,293,451 | $ 1,465,764 |
| 8 | 1935 | Stores Equipment | $ 166,638 | $ - | $ - | $ - | $ 166,638 | $ - | $ 166,638 | -$ 166,638 | $ - | $ - | $ - | -$ 166,638 | $ - | -$ 166,638 | $ - |
| 8 | 1940 | Tools, Shop & Garage Equipment | $ 869,792 | $ 50,000 | $ - | $ - | $ 919,792 | $ - | $ 919,792 | -$ 710,816 | -$ 25,395 | $ - | $ - | -$ 736,211 | $ - | -$ 736,211 | $ 183,582 |
| 8 | 1945 | Measurement & Testing Equipment | $ 515,191 | $ - | $ - | $ - | $ 515,191 | $ - | $ 515,191 | -$ 471,665 | -$ 12,127 | $ - | $ - | -$ 483,792 | $ - | -$ 483,792 | $ 31,399 |
| 8 | 1950 | Power Operated Equipment | $ 109,339 | $ 18,000 | $ - | $ - | $ 127,339 | $ - | $ 127,339 | -$ 100,148 | -$ 3,314 | $ - | $ - | -$ 103,462 | $ - | -$ 103,462 | $ 23,878 |
| 8 | 1955 | Communications Equipment | $ 1,113,327 | $ 35,160 | $ - | $ - | $ 1,148,487 | $ - | $ 1,148,487 | -$ 774,362 | -$ 80,212 | $ - | $ - | -$ 854,574 | $ - | -$ 854,574 | $ 293,912 |
| 8 | 1955 | Communication Equipment (Smart Meters) | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 8 | 1960 | Miscellaneous Equipment (10 years) | $ 85,031 | $ - | $ - | $ - | $ 85,031 | $ - | $ 85,031 | -$ 67,483 | -$ 4,358 | $ - | $ - | -$ 71,841 | $ - | -$ 71,841 | $ 13,190 |
| 8 | 1960A | Miscellaneous Equipment (5 years) | $ 91,387 | $ - | $ - | $ - | $ 91,387 | $ - | $ 91,387 | -$ 71,984 | -$ 4,797 | $ - | $ - | -$ 76,780 | $ - | -$ 76,780 | $ 14,606 |
| 47 | 1975 | Load Management Controls Utility Premises | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1980 | System Supervisor Equipment | $ 1,046,816 | $ - | $ - | $ - | $ 1,046,816 | $ - | $ 1,046,816 | -$ 719,618 | -$ 21,396 | $ - | $ - | -$ 741,014 | $ - | -$ 741,014 | $ 305,802 |
| 47 | 1985 | Miscellaneous Fixed Assets | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1990 | Other Tangible Property | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1995 | Contributions & Grants | -$ 13,707,783 | -$ 1,470,207 | $ - | $ - | -$ 15,177,990 | $ - | -$ 15,177,990 | $ 2,600,323 | $ 309,718 | $ - | $ - | $ 2,910,041 | $ - | $ 2,910,041 | -$ 12,267,950 |
| 47 | 2440 | Deferred Revenue[5] | | | | | $ - | | $ - | | | | | | | $ - | $ - |
| | | | | | | | | | | | | | | | | $ - | $ - |
| | | **Sub-Total** | **$ 132,893,041** | **$ 10,184,225** | **-$ 79,179** | **$ 249,365** | **$ 143,247,451** | **$ -** | **$ 143,247,451** | **-$ 55,941,279** | **-$ 4,807,293** | **$ 31,289** | **-$ 23,992** | **-$ 60,741,275** | **$ -** | **-$ 60,741,275** | **$ 82,506,177** |
| | | | | | | | | | | | | | | | | | |
| | 2055 | Asset Under Construction | $ 3,372,695 | -$ 1,037,000 | $ - | -$ 234,065 | $ 2,101,630 | $ - | $ 2,101,630 | -$ 7,802 | $ - | $ - | $ 7,802 | $ - | | $ - | $ 2,101,630 |
| | | **Less Socialized Renewable Energy Generation Investments** (input as negative) | | | | | | | $ - | | | | | | | $ - | $ - |
| | | ***Less Other Non Rate-Regulated Utility Assets (input as negative)*** | | | | | | | $ - | | | | | | | $ - | $ - |
| | | **Total PP&E** | **$ 136,265,736** | **$ 9,147,225** | **-$ 79,179** | **$ 15,300** | **$ 145,349,082** | **$ -** | **$ 145,349,082** | **-$ 55,949,081** | **-$ 4,807,293** | **$ 31,289** | **-$ 16,190** | **-$ 60,741,275** | **$ -** | **-$ 60,741,275** | **$ 84,607,807** |
| | | **Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]** | | | | | | | | | | | | | | | |
| | | **Total** | | | | | | | | | **-$ 4,807,293** | | | | | | |

| | | |
|---|---|---|
| 10 | | Transportation |
| 8 | | Stores Equipment |

**Less:** *Fully Allocated Depreciation*

| | |
|---|---|
| Transportation | -$ 378,482 |
| Stores Equipment | |
| **Net Depreciation** | -$ 4,428,810 |

## 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 | Adjustments | Cost End of Period | Allocations | Closing Balance | Opening Balance | Additions | Disposals | Adjustments | Cost End of Period | Allocations | Closing Balance | Net Book Value |
| ECE | 1608 | Franchises & Consents | $ 156,053 | $ - | $ - | $ - | $ 156,053 | $ - | $ 156,053 | -$ 50,717 | -$ 3,901 | $ - | $ - | -$ 54,619 | $ - | -$ 54,619 | $ 101,434 |
| 1 | 1610 | Misc. Intangible Plant | $ 40,576 | $ - | $ - | $ - | $ 40,576 | $ - | $ 40,576 | -$ 7,738 | -$ 1,014 | $ - | $ - | -$ 8,753 | $ - | -$ 8,753 | $ 31,823 |
| 12 | 1611 | Computer Software (Formally known as Account 1925) | $ 1,643,976 | $ 300,531 | $ - | $ - | $ 1,944,507 | $ - | $ 1,944,507 | -$ 643,712 | -$ 320,823 | $ - | $ - | -$ 964,535 | $ - | -$ 964,535 | $ 979,972 |
| 12 | 1611A | Computer Software (Formally known as Account 1925) | $ 11,648,916 | $ 973,496 | $ - | $ - | $ 12,622,412 | $ - | $ 12,622,412 | -$ 7,864,339 | -$ 719,153 | $ - | $ - | -$ 8,583,492 | $ - | -$ 8,583,492 | $ 4,038,921 |
| CEC | 1612 | Land Rights (Formally known as Account 1906) | $ 346,296 | $ 20,517 | $ - | $ - | $ 366,814 | $ - | $ 366,814 | -$ 112,730 | -$ 7,657 | $ - | $ - | -$ 120,387 | $ - | -$ 120,387 | $ 246,427 |
| N/A | 1805 | Land | $ 211,516 | $ 123,387 | $ - | $ - | $ 334,903 | $ - | $ 334,903 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 334,903 |
| 47 | 1808 | Buildings | $ 3,709,825 | $ 32,472 | $ - | $ - | $ 3,742,297 | $ - | $ 3,742,297 | -$ 1,141,485 | -$ 74,521 | $ - | $ - | -$ 1,216,006 | $ - | -$ 1,216,006 | $ 2,526,291 |
| 13 | 1810 | Leasehold Improvements | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1815 | Transformer Station Equipment >50 kV | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1820 | Distribution Station Equipment <50 kV | $ 12,020,736 | $ 118,700 | $ - | $ - | $ 12,139,436 | $ - | $ 12,139,436 | -$ 3,556,228 | -$ 233,158 | $ - | $ - | -$ 3,789,386 | $ - | -$ 3,789,386 | $ 8,350,051 |
| 47 | 1820A | Distribution Station Equipment <50 kV | $ 3,918,811 | $ 1,350,963 | $ - | $ - | $ 5,269,774 | $ - | $ 5,269,774 | -$ 407,403 | -$ 114,267 | $ - | $ - | -$ 521,669 | $ - | -$ 521,669 | $ 4,748,105 |
| 47 | 1825 | Storage Battery Equipment | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1830 | Poles, Towers & Fixtures | $ 28,012,225 | $ 2,367,461 | $ - | $ - | $ 30,379,686 | $ - | $ 30,379,686 | -$ 11,038,872 | -$ 677,934 | $ - | $ - | -$ 11,716,806 | $ - | -$ 11,716,806 | $ 18,662,880 |
| 47 | 1835 | Overhead Conductors & Devices | $ 33,828,771 | $ 1,347,941 | $ - | $ - | $ 35,176,712 | $ - | $ 35,176,712 | -$ 10,626,791 | -$ 783,127 | $ - | $ - | -$ 11,409,918 | $ - | -$ 11,409,918 | $ 23,766,795 |
| 47 | 1840 | Underground Conduit | $ 1,382,253 | $ 239,209 | $ - | $ - | $ 1,621,462 | $ - | $ 1,621,462 | -$ 500,814 | -$ 26,179 | $ - | $ - | -$ 526,993 | $ - | -$ 526,993 | $ 1,094,469 |
| 47 | 1845 | Underground Conductors & Devices | $ 9,675,545 | $ 226,194 | $ - | $ - | $ 9,901,740 | $ - | $ 9,901,740 | -$ 2,522,435 | -$ 237,144 | $ - | $ - | -$ 2,759,578 | $ - | -$ 2,759,578 | $ 7,142,161 |
| 47 | 1850 | Line Transformers | $ 16,947,704 | $ 1,636,697 | $ - | $ - | $ 18,584,401 | $ - | $ 18,584,401 | -$ 6,590,404 | -$ 494,631 | $ - | $ - | -$ 7,085,035 | $ - | -$ 7,085,035 | $ 11,499,366 |
| 47 | 1855 | Services (Overhead & Underground) | $ 11,604,602 | $ 512,630 | $ - | $ - | $ 12,117,232 | $ - | $ 12,117,232 | -$ 3,545,670 | -$ 273,594 | $ - | $ - | -$ 3,819,265 | $ - | -$ 3,819,265 | $ 8,297,968 |
| 47 | 1860 | Meters | $ 624,091 | $ - | $ - | $ - | $ 624,091 | $ - | $ 624,091 | -$ 220,805 | -$ 19,061 | $ - | $ - | -$ 239,865 | $ - | -$ 239,865 | $ 384,226 |
| 47 | 1860A | Meters (Smart Meters) | $ 5,661,288 | $ 196,252 | $ - | $ - | $ 5,857,540 | $ - | $ 5,857,540 | -$ 2,587,944 | -$ 457,504 | $ - | $ - | -$ 3,045,448 | $ - | -$ 3,045,448 | $ 2,812,092 |
| 47 | 1860B | Meters | $ 672,210 | $ 81,202 | $ - | $ - | $ 753,412 | $ - | $ 753,412 | -$ 348,991 | -$ 21,123 | $ - | $ - | -$ 370,114 | $ - | -$ 370,114 | $ 383,297 |
| 1 | 1865 | D Other Install on Cust Prem | $ 133,938 | $ - | $ - | $ - | $ 133,938 | $ - | $ 133,938 | -$ 84,341 | -$ 13,394 | $ - | $ - | -$ 97,735 | $ - | -$ 97,735 | $ 36,203 |
| | 1875 | D St Lites & Signal Systems | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| N/A | 1905 | Land | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1908 | Buildings & Fixtures | $ 932,520 | $ 20,000 | $ - | $ - | $ 952,520 | $ - | $ 952,520 | -$ 236,903 | -$ 18,850 | $ - | $ - | -$ 255,754 | $ - | -$ 255,754 | $ 696,766 |
| 13 | 1910 | Leasehold Improvements | $ 934,889 | $ 85,389 | $ - | $ - | $ 1,020,277 | $ - | $ 1,020,277 | -$ 677,631 | -$ 114,298 | $ - | $ - | -$ 791,929 | $ - | -$ 791,929 | $ 228,348 |
| 8 | 1915 | Office Furniture & Equipment (10 years) | $ 1,523,666 | $ 23,500 | $ - | $ - | $ 1,547,166 | $ - | $ 1,547,166 | -$ 1,362,016 | -$ 24,964 | $ - | $ - | -$ 1,386,980 | $ - | -$ 1,386,980 | $ 160,187 |
| 8 | 1915 | Office Furniture & Equipment (5 years) | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 10 | 1920 | Computer Equipment - Hardware | $ 4,268,108 | $ 354,153 | $ - | $ - | $ 4,622,261 | $ - | $ 4,622,261 | -$ 3,486,568 | -$ 311,498 | $ - | $ - | -$ 3,798,065 | $ - | -$ 3,798,065 | $ 824,195 |
| 45 | 1920 | Computer Equip.-Hardware(Post Mar. 22/04) | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 45.1 | 1920 | Computer Equip.-Hardware(Post Mar. 19/07) | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 10 | 1930 | Transportation Equipment (5 years) | $ 667,029 | $ 17,500 | $ - | $ - | $ 684,529 | $ - | $ 684,529 | -$ 509,017 | -$ 64,417 | $ - | $ - | -$ 573,433 | $ - | -$ 573,433 | $ 111,096 |
| 10 | 1930A | Transportation Equipment (10 years) | $ 3,759,215 | $ 157,500 | $ - | $ - | $ 3,916,715 | $ - | $ 3,916,715 | -$ 2,293,451 | -$ 301,571 | $ - | $ - | -$ 2,595,022 | $ - | -$ 2,595,022 | $ 1,321,693 |
| 8 | 1935 | Stores Equipment | $ 166,638 | $ - | $ - | $ - | $ 166,638 | $ - | $ 166,638 | -$ 166,638 | $ - | $ - | $ - | -$ 166,638 | $ - | -$ 166,638 | $ - |
| 8 | 1940 | Tools, Shop & Garage Equipment | $ 919,792 | $ 60,000 | $ - | $ - | $ 979,792 | $ - | $ 979,792 | -$ 736,211 | -$ 30,700 | $ - | $ - | -$ 766,911 | $ - | -$ 766,911 | $ 212,882 |
| 8 | 1945 | Measurement & Testing Equipment | $ 515,191 | $ - | $ - | $ - | $ 515,191 | $ - | $ 515,191 | -$ 483,792 | -$ 5,282 | $ - | $ - | -$ 489,074 | $ - | -$ 489,074 | $ 26,117 |
| 8 | 1950 | Power Operated Equipment | $ 127,339 | $ 18,000 | $ - | $ - | $ 145,339 | $ - | $ 145,339 | -$ 103,462 | -$ 5,114 | $ - | $ - | -$ 108,575 | $ - | -$ 108,575 | $ 36,764 |
| 8 | 1955 | Communications Equipment | $ 1,148,487 | $ 43,463 | $ - | $ - | $ 1,191,950 | $ - | $ 1,191,950 | -$ 854,574 | -$ 82,203 | $ - | $ - | -$ 936,777 | $ - | -$ 936,777 | $ 255,172 |
| 8 | 1955 | Communication Equipment (Smart Meters) | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 8 | 1960 | Miscellaneous Equipment (10 years) | $ 85,031 | $ - | $ - | $ - | $ 85,031 | $ - | $ 85,031 | -$ 71,841 | -$ 3,088 | $ - | $ - | -$ 74,929 | $ - | -$ 74,929 | $ 10,102 |
| 8 | 1960A | Miscellaneous Equipment (5 years) | $ 91,387 | $ - | $ - | $ - | $ 91,387 | $ - | $ 91,387 | -$ 76,780 | -$ 4,797 | $ - | $ - | -$ 81,577 | $ - | -$ 81,577 | $ 9,810 |
| 47 | 1975 | Load Management Controls Utility Premises | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1980 | System Supervisor Equipment | $ 1,046,816 | $ - | $ - | $ - | $ 1,046,816 | $ - | $ 1,046,816 | -$ 741,014 | -$ 21,401 | $ - | $ - | -$ 762,415 | $ - | -$ 762,415 | $ 284,401 |
| 47 | 1985 | Miscellaneous Fixed Assets | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1990 | Other Tangible Property | | | | | $ - | | $ - | | | | | $ - | | $ - | $ - |
| 47 | 1995 | Contributions & Grants | -$ 15,177,990 | -$ 550,000 | $ - | $ - | -$ 15,727,990 | $ - | -$ 15,727,990 | $ 2,910,041 | $ 332,872 | $ - | $ - | $ 3,242,913 | $ - | $ 3,242,913 | -$ 12,485,078 |
| 47 | 2440 | Deferred Revenue[5] | | | | | $ - | | $ - | | | | | | | $ - | $ - |
| | | | | | | | | | | | | | | | | $ - | $ - |
| | | **Sub-Total** | **$ 143,247,451** | **$ 9,757,158** | **$ -** | **$ -** | **$ 153,004,610** | **$ -** | **$ 153,004,610** | **-$ 60,741,275** | **-$ 5,133,494** | **$ -** | **$ -** | **-$ 65,874,769** | **$ -** | **-$ 65,874,769** | **$ 87,129,840** |
| | | | | | | | | | | | | | | | | | |
| | 2055 | Asset Under Construction | $ 2,101,630 | $ - | $ - | $ - | $ 2,101,630 | $ - | $ 2,101,630 | $ - | $ - | $ - | $ - | $ - | | $ - | $ 2,101,630 |
| | | **Less Socialized Renewable Energy Generation Investments (input as negative)** | | | | | | | $ - | | | | | | | $ - | $ - |
| | | ***Less Other Non Rate-Regulated Utility Assets (input as negative)*** | | | | | | | $ - | | | | | | | $ - | $ - |
| | | **Total PP&E** | **$ 145,349,082** | **$ 9,757,158** | **$ -** | **$ -** | **$ 155,106,240** | **$ -** | **$ 155,106,240** | **-$ 60,741,275** | **-$ 5,133,494** | **$ -** | **$ -** | **-$ 65,874,769** | **$ -** | **-$ 65,874,769** | **$ 89,231,471** |
| | | **Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]** | | | | | | | | | | | | | | | |
| | | **Total** | | | | | | | | | **-$ 5,133,494** | | | | | | |

| | | |
|---|---|---|
| 10 | | Transportation |
| 8 | | Stores Equipment |

**Less:** *Fully Allocated Depreciation*

| | |
|---|---|
| Transportation | -$ 365,987 |
| Stores Equipment | |
| **Net Depreciation** | -$ 4,767,507 |

# Tab 2 – Bios of Witnesses

**CANADIAN NIAGARA POWER INC.**

**Curriculum Vitae of**

**Glen King, CPA, CA**

## EDUCATION

- 1990 Chartered Professional Accountant, Chartered Accountant
- 1988 Bachelor of Commerce (Co-operative) - Memorial University of Newfoundland

## BUSINESS EXPERIENCE

- 2005 to Present
  FortisOntario Inc.
  Vice President, Finance & Chief Financial Officer
- 2003 to 2005
  Canadian Niagara Power Inc.
  Director, Finance
  Treasurer
- 2001 to 2003
  Newfoundland Power
  Director, Finance
- 1995 to 2001
  Fortis Trust Corporation
  Vice President, Finance
- 1988 to 1995
  Deloitte & Touche Chartered Accountants
  Senior Manager
  Manager
  Auditor
  Student

**CANADIAN NIAGARA POWER INC.**

**Curriculum Vitae of**

**Jie Han, P.Eng., MBA**

## EDUCATION

- 2012 Executive Master of Business Administration
  University at Buffalo (SUNY), Buffalo, New York
- 1983 Bachelor of Electrical Engineering
  Tsing Hua University, Beijing, China

## BUSINESS EXPERIENCE

- 2014 to Present FortisOntario Inc.
  Vice President, Operations
- 2004 to 2014 FortisOntario Inc.
  Director Technical Services
- 1990 to 2004 Maritime Electric Company, Limited
  Supervisor, Planning and System Performance
  Supervisor, Operations Planning
  Electrical Engineer, Supervisor – System Operations
- 1983 to 1989 Electric Power Planning and Engineering Institute, Bejing, China

**CANADIAN NIAGARA POWER INC.**

**Curriculum Vitae of**

**Gregory Beharriell, P.Eng.**

## EDUCATION

- 2006 Bachelor of Engineering (Electrical) - Lakehead University
- 2003 Electronics Engineering Technology Diploma - RCC Institute of Technology

## BUSINESS EXPERIENCE

- 2016 to Present — Canadian Niagara Power Inc.
  Manager, Regulatory Affairs
- 2014 to 2016 — Algoma Power Inc.
  Supervisor, Technical Services
- 2010 to 2014 — Algoma Power Inc.
  Distribution Engineer
- 2009 to 2010 — Algoma Power Inc.
  Distribution System Planner
- 2006 to 2009 — Great Lakes Power Limited
  Distribution System Planner

**CANADIAN NIAGARA POWER INC.**

**Curriculum Vitae of**

**Brian Vander Vloet, CPA, CA**

## EDUCATION

- 2010 Chartered Professional Accountant, Chartered Accountant
- 2007 Bachelor of Business Administration Program, Honours with Co-operative Option - Wilfrid Laurier University

## BUSINESS EXPERIENCE

- 2013 to Present Canadian Niagara Power Inc.
  Manager, Regulatory Accounting
- 2010 to 2013 Canadian Niagara Power Inc.
  Regulatory Accountant
- 2008 to 2010 PricewaterhouseCoopers LLP
  Senior Associate
- 2005 to 2006 PricewaterhouseCoopers LLP
  Associate (Co-op terms)

**CANADIAN NIAGARA POWER INC.**

**Curriculum Vitae of**

**Scott Cushing, FSA, FCIA**

## EDUCATION / PROFESSIONAL QUALIFICATIONS

- 2001 Fellow of the Canadian Institute of Actuaries
- 2001 Fellow of the Society of Actuaries
- 1988 Honours Bachelor of Mathematics (Actuarial Science) – University of Waterloo

## BUSINESS EXPERIENCE

- 2005 to Present Mercer (Canada) Limited
  Principal
- 2000 to 2005 Mercer (Canada) Limited
  Consulting Actuary
- 1994 to 2000 Mercer (Canada) Limited
  Actuarial Analyst
- 1988 to 1992 Towers Perrin
  Actuarial Analyst

# Tab 3 – Acknowledgement of Expert's Duty

**FORM A**

Proceeding: EB-2016-0061

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Scott Cushing (*name*). I live at Oakville (*city*), in the province (*province/state*) of Ontario.

2. I have been engaged by or on behalf of Canadian Niagara Power Inc. (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date December 21, 2016

Scott Cushing

*Signature*

# Tab 4 – OM&A Annual Comparison

| **OM&A Annual Comparison** | **2013** | **2014** | **2015** | **2016** | **2017** |
|---|---|---|---|---|---|
| Actual/Forecast OM&A Per Application | 8,864,063 | 9,434,813 | 9,518,933 | 10,160,816 | 10,574,723 |
| CDM Staffing | 85,000 | 29,000 | 29,000 | 3,000 | 3,000 |
| Vehicle Depreciation Credit | 351,000 | | | | |
| Approved IFRS Cost | 85,000 | | | | |
| Port Colborne Service Centre Closure | 35,000 | 55,000 | 55,000 | 55,000 | 55,000 |
| Regulatory Staffing | 100,000 | 100,000 | 100,000 | 100,000 | 100,000 |
| Customer Service Staffing and Charge-Outs | 92,000 | 162,000 | 192,000 | 162,000 | 162,000 |
| Collections and Bad Debts | 8,000 | 107,000 | 78,000 | 29,000 | (9,000) |
| Shared Service Allocation | | (63,000) | (63,000) | (108,000) | (97,000) |
| ON1Call Initiative | | (40,000) | (40,000) | (40,000) | (40,000) |
| Vacant IT Position | | | 40,000 | | |
| IT Billable Costs | | | 28,000 | | |
| Pole Testing Program | | | | (150,000) | (150,000) |
| MIST O&M | | | | (44,000) | (44,000) |
| EAB Program | | | | | (100,000) |
| Load Dispatching | | | | | (65,000) |
| Asset Management | | | | | (30,000) |
| Adjusted OM&A | **9,620,063** | **9,784,813** | **9,937,933** | **10,167,816** | **10,359,723** |
| Variance vs Prior Year (Adjusted - $) | | 164,750 | 153,120 | 229,883 | 191,907 |
| Variance vs Prior Year (Adjusted - %) | | 1.7% | 1.6% | 2.3% | 1.9% |
| OEB Determined Inflation Rate | | 1.7% | 1.6% | 2.1% | 1.9% |
| Difference - Adjusted % Variance vs OEB Inflation Rate | | 0.0% | 0.0% | 0.2% | 0.0% |

# Tab 5 – Summary of Cost Drivers

| Cost Driver | Cost Included in 2-JB | References to Evidence | Drivers, RRFE Outcomes and Value to Customer |
|---|---|---|---|
| ON1Call Initiative | 40,000 | E4/T2/S2/p5 | - Legislated requirement<br>- Public safety |
| Pole Testing Program | 150,000 | E4/T2/S2/p7<br>DSP/DAMP | - Asset management - trend toward requirement for more formal asset condition assessments<br>- Optimization of lifecycle costs<br>- Public and worker safety<br>- Maintain reliability |
| MIST O&M | 44,000 | E4/T2/S2/p7 | - Regulatory requirement<br>- Increased fairness in cost allocation and settlement<br>- Customer opportunity and ability to manage costs through load shifting<br>- Customer opportunity to manage overall consumption through improved data analytics |
| EAB Program | 100,000 | E4/T2/S2/p8<br>DSP/DAMP | - Public safety<br>- Maintain reliability<br>- Collaboration with customers and municipal stakeholders |
| Load Dispatching | 65,000 | E4/T2/S2/p8 | - Worker safety<br>- Improved outage response<br>- Enables improved customer communication during outages in conjunction with after-hours call centre |
| Improved Asset Management (GIS) | 30,000 | E4/T2/S2/p9 | - Enables OMS implementation to improve outage response and customer communications<br>- Enables improved asset management processes<br>- Avoid cost impact of additional staff to meet Significant Natural Area Procedures |

| Cost Driver | Cost Included in 2-JB | References to Evidence | Drivers, RRFE Outcomes and Value to Customer |
|---|---|---|---|
| Public Awareness Surveys and Safety Campaigns | N/A | E1/T1/S2/p8-9 | - Regulatory requirement<br>- Public safety |
| Arc Hazard Identification, Quantification, Procedures | N/A | E1/T1/S2/AppA/p19 | - Worker safety<br>- Avoid damage to equipment |
| Environmental - Significant Natural Area Procedures | N/A | E1/T1/S2/AppA/p20<br>IRR 2-Staff-25 | - Legislative Requirements<br>- Environmental stewardship |
| Increased Customer Engagement | N/A | E1/T3/S1<br>E1/T3/S2 | - Regulatory requirement<br>- Improved customer communication and incorporation of feedback into planning process |
| Improved After-Hours Call Service | N/A | E1/T3/S1/p6 | - Improved customer communication during outages<br>- Reduced outage duration resulting from improved information to workers<br>- Eliminate CNPI response to customer issues (e.g. main breaker tripped) |
| Increased Regulatory Requirements (Chapter 5 Filing Requirements, Scorecard, LEAP/OCEB/OESP/OREC, etc.) | N/A | E1/T3/S2/p1<br>E1/T10/S1<br>E4/T9/S1 | - Overall alignment with RRFE and other regulatory requirements<br>- Increased transparency and accountability to customers<br>- Bill reduction (OCEB, OREC)<br>- Low-income assistance (LEAP, OESP) |
| Non-Linear Design Requirements | N/A | IRR 2-Staff-25 | - Change in standards |

*(page left blank intentionally)*

# Tab 6 – Emerald Ash Borer Materials

Connecting Niagara



# Program in Full-effect

Posted Jul 13th, 2016 in Municipal, Home and Garden, fort erie


"In 2016, the Town will be spending $468,000 for the trimming and removal of trees on Town property. This is a significant increase over last year's budget."

Emerald Ash Borer (EAB) has killed millions of trees in

North America since 2002. It was identified in the Niagara Region in 2009. By 2016, Town staff estimate that approximately 16,500 ash trees in Fort Erie are infested; with about 80 per cent of them located on private property.

EAB is an introduced insect pest from Asia that attacks and kills all species of true ash trees (genus: Fraxinus) by feeding beneath the bark and disrupting the flow of water and nutrients within the tree. Trees infested with EAB, which do not receive proper treatment within a specific period of time, will die. Unlike other tree species, ash trees killed by EAB have full tree failures significantly sooner after they are dead. The mortality rate of EAB infested trees can happen as fast as one year; however, it typically occurs within 2-3 years.

> *“As a result of this infestation, the Town is taking proactive measures to protect our community by removing dying and infected trees from our parks and roadways,” said Mayor Wayne Redekop. “In 2016, the Town will be spending $468,000 for the trimming and removal of trees on Town property. This is a significant increase over last year’s budget.”*

In addition to the work done in 2015, the Town has recently completed a tree removal program in South Fort Erie. Staff has now moved to the Crescent Park area and will continue assessing the EAB impact in that area for the remainder of the year. As part of the EAB program, trees marked by with a white “X” or “X & H” will be removed in an effort to address the potential public safety hazards. Due to this year’s drastic increase in tree removals, approximately $65,000 will be allocated to a re-planting program scheduled to

## From the Blog

### You Can Now Text 911 in an Emergency

Dec 20th, 2016

To be eligible to use this service the cell phone must be; - Registered for T9-1-1 with the DHHSI subscriber's cell phone company in advance - Capable of sending and receiving text (SMS) messages and activated with a service package that includes text messaging - Connected to a cellular network.

### RECIPE: Innovative Baked Cheese Appetizer

Dec 19th, 2016

Including cheese in holiday entertaining is a must, but why not shake up the traditional with something a little different?

## Shop Local in Niagara



## Business Events

Stay connected, meet new people. Find out where:

LEARN MORE!

## Support Local Business

begin in Fall 2016.

While the Town will be removing the selected trees from its property, Fort Erie residents and businesses are reminded that it is their responsibility to manage or remove trees on their own properties.

For more information on the Emerald Ash Borer program in Fort Erie, please call 905-871-1600 or visit www.forterie.ca .

## 0 comments

## Post a Comment

Name:

Email:

Website: *(Optional)*

Comment:

Post Comment

The Municipal Corporation of the
Town of Fort Erie

# Council-in-Budget Committee Meeting #5 Agenda

**Wednesday, February 3, 2016 - 6:00 PM**

**Council Chambers**

## 1. Call to Order

## 2. Roll Call

## 3. Announcements/Addenda

## 4. Disclosure of Pecuniary Interest and General Nature Thereof

## 5. Departmental Operating Budgets

**CBC-07-2016** 2016 General Levy Operating Budget ***(Continued from the January 27, 2016 Council-in-Budget Committee Meeting #4)***

**Recommendation:**

**PART 1**

**That:** Council approves the following Supplementary Base Budget funding for 2016, subject of previous reports/resolutions:

1.1 Capital Reserves strategic investment increase for $600,000
1.2 Road Refurbishing Reserves strategic investment increase for $200,000
1.3 Downtown Core Area Community Improvement Plan (CIP) grant program increase for $30,000
1.4 Emerald Ash Borer tree removal increase for $200,000
1.5 Tree planting increase for $40,000
1.6 Volunteer firefighter training rate increase for $50,000
1.7 Canada Day fireworks contribution of $10,000, and further

**PART 2**

**That**: Council approves the following Supplementary One-Time funding for 2016, subject of previous reports/resolutions:
2.1 Habitat for Humanity grant for $26,962
2.2 Roads Refurbishing Reserves allocation of OMPF funding of $403,100, and further

**PART 3**

**That**: Council approves the following Supplementary Base Budget new funding for 2016:
3.1 Roads crews wages and benefits for $62,000
3.2 Parks winter casual wages and benefits for $25,698, and further

**PART 4**

**That:** Council approves the following Supplementary One-Time new funding for 2016:
4.1 Physician recruitment Operating Reserve increase of $35,000
4.2 Fire Department operational review for $15,000
4.3 Niagara Blvd - Cycle Route expansion contribution for $100,000
4.4 Battle of Ridgeway 150th anniversary event of $55,958
4.5 Women’s Place of South Niagara Inc. grant of $5,000
4.6 Ridgeway BIA tree pit irrigation of $1,557, and further

**PART 5**

**That:** Council approves the following grants for 2016:
5.1 Fort Erie Lions Senior Citizens complex in the amount of $22,750
5.2 BIA watering in the amount of $28,000
5.3 Beachcombers Seniors Complex in the amount of $10,500
5.4 Fort Erie Horticultural Society in the amount of $1,000
5.5 Community Events Grants in the amount of $24,350
5.6 EDTC in the amount of $648,852
5.7 Fort Erie Public Library in the amount of $1,478,087, and further

**PART 6**

**That**: Council approves the following Business Improvement Area (BIA) levies for 2016:
6.1 Bridgeburg Station BIA Levy of $41,000
6.2 Ridgeway BIA Levy of $35,000
6.3 Crystal Beach BIA Levy of $9,931, and further

**PART 7**

**That:** Council approves the Town’s General Levy of $___________ comprised of base budget of $23,110,534 and supplementary budget of $___________ and directs staff to submit the related By-law for approval on February 22, 2016, and further

**PART 8**

**That**: Council excludes capital asset amortization of $5,922,200 from the 2016 General Levy Operating Budget.

CBC-07-2016 - 2016 Operating Budget - combined

## 6. Adjournment

# PORT BEGINS BUDGET TALKS

Posted by Jamie Lee on Wednesday, December 18th, 2013

Maryanne Firth / Welland Tribune

PORT COLBORNE - 'Tis the season for budget deliberations.

Lakeside city councillors began chipping away at Port Colborne's 2014 budget Monday night, beginning the process with a staff-recommended 3.92% tax increase.

By the end of the meeting, with both additions and subtractions made, the increase sat at 4.45%.

But talks surrounding the city's budget have only just begun, stressed Mayor Vance Badawey, who would like to see an increase closer to the rate of inflation, which is generally under 2%.

The budget moved upward as councillors added $61,000 for transit, including Saturday service and extended hours, and $98,000 for tree programs, including removal of dying trees and those impacted by the emerald ash borer, tree replacement and a partnership with residents to see dying trees on private property removed.

The tree issue has always been important, Badawey said, but the November fatality, in which a woman was struck by a falling tree while driving her car down Fielden Ave., has left it on everyone's minds.

"It impresses the importance of continuing our due diligence with the tree program," he said.

One of the biggest budget savings came from the city's economic development and tourism department. After the departure of economic development officer Stephen Thompson several months ago, the position has remained vacant. The role has since been split, with certain responsibilities being taken on by the mayor's office, existing planning and development staff and contracted staff.

"It has a positive impact on the budget because we're using existing resources," Badawey said. The changes mean a $147,000 savings, he added.

The city intends to hire a new economic development officer in the spring to fill the altered role.

"Economic development works through my office on a daily basis," Badawey said, adding the transition with the vacant position has been "seamless" due to the hard work of staff.

The city is also hoping to find about $100,000 in savings by creating a self-sustaining business model for Sugarloaf Harbour Marina, which staff is expected to present some time in the new year, Badawey said.

Budget deliberations will continue on Jan. 6 at 5:30 p.m. in council chambers.


## NEWS ARCHIVE

Search Clear

Bridge 21 (Clarence Street) Closed
The St. Lawrence Seaway Management Corporation
J. Lee Wed Dec 14th, 2016

Leading Women - Leading Girls Building Commun…
2017 Call for Nominations
Michelle Cuthbert Wed Nov 30th, 2016

Sale of Blackberry Cell Phones
City of Port Colborne
J. Lee Mon Nov 21st, 2016

Province invests in Allied Marine expansion
Laura Barton / Tribune Staff
J. Lee Wed Nov 9th, 2016

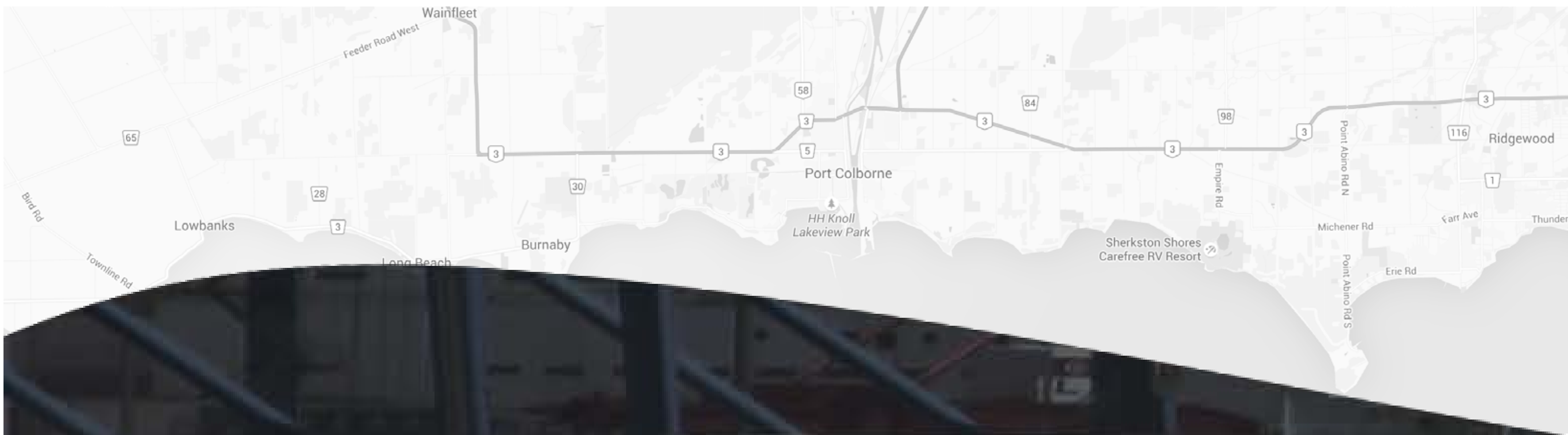
Remembrance Day
Friday, November 11, 2016
J. Lee Tue Nov 8th, 2016

[Bridge 21 (Clarence Street) Closure](#)
The St. Lawrence Seaway Management Corporation
J. Lee Tue Nov 8th, 2016

[Bridge 21 (Clarence Street) Closure](#)
The St. Lawrence Seaway Management Corporation
J. Lee Mon Oct 24th, 2016

[Bridge 21 (Clarence Street) Closure](#)
The St. Lawrence Seaway Management Corporation
J. Lee Mon Oct 17th, 2016






CITY OF PORT
COLBORNE

66 Charlotte Street,
Port Colborne
Ontario, L3K 3C8

(905) 835-2900

# Tab 7 – Productivity Summary

| Cost Savings / Productivity Improvements | Savings Included in 2-JB | References to Evidence | Value to Customer |
|---|---|---|---|
| Port Colborne Service Centre Closure | 55,000 | E4/T2/S2/p3 | - Cost Reduction |
| Regulatory Staffing | 100,000 | E4/T2/S2/p3 | - Cost Reduction |
| Customer Service Staffing and Charge-Outs | 162,000 | E4/T2/S2/p4 | - Cost Reduction |
| Field Engineering / Mobile Computing / Electronic Mapping | N/A | E1/T1/S1/p22-23<br>E1/T1/S2/AppA/p16<br>E2/T2/S1/AppA/p29<br>E2/T2/S1/AppA/p56 | - Improved efficiency |
| Line Loss Reduction | N/A | E1/T1/S2/p23-24<br>E2/T2/S1/AppA/p29<br>2-Staff-25 | - Considered in evaluation of alternatives for capital projects<br>- Reduced cost of power pass-through |
| Standardized Designs | N/A | E1/T1/S2/p23<br>E2/T2/S1/AppA/p29 | - Improved efficiency |
| Distribution Automation | N/A | E1/T1/S2/p23<br>E1/T3/S1/p13<br>E2/T2/S1/AppA(multiple) | - Long-term reduction in outage response costs |
| Asset Management | N/A | E2/T2/S1/AppA/p39-46<br>E2/T2/S1/AppA/AppM | - Optimized asset lifecycle costs<br>- Improved alternative evaluation for capital projects |

# Tab 8 – Adjusted PEG Econometric Model

Summary

The most recent version of the OEB's Benchmarking Forecast Model (the "Model") filed by CNPI is dated November 7, 2016, and was filed in conjunction with CNPI's Technical Conference Undertakings. In that version of the Model CNPI updated the input for WACC as a result of the OEB's recently published cost of capital parameters, and the accompanying narrative discussed an issue associated with the mismatch between costs and revenues associated with Other Revenue accounts (i.e. accounts 4325, 4330, and 4375).

In conjunction with these Hearing Materials, CNPI has filed a further update to the Model (the "Adjusted Model") with further updates to the WACC input and an analysis that provides further detail on the Other Revenue issue, as detailed below. In addition, CNPI has populated the Adjusted Model to include forecasts for the 2018-2021 IRM years.

Update to WACC

All prior versions of the Model filed by CNPI have included values for the WACC input specific to CNPI, or a CNPI-specific placeholder for forecasted WACC, pending updates to the OEB's cost of capital parameters. The Adjusted Model corrects this oversight, using a value the WACC input reflecting OEB-deemed rates, which is consistent with historical PEG benchmarking models.

Adjustments for Other Revenue

In conjunction with the November 7, 2016 update to the Model, CNPI filed additional notes describing the impact of the model including certain costs associated with the generation of Other Revenue (i.e. accounts 4325, 4330, and 4375), without including the offsetting revenue, or any other variables to account for these costs. CNPI later agreed to an increase of $100,000 to Other Revenue in its Partial Settlement Agreement (to the direct benefit of CNPI's ratepayers), however CNPI's benchmarking results did not change and no updates to the Model were required as a result of Other Revenue accounts being excluded. In the event that these costs affected all LDC's in similar proportions, or were addressed through input variables, then no further adjustment would be required. As outlined in Tab 9 of these Hearing Materials however, CNPI is an outlier with respect to other LDC's in terms of Other Revenue generated through services to its affiliates and associated companies. Historically, the PEG model used amounts for gross asset additions for CNPI based on RRR filings that failed to account for CNPI's historical practice of removing the costs of certain shared assets for rate-making purposes. As described at Exhibit 2, Tab 1, Schedule 1 of the Application (and further documented in 2-Staff-18), in accordance with Board Staff's preference in API's previous Cost of Service Application (EB-2014-0055), a different approach was taken such that the amounts are no longer removed. In lieu of removing the costs associated with shared assets for ratemaking purposes, CNPI has included shared IT and equipment charges as revenue offsets, as reflected in Other Revenue accounts.

In order to illustrate the impact of this issue on CNPI's benchmarking results, the Adjusted Model includes an analysis of the impact of the Other Revenue offset. CNPI has included an adjustment that considers the net total of accounts 4325, 4330, and 4375 (i.e. the accounts associated with IT services provided to affiliates and associates) as an offset to the total actual cost calculated by the Model. The Adjusted Model retains the results of the OEB's original model, but also presents a set of results as adjusted for the Other Revenue proxy described above.

The results shown in the Adjusted Model would place CNPI in the average/expected cost range of -10% to +10% (i.e. Group III). CNPI is not suggesting to be assigned the cohort 3 stretch factor for the upcoming IRM, however the analysis reveals a significant issue with trying to apply the PEG model to a cost of service application.

# Summary of Cost Benchmarking Results (Adjusted)

## Canadian Niagara Power Inc.

| | Cost Benchmarking Summary | 2015 (History) | 2016 (Bridge) | 2017 (Test Year) | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|
| A | Actual Total Cost | 22,334,375 | 23,534,557 | 23,992,198 | 24,800,661 | 25,575,451 | 26,390,794 | 27,280,821 |
| B | Other Revenue Offset (Accts 4325/4330/4375) | | | 1,456,194 | 1,456,194 | 1,456,194 | 1,456,194 | 1,456,194 |
| C = A - B | Revised Actual Cost | | | 22,536,004 | 23,344,467 | 24,119,257 | 24,934,600 | 25,824,627 |
| D | Predicted Total Cost | 19,620,562 | 20,204,249 | 20,444,658 | 21,207,353 | 22,026,055 | 22,857,913 | 23,725,499 |
| E = A - D | Difference | 2,713,813 | 3,330,308 | 3,547,540 | 3,593,307 | 3,549,396 | 3,532,881 | 3,555,321 |
| F = C - D | Difference with Other Revenue Offset | | | 2,091,346 | 2,137,113 | 2,093,202 | 2,076,687 | 2,099,127 |
| **G = LN(A/D)** | **Percentage Difference (Cost Performance)** | **13.0%** | **15.3%** | **16.0%** | **15.65%** | **14.94%** | **14.37%** | **13.96%** |
| **H = LN(C/D)** | **Percentage Difference (Cost Performance - With Other Revenue Offset)** | | | **9.7%** | **9.6%** | **9.1%** | **8.7%** | **8.5%** |
| | Three-Year Average Performance | | | 14.7% | 15.64% | 15.53% | 14.99% | 14.43% |
| | Three-Year Avg (With Other Revenue Offset) | | | | | 9.47% | 9.13% | 8.75% |
| | **Stretch Factor Cohort** | | | | | | | |
| | Annual Result | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| | Annual Result (with Other Revenue Offset) | | | 3 | 3 | 3 | 3 | 3 |
| | Three Year Average | | | 4 | 4 | 4 | 4 | 4 |
| | Three Year Average (with Other Revenue Offset) | | | | | 3 | 3 | 3 |

# Tab 9 – Analysis of LDC Other Revenues

## 2015 OEB Yearbook - Other Income Analysis

| LDC | Revenues from Service - Distribution (A) | Other Income (B) | C = B / (A + B) |
|---|---|---|---|
| E.L.K. Energy Inc. | 3,437,525 | 613,774 | 15.2% |
| Canadian Niagara Power Inc. | 18,555,741 | 1,857,805 | 9.1% |
| Innpower Corporation | 9,513,573 | 583,728 | 5.8% |
| Fort Frances Power Corporation | 1,929,536 | 109,107 | 5.4% |
| EnWin Utilities Ltd. | 50,363,775 | 2,663,278 | 5.0% |
| Kenora Hydro Electric Corporation Ltd. | 2,957,765 | 152,719 | 4.9% |
| Cooperative Hydro Embrun Inc. | 808,657 | 40,276 | 4.7% |
| PowerStream Inc. | 176,741,188 | 8,553,825 | 4.6% |
| Atikokan Hydro Inc. | 1,441,417 | 66,952 | 4.4% |
| Centre Wellington Hydro Ltd. | 3,429,077 | 158,668 | 4.4% |
| Welland Hydro-Electric System Corp. | 9,310,929 | 387,883 | 4.0% |
| Enersource Hydro Mississauga Inc. | 128,985,693 | 5,216,195 | 3.9% |
| Hydro Ottawa Limited | 164,726,438 | 6,541,125 | 3.8% |
| Cambridge and North Dumfries Hydro Inc. | 28,132,986 | 1,111,864 | 3.8% |
| West Coast Huron Energy Inc. | 2,422,418 | 89,029 | 3.5% |
| Haldimand County Hydro Inc. | 12,718,238 | 463,382 | 3.5% |
| Hearst Power Distribution Company Limited | 1,412,227 | 49,305 | 3.4% |
| Midland Power Utility Corporation | 3,928,049 | 135,393 | 3.3% |
| Guelph Hydro Electric Systems Inc. | 30,112,381 | 1,031,146 | 3.3% |
| Ottawa River Power Corporation | 4,413,906 | 144,830 | 3.2% |
| Halton Hills Hydro Inc. | 10,321,449 | 336,164 | 3.2% |
| Burlington Hydro Inc. | 30,461,885 | 923,261 | 2.9% |
| Sioux Lookout Hydro Inc. | 1,946,621 | 57,510 | 2.9% |
| Bluewater Power Distribution Corporation | 22,152,629 | 653,487 | 2.9% |
| Oakville Hydro Electricity Distribution Inc. | 38,292,999 | 1,006,322 | 2.6% |
| Milton Hydro Distribution Inc. | 16,790,419 | 437,589 | 2.5% |
| Lakeland Power Distribution Ltd. | 8,416,579 | 191,160 | 2.2% |
| Horizon Utilities Corporation | 113,280,688 | 2,434,343 | 2.1% |
| St. Thomas Energy Inc. | 7,360,974 | 153,437 | 2.0% |
| PUC Distribution Inc. | 18,606,892 | 382,803 | 2.0% |
| Niagara Peninsula Energy Inc. | 31,390,515 | 592,125 | 1.9% |
| Oshawa PUC Networks Inc. | 20,877,077 | 391,929 | 1.8% |
| Hydro One Networks Inc. | 1,358,955,905 | 24,872,713 | 1.8% |
| Hydro 2000 Inc. | 548,480 | 10,016 | 1.8% |
| Espanola Regional Hydro Distribution Corporation | 1,850,875 | 32,545 | 1.7% |
| Tillsonburg Hydro Inc. | 3,625,998 | 58,684 | 1.6% |
| Northern Ontario Wires Inc. | 3,140,942 | 49,606 | 1.6% |
| Rideau St. Lawrence Distribution Inc. | 2,727,826 | 39,209 | 1.4% |
| Brantford Power Inc. | 17,522,818 | 214,719 | 1.2% |
| Lakefront Utilities Inc. | 4,645,221 | 56,259 | 1.2% |
| Festival Hydro Inc. | 12,959,553 | 148,603 | 1.1% |
| Thunder Bay Hydro Electricity Distribution Inc. | 20,847,752 | 226,320 | 1.1% |

## 2015 OEB Yearbook - Other Income Analysis

| LDC | Revenues from Service - Distribution (A) | Other Income (B) | C = B / (A + B) |
|---|---|---|---|
| Westario Power Inc. | 10,035,675 | 108,868 | 1.1% |
| Veridian Connections Inc. | 53,436,485 | 555,367 | 1.0% |
| COLLUS PowerStream Corp. | 7,013,970 | 70,642 | 1.0% |
| Greater Sudbury Hydro Inc. | 23,966,012 | 231,307 | 1.0% |
| Essex Powerlines Corporation | 14,327,450 | 127,215 | 0.9% |
| Toronto Hydro-Electric System Limited | 646,664,428 | 5,607,211 | 0.9% |
| Wasaga Distribution Inc. | 4,167,061 | 27,848 | 0.7% |
| Hydro Hawkesbury Inc. | 1,678,022 | 10,906 | 0.6% |
| Grimsby Power Incorporated | 4,593,355 | 20,078 | 0.4% |
| Niagara-on-the-Lake Hydro Inc. | 4,903,115 | 19,043 | 0.4% |
| Wellington North Power Inc. | 2,473,576 | - 1,663 | -0.1% |
| Hydro One Brampton Networks Inc. | 71,816,392 | - 359,882 | -0.5% |
| Peterborough Distribution Incorporated | 15,396,137 | - 116,937 | -0.8% |
| Orangeville Hydro Limited | 5,077,192 | - 94,799 | -1.9% |
| Algoma Power Inc. | 23,134,438 | - 532,613 | -2.4% |
| London Hydro Inc. | 68,353,973 | - 1,983,774 | -3.0% |
| Woodstock Hydro Services Inc. | 8,518,884 | - 267,268 | -3.2% |
| Chapleau Public Utilities Corporation | 858,049 | - 29,681 | -3.6% |
| Erie Thames Powerlines Corporation | 10,209,821 | - 431,231 | -4.4% |
| Entegrus Powerlines Inc. | 20,212,690 | - 865,344 | -4.5% |
| Whitby Hydro Electric Corporation | 23,030,983 | - 1,151,853 | -5.3% |
| North Bay Hydro Distribution Limited | 12,792,738 | - 690,243 | -5.7% |
| Kingston Hydro Corporation | 12,346,347 | - 771,727 | -6.7% |
| Newmarket-Tay Power Distribution Ltd. | 17,454,205 | - 1,179,092 | -7.2% |
| Renfrew Hydro Inc. | 1,932,872 | - 134,659 | -7.5% |
| Orillia Power Distribution Corporation | 8,574,569 | - 621,871 | -7.8% |
| Kitchener-Wilmot Hydro Inc. | 39,624,846 | - 3,547,234 | -9.8% |
| Brant County Power Inc. | 6,125,519 | - 577,011 | -10.4% |
| Waterloo North Hydro Inc. | 34,531,174 | - 3,325,043 | -10.7% |

**2015-2017 Test Year Other Revenue Analysis**

| | Test Year | Distribution Revenue | Other Revenue | Total Revenue | % Other Revenue |
|---|---|---|---|---|---|
| Hearst | 2015 | 1,058,101 | 229,503 | 1,287,603 | 17.8% |
| Canadian Niagara Power | 2017 | 19,401,592 | 2,548,193 | 21,949,785 | 11.6% |
| Wasaga | 2016 | 3,988,244 | 474,377 | 4,462,621 | 10.6% |
| Milton | 2016 | 16,306,076 | 1,930,835 | 18,236,911 | 10.6% |
| InnPower | 2017 | 11,178,412 | 1,207,121 | 12,385,532 | 9.7% |
| North Bay | 2015 | 11,793,143 | 1,173,934 | 12,967,077 | 9.1% |
| Halton Hills | 2016 | 9,953,991 | 959,144 | 10,913,135 | 8.8% |
| Lakefront | 2017 | 4,368,508 | 419,585 | 4,788,092 | 8.8% |
| Guelph | 2016 | 29,528,324 | 2,307,201 | 31,835,525 | 7.2% |
| Brantford | 2017 | 17,098,955 | 1,315,000 | 18,413,955 | 7.1% |
| Northern Ontario Wires | 2017 | 3,563,567 | 268,918 | 3,832,485 | 7.0% |
| London | 2017 | 67,853,776 | 4,964,164 | 72,817,940 | 6.8% |
| Atikokan | 2017 | 1,415,718 | 102,770 | 1,518,488 | 6.8% |
| Festival | 2015 | 10,455,129 | 755,699 | 11,210,828 | 6.7% |
| Hydro Ottawa | 2016 | 163,347,677 | 11,696,988 | 175,044,665 | 6.7% |
| Entegrus | 2016 | 17,859,875 | 1,261,521 | 19,121,396 | 6.6% |
| St. Thomas | 2015 | 7,450,543 | 512,644 | 7,963,187 | 6.4% |
| Ottawa River | 2016 | 4,347,469 | 284,010 | 4,631,479 | 6.1% |
| Powerstream | 2017 | 199,501,459 | 12,718,312 | 212,219,771 | 6.0% |
| Oshawa | 2015 | 20,975,186 | 1,319,113 | 22,294,299 | 5.9% |
| Hydro One Brampton | 2015 | 68,017,986 | 4,126,589 | 72,144,575 | 5.7% |
| Grimsby | 2016 | 5,252,850 | 301,588 | 5,554,439 | 5.4% |
| Niagara Peninsula | 2015 | 28,665,191 | 1,602,522 | 30,267,713 | 5.3% |
| Welland | 2017 | 10,106,284 | 530,050 | 10,636,334 | 5.0% |
| Horizon | 2015 | 108,649,524 | 5,677,916 | 114,327,440 | 5.0% |
| Thunder Bay | 2017 | 23,996,075 | 1,247,451 | 25,243,526 | 4.9% |
| Renfrew | 2017 | 2,094,391 | 107,550 | 2,201,941 | 4.9% |
| Chapleau | 2016 | 847,617 | 43,505 | 891,122 | 4.9% |
| Wellington North | 2016 | 2,539,073 | 130,105 | 2,669,178 | 4.9% |
| Kingston | 2016 | 11,523,232 | 576,998 | 12,100,230 | 4.8% |
| Waterloo | 2016 | 33,756,728 | 1,223,596 | 34,980,324 | 3.5% |
| Algoma | 2015 | 22,816,181 | 466,758 | 23,282,939 | 2.0% |

| | |
|---|---|
| **Average** | **7.0%** |
| **Weighted Average** | **6.2%** |

# Tab 10 – Board Staff Report on Community Meetings

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

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

Ontario

**BY E-MAIL**

November 11, 2016

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

**Re: Canadian Niagara Power Inc.**
**Application for Rates**
**Board File Number EB-2016-0061**

Please find attached the Summary of Community Engagement by OEB Staff for this application.

*Original Signed By*

Martin Davies
Project Advisor, Rates
Major Applications

Attachment

cc: Parties to EB-2016-0061

Ontario

# Ontario Energy Board
# Commission de l'énergie de l'Ontario

# SUMMARY OF COMMUNITY ENGAGEMENT BY OEB STAFF

## EB-2016-0061

## CANADIAN NIAGARA POWER INC.

**Application for 2017 Rates: Community Meetings**

**November 9, 2016**

## TABLE OF CONTENTS

# 1 INTRODUCTION AND SUMMARY

This is an OEB staff report on the community meetings held in conjunction with Canadian Niagara Power Inc.'s (CNPI) 2017 cost of service rate application. It will be placed on the public record of the OEB hearing of this application along with copies of written presentations made at the meetings and all letters of comment for consideration by the OEB in determining whether or not to grant the application by CNPI.

Further to the Notice of Application, the OEB hosted two community meetings regarding CNPI's application on September 13, 2016 in Port Colborne, Ontario and September 14, 2016 in Gananoque, Ontario. This report provides a summary of the events.

## 1.1 Port Colborne Ontario

The Port Colborne meeting was held at the Vale Health and Wellness Centre from 6:30 p.m. to 8:30 p.m.. Approximately 110 customers attended the meeting to hear presentations from OEB staff and CNPI. Prior to the presentations, OEB and CNPI staff were available to informally talk to attendees and answer questions. Councillor Marina Butler and Mr. John Robinson presented prepared remarks. OEB and CNPI representatives responded to questions from attendees during and following the presentations.

The following OEB staff and CNPI representatives attended the meeting:

<u>OEB Staff</u>

Ljuba Djurdjevic
Ceiran Bishop
Sylvia Kovesfalvi
Andrew Bodrug
Martin Davies

CNPI

Jie Han, VP Operations
Glen King, VP Finance and CFO
Kristine Carmichael, Director of Corporate and Customer Services
Greg Beharriel, Manager, Regulatory Affairs
Rodney Barber, Regulatory Analyst
Taylor Wilson, Energy Advisor
Courtney Bonito, Customer Service Supervisor
Jennifer Fretz-Joseph, Supervisor, IT Business Support

## 1.2 Gananoque Ontario

The Gananoque Meeting took place at the Royal Canadian Legion Branch 92 from 5:30pm to 8:30pm and was attended by approximately 100 customers. Prior to the presentations, OEB and CNPI staff were available to answer informal questions from attendees. OEB staff and CNPI representatives gave formal presentations and prepared comments were provided by customers Barbara Jones and Bill Webster. OEB and CNPI representatives responded to questions from attendees during and following the presentations.

The following OEB staff and CNPI representatives attended the meeting:

OEB Staff

Kristi Sebalj
Ceiran Bishop
Sylvia Kovesfalvi
Andrew Bodrug
Martha McOuat

CNPI:

Jie Han, VP, Operations
Kristine Carmichael, Director of Corporate and Customer Services
Greg Beharriel, Manager, Regulatory Affairs
Rodney Barber, Regulatory Analyst
Jennifer Fretz-Joseph, Supervisor, IT Business Support
Michael O’Reilly, General Manager, Eastern Ontario Power

# 2 THE PROCESS

The OEB convenes community meetings in the service territories of local distribution companies that have applied to the OEB to change their rates through a cost of service proceeding.

Community meetings are part of the OEB's process of reviewing a rate application . The OEB has established a Customer Engagement Framework to ensure that the perspectives of customers served by rate-regulated entities are considered in the OEB's decision making process. .

The meetings are hosted by OEB staff in order to inform customers about the role of the OEB in rate-setting and the processes involved. OEB representatives explain the various ways that customers can become involved in the adjudicative process. Customers attending the meetings are given the opportunity to express their concerns directly to the OEB through online comments on the computers provided or by filling in a comment form.

To assist customers in better understanding the application, the utility is invited to make a presentation explaining its proposals for capital, operations and other spending that result in the requested rate change. Customers and municipal officials are also invited to make presentations outlining their thoughts on the utility's proposals.

Following the presentations, customers have the opportunity to ask questions of the OEB and the utility about the application and the regulatory process. The issues raised by customers in the community meetings are documented and used by OEB staff in reviewing the application, asking interrogatories and making submissions to the OEB panel hearing and deciding the application.

# 3 SUMMARY OF THE MEETINGS

## 3.1 Port Colborne

In addition to the OEB and CNPI presentations (attached as schedules A and B, respectively), two customers also provided comments.

Councillor Marina Butler asked CNPI to explain the extent to which it had taken steps to find efficiencies in its operations and consider asset optimization strategies such as deeming some of its transmission infrastructure as distribution facilities. She expressed concerns regarding the movement of CNPI from the lowest rates in the Niagara peninsula to the highest in the last 15 years. She ended her presentation by questioning if CNPI has the ability to reduce rates for the people they serve.

Mr. John Robinson's presentation encouraged CNPI to consider ways to improve customer service by making its customer-facing activities friendlier to seniors, who represent a large portion of CNPI's customer base. Mr. Robinson submitted that seniors likely prefer in-person customer service rather than by electronic means. Accordingly, Mr. Robinson encouraged CNPI to re-open a customer service office in Port Colborne in order to better serve customers in that area.

Significant portions of the audience expressed dissatisfaction with many aspects of provincial energy policy and CNPI's application. Many attendees reported that they could not afford to pay for any further rate increases.

**Specific Issues Raised**

- CNPI's application – questions regarding current and future capital expenditures, OM&A, especially wages and salaries, customer service and particularly the associated bill impacts
- Electricity prices – general concerns regarding affordability, as well as provincial energy policy, including the partial sale of Hydro One
- The potential effectiveness of the government's rate relief program – 8% off the HST, rural rate rebates and additional support for business
- Renewable generation – exports of below-cost power to New York, the status of development of energy storage, the cost of renewable energy programs
- OPG – salary levels and nuclear cost overruns
- Electricity sector compensation
- Consideration of compensation in OEB's review of CNPI's application

- Extent of OEB oversight of increases in the cost of power, the regulated price plan, time of use rates, and the global adjustment.

## 3.2 Gananoque

Following the presentations by OEB staff and CNPI (Schedule C), there were two brief presentations from customers.

Barbara Jones stated that people were doing all they could to reduce their electricity costs and requested that the OEB more closely monitor service providers to ensure increased reliability and improved efficiency. Ms. Jones' comments have been attached to this document as Schedule D.

Bill Webster requested that the OEB should deny any increase in rates until CNPI addressed reliability issues.

Bruce Davis provided a handout with five suggestions for actions that could be taken to improve the energy situation by the Town of Gananoque and CNPI. These included funding for the promotion of generation and green energy solutions, developing a database of vulnerable citizens needing aid during power outages and securing access to the local power plant and dams. The handout has been attached to this document as Schedule E.

The primary focus of attendees' questions was the recent and ongoing power outages experienced in the area and the perception that CNPI and Hydro One had not undertaken sufficient action to resolve the problems.

**Specific Issues Raised**

- CNPI's application – questions regarding the inclusion of spending to address reliability issues; lack of segregation of Gananoque reliability data within the application; administration spending levels.
- CNPI efforts to engage Hydro One to address reliability issues
- Mutual aid agreements with neighbouring utilities to reduce response time during outages
- Overall efficiency levels of CNPI as compared with other utilities in the province, and how the OEB monitors and enforces efficiency and performance.

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## Tab 11 – Summary of Port Colborne Customer Sessions

Summary of Participation in Port Colborne “Your Kilowatt Hour” Events

Background:

Recent Community Day sessions revealed that customers in locations where CNPI does not have a local office, would like the opportunity to meet with a CNPI representative to speak face to face. As a result of this feedback, CNPI has launched a pilot program called ‘Your Kilowatt Hour’ where a CNPI representative and a Conservation Specialist spend one day a month meeting face to face with customers.

Marketing:

These sessions were promoted the following channels:

- Newspaper ads
- Call blasts to each home in the service territory
- Website
- Social media, Twitter and Facebook
- Posted session information and agencies throughout Port Colborne

Customers were asked to call in and schedule appointments. Appointments were scheduled every half hour from 10:00 a.m. to 3:00 p.m. on each day.

| | |
|---|---|
| October 7, 2016 | 3 customers attended |
| November 18, 2016 | 10 customers attended |
| December 9, 2016 | 6 customers attended, 3 did not show up for appointment |

Results:

Overall results and feedback from customers was very positive. Sessions will continue on a bi-monthly basis in 2017 with a roll out to Eastern Ontario Power service territory on a quarterly basis.

# Tab 12 – EOP Reliability Presentation

Eastern Ontario Power

A FORTIS ONTARIO Company

# Main Supply Improvement Options

# Recent EOP Reliability

| Eastern Ontario Power System Reliability Index | | | | |
|---|---|---|---|---|
| **YEAR** | **EOP Internal System** | | **EOP Loss of Supply** | |
| | SAIDI | SAIFI | SAIDI | SAIFI |
| **2011** | 1.99 | 1.52 | 0.00 | 0.00 |
| **2012** | 4.79 | 4.39 | 0.00 | 0.00 |
| **2013** | 4.00 | 3.45 | 0.00 | 0.00 |
| **2014** | 1.64 | 2.09 | 0.01 | 0.00 |
| **2015** | 1.01 | 0.59 | 23.02 | 2.29 |
| **2016 YTD** | 1.23 | 1.08 | 16.91 | 4.81 |

SAIDI = total hours of outages (Duration) in each year, for average customer

SAIFI = number of outages (Frequency) in each year, for average customer

# Recent EOP Loss-of-Supply Outages

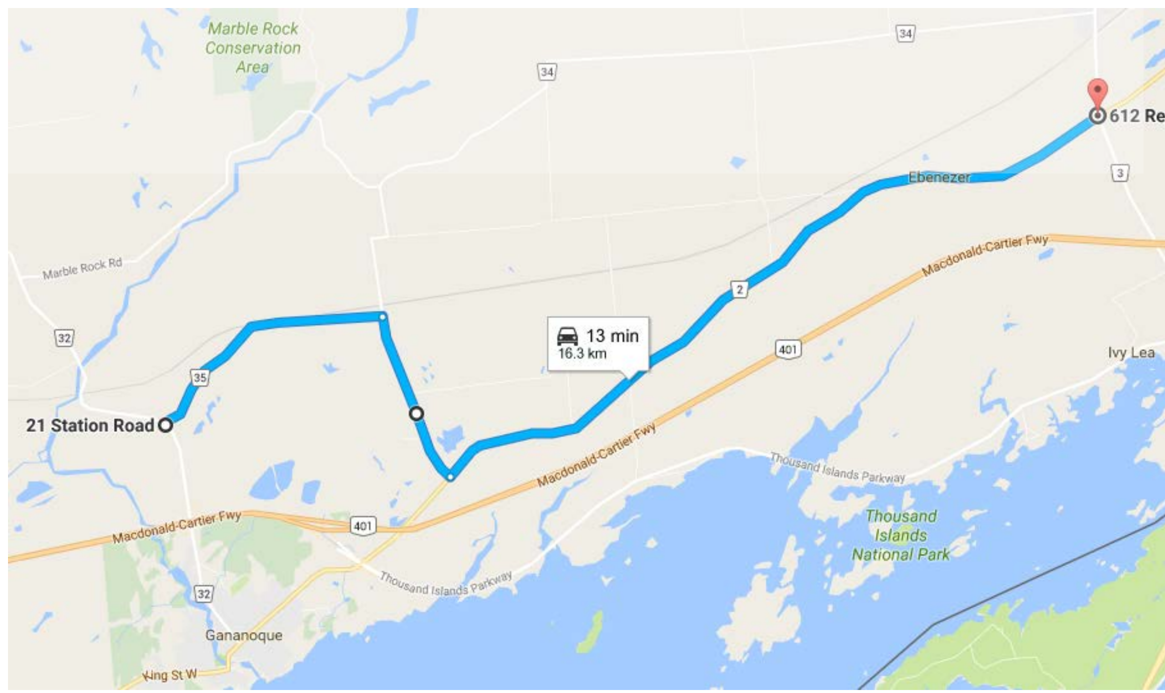
| Description | Date | Time | Duration (hours) |
|---|---|---|---|
| Pole fire on HONI 3M8 44kV feeder | 2015-Feb-04 | 1:00 PM | 9.20 |
| Fire @ HONI Frontenac TS (Source of 44kV) | 2015-Oct-27 | 9:22 AM | 11.17 |
| HONI 44kV line down during very high winds | 2016-Jan-10 | 6:30 PM | 3.08 |
| Vehicle struck HONI/EOP Joint Use pole, John F Scott Rd | 2016-Mar-27 | 10:15 AM | 3.25 |
| Vehicle struck HONI 44kV pole, Joyceville Rd @ Middle Rd | 2016-May-26 | 6:30 PM | 1.58 |
| Forced outage to isolate HONI 44kV pole after car accident | 2016-Jun-20 | 12:30 PM | 0.33 |
| Pole fire on HONI / EOP Joint Use pole, John F Scott Rd | 2016-Aug-10 | 7:17 AM | 9.47 |
| **Total for 7 Events** | | | **38.08** |

# Recent steps…

- Sept 7: “Lets talk Power” meeting by Town of Gananaque (TOG)
- Sept 14: OEB organized Customer Engagement meeting
- Sept 15: HONI and CNPI met to identify potential technical solutions
- Sept 16: TOG, Provincial MPP, Federal MP, Hydro One Networks (HONI) and CNPI met to discuss possible solutions.
  - HONI committed to complete feasibility study by November 15. This was completed on-time.
  - CNPI committed to make recommendation to TOG based on HONI study and CNPI internal discussion (This session!).

# Option 1: Construct Redundant 44kV Supply from Brockville

- Hydro One Networks (HONI) would construct 16.3km of 44kV line from end of legacy HONI M2 feeder (from Brockville) to connect to EOP Main Substation on Hwy 32, plus a voltage regulator station.
- Project would be done in 2019 at earliest
- Estimated cost:
  - HONI $10.75M (± 50%)
  - EOP $750k (± 50%)



# Option 1: Construct Redundant 44kV Supply from Brockville

**Pros**

- Completely independent source using different geographic route
  - Minimal chance of both sources being unavailable at the same time

**Cons**

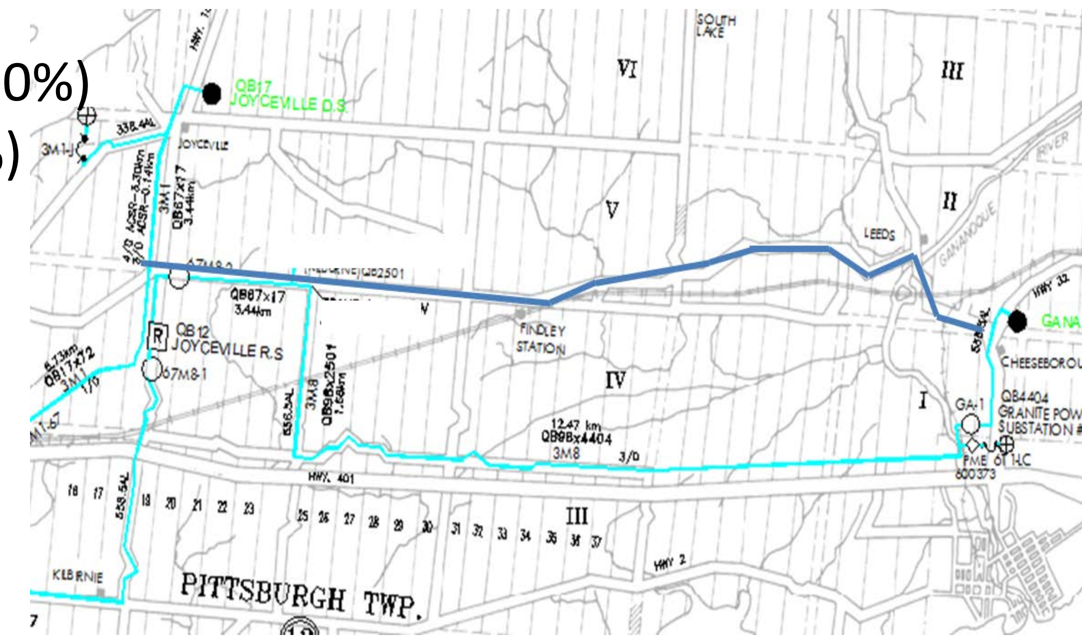
- Very Expensive:
  - Hydro One estimates project costs at **$10.75M (± 50%)**
    - Hydro One expects EOP to make a full contribution
  - EOP integration cost estimated at **$750k (± 50%)**
- Will not be built before 2019 at earliest
  - HONI requires 24 months <u>after</u> our commitment

# Option 1: Impact on Recent Outages

| Description | Date | Time | Actual Duration (hours) | Option Impact? | Likely 'New' Duration (hours) |
|---|---|---|---|---|---|
| Pole fire on HONI 3M8 44kV feeder | 2015-Feb-04 | 1:00 PM | 9.20 | **Yes** | **1.00** |
| Fire @ HONI Frontenac TS (Source of 44kV) | 2015-Oct-27 | 9:22 AM | 11.17 | **Yes** | **1.00** |
| HONI 44kV line down during very high winds | 2016-Jan-10 | 6:30 PM | 3.08 | **Yes** | **1.00** |
| Vehicle struck HONI/EOP Joint Use pole, John F Scott Rd | 2016-Mar-27 | 10:15 AM | 3.25 | **Yes** | **1.00** |
| Vehicle struck HONI 44kV pole, Joyceville Rd @ Middle Rd | 2016-May-26 | 6:30 PM | 1.58 | **Yes** | **1.00** |
| Forced outage to isolate HONI 44kV pole after car accident | 2016-Jun-20 | 12:30 PM | 0.33 | **No** | **0.33** |
| Pole fire on HONI / EOP Joint Use pole, John F Scott Rd | 2016-Aug-10 | 7:17 AM | 9.47 | **Yes** | **1.00** |
| **Total for 7 Events** | | | **38.08** | | **6.33** |

# Option 2: Extend second 44kV Supply from Frontenac TS (Kingston)

- This would require Hydro One Networks (HONI) to extend an existing 44kV line from Joyceville Rd  14km to EOP main substation on Hwy 32, plus a voltage regular station.
- Project would likely be done in 2018 at earliest
  - 18 months after our commitment
- Estimated cost:
  - HONI $6.00M (± 50%)
  - EOP $750k (± 50%)



# Option 2: Extend second 44kV Supply from Frontenac TS (Kingston)

**Pros**

- Second supply line using same route and same structures over much of its length
- Less expensive than Option 1
- Quicker to construct (by six months) than Option 1

**Cons**

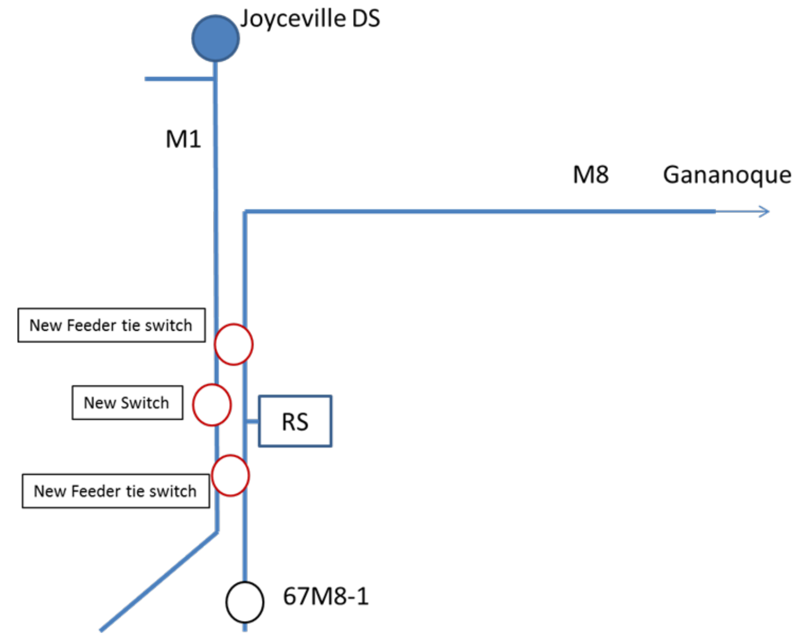
- Expensive:
  - Hydro One estimates project costs at **$6.00M (± 50%)**
    - Hydro One expects EOP to make a full contribution
  - EOP integration cost estimated at **$750k (±50%)**
- All of EOP would still be supplied by Frontenac TS
  - Common Source
- Approximately 14 km of 35 km for this route is on common poles (40%)
  - Loss of one of these poles means loss of supply
- Will not be built before 2018 at earliest
  - HONI requires 18 months from our commitment

# Option 2: Impact on Recent Outages

| Description | Date | Time | Actual Duration (hours) | Option Impact? | Likely 'New' Duration (hours) |
|---|---|---|---|---|---|
| Pole fire on HONI 3M8 44kV feeder | 2015-Feb-04 | 1:00 PM | 9.20 | **No** | **9.20** |
| Fire @ HONI Frontenac TS (Source of 44kV) | 2015-Oct-27 | 9:22 AM | 11.17 | **No** | **11.17** |
| HONI 44kV line down during very high winds | 2016-Jan-10 | 6:30 PM | 3.08 | **Yes** | **1.00** |
| Vehicle struck HONI/EOP Joint Use pole, John F Scott Rd | 2016-Mar-27 | 10:15 AM | 3.25 | **Yes** | **1.00** |
| Vehicle struck HONI 44kV pole, Joyceville Rd @ Middle Rd | 2016-May-26 | 6:30 PM | 1.58 | **Yes** | **1.00** |
| Forced outage to isolate HONI 44kV pole after car accident | 2016-Jun-20 | 12:30 PM | 0.33 | **No** | **0.33** |
| Pole fire on HONI / EOP Joint Use pole, John F Scott Rd | 2016-Aug-10 | 7:17 AM | 9.47 | **Yes** | **1.00** |
| **Total for 7 Events** | | | **38.08** | | **24.70** |

# Option 3: Install 44kV 'Tie' switches on Joyceville Rd

- This would require Hydro One Networks (HONI) to install new switchgear on Joyceville Rd to allow transfer from 3M8 to 3M1
- Conditional on available capacity on 3M1 at time of outage
  - EOP would be able to supply most load, even at peak
- Project would likely be done in 2017 at earliest
- Estimated cost: $106k (± 50%)



# Option 3: Install 44kV 'Tie' switches on Joyceville Rd

## Pros

- Inexpensive Compared to Option 1 and Option 2
  - Hydro One estimates project costs at **$106k* (± 50%)**
    - Hydro One expects EOP to make a full contribution
- Provides some feeder redundancy on supply line for approx. 60% of length of existing 44kV line
- Can be completed in 2017
  - HONI requires 6 months after our commitment

## Cons

- Does not address any issues on 'last 16km' of 44kV supply line
- Still only one source
  - Frontenac TS (Kingston)
- Still using common poles for 11km (30%) of supply length

*can be absorbed into CNPI rate base

# Option 3: Impact on Recent Outages

| Description | Date | Time | Actual Duration (hours) | Option Impact? | Likely 'New' Duration (hours) |
|---|---|---|---|---|---|
| Pole fire on HONI 3M8 44kV feeder | 2015-Feb-04 | 1:00 PM | 9.20 | **No** | **9.20** |
| Fire @ HONI Frontenac TS (Source of 44kV) | 2015-Oct-27 | 9:22 AM | 11.17 | **No** | **11.17** |
| HONI 44kV line down during very high winds | 2016-Jan-10 | 6:30 PM | 3.08 | **No** | **3.08** |
| Vehicle struck HONI/EOP Joint Use pole, John F Scott Rd | 2016-Mar-27 | 10:15 AM | 3.25 | **Yes** | **2.00** |
| Vehicle struck HONI 44kV pole, Joyceville Rd @ Middle Rd | 2016-May-26 | 6:30 PM | 1.58 | **No** | **1.58** |
| Forced outage to isolate HONI 44kV pole after car accident | 2016-Jun-20 | 12:30 PM | 0.33 | **No** | **0.33** |
| Pole fire on HONI / EOP Joint Use pole, John F Scott Rd | 2016-Aug-10 | 7:17 AM | 9.47 | **Yes** | **2.00** |
| **Total for 7 Events** | | | **38.08** | | **29.37** |

# Option 4: Rebuild 7.5 km of 44/26kV Joint Use (shared) Line on John F Scott Rd

- EOP and HONI work together to replace 7.5km of older pole line on John F Scott Rd.
  - This line is nearing end of useful service life
- EOP will use this opportunity to perform voltage conversions
  - Improved efficiency
- Project would likely be done in late early 2018
- HONI will transfer their line at their own cost (~$400k)
- Estimated cost to EOP:
  - Contribution to HONI $269k (± 50%)
  - EOP $433k (± 50%)
  - **TOTAL = $702k (±50%)**

# Option 4: Rebuild 7.5 km of 44/26kV Joint Use (shared) Line on John F Scott Rd

## Pros

- Replaces 7.5km of pole line that is nearing the end of useful life
- Eliminates asset condition-based outages on this section
- New stronger poles MAY withstand minor vehicular contacts
- Allows for some long-term system efficiencies (voltage conversion)

## Cons

- Moderate Cost:
  - Hydro One estimates project costs at **$669k (± 50%)**
    - Hydro One will absorb $400k
  - EOP estimated project cost is **$433k (± 50%)**
  - **Total cost estimate = $702k***
- Will not be built before late 2018 at earliest
  - HONI requires 9 months from our commitment

*can be absorbed into CNPI rate base

# Option 4: Impact on Recent Outages

| Description | Date | Time | Actual Duration (hours) | Option Impact? | Likely 'New' Duration (hours) |
|---|---|---|---|---|---|
| Pole fire on HONI 3M8 44kV feeder | 2015-Feb-04 | 1:00 PM | 9.20 | **Yes** | **0.00** |
| Fire @ HONI Frontenac TS (Source of 44kV) | 2015-Oct-27 | 9:22 AM | 11.17 | **No** | **11.17** |
| HONI 44kV line down during very high winds | 2016-Jan-10 | 6:30 PM | 3.08 | **No** | **3.08** |
| Vehicle struck HONI/EOP Joint Use pole, John F Scott Rd | 2016-Mar-27 | 10:15 AM | 3.25 | Not Likely | **3.25** |
| Vehicle struck HONI 44kV pole, Joyceville Rd @ Middle Rd | 2016-May-26 | 6:30 PM | 1.58 | Not Likely | **1.58** |
| Forced outage to isolate HONI 44kV pole after car accident | 2016-Jun-20 | 12:30 PM | 0.33 | **No** | **0.33** |
| Pole fire on HONI / EOP Joint Use pole, John F Scott Rd | 2016-Aug-10 | 7:17 AM | 9.47 | **Yes** | **0.00** |
| **Total for 7 Events** | | | **38.08** | | **19.42** |

# Comparison of all four Options

| | Description | Cost (±50%) | Reliability Improvements | Estimated SAIFI* | Estimated SAIDI* |
|---|---|---|---|---|---|
| - | Status Quo - Do nothing | $0 | Worst | 7.0 | 38.1hr |
| 1 | Build new 44kV line from Brockville | $11,250,000 | Good | 7.0 | 6.3hr |
| 2 | Extend second 44kV line from Frontenac TS (Kingston) | $6,500,000 | Fair | 7.0 | 24.7hr |
| 3 | Install new tie switches between two HONI 44kV Lines | $106,000 | Fair | 7.0 | 29.4hr |
| 4 | Rebuild 7.5km Joint-Use (shared) line – John F Scott Rd | $702,000 | Fair | 5.0 | 19.4hr |

* Assumes recent loss-of-supply events were to occur again exactly the same way as in the past

# Comparison of all four Options

| | Description | Cost (±50%) | Reliability Improvements | Estimated SAIFI* | Estimated SAIDI* |
|---|---|---|---|---|---|
| - | Status Quo - Do nothing | $0 | Worst | 7.0 | 38.1hr |
| 1 | Build new 44kV line from Brockville | $11,250,000 | Good | 7.0 | 6.3hr |
| 2 | Extend second 44kV line from Frontenac TS (Kingston) | $6,500,000 | Fair | 7.0 | 24.7hr |
| 3 | Install new tie switches between two HONI 44kV Lines | $106,000 | Fair | 7.0 | 29.4hr |
| 4 | Rebuild 7.5km Joint-Use (shared) line – John F Scott Rd | $702,000 | Fair | 5.0 | 19.4hr |

- Options 1 and 2 are very expensive for a customer base of 3600 customers. All investments would need to be fully recovered through contributions from the Town of Gananoque
- Option 3 is affordable, but only addresses a few of the recent loss-of-supply incidents
- Option 4 is affordable, and investment will have to be made in near future anyways

# What if EOP implemented Options 3 AND 4?

| Description | Date | Time | Actual Duration (hours) | Option Impact? | Likely 'New' Duration (hours) |
|---|---|---|---|---|---|
| Pole fire on HONI 3M8 44kV feeder | 2015-Feb-04 | 1:00 PM | 9.20 | **Yes** | **0.00** |
| Fire @ HONI Frontenac TS (Source of 44kV) | 2015-Oct-27 | 9:22 AM | 11.17 | **No** | **11.17** |
| HONI 44kV line down during very high winds | 2016-Jan-10 | 6:30 PM | 3.08 | **No** | **3.08** |
| Vehicle struck HONI/EOP Joint Use pole, John F Scott Rd | 2016-Mar-27 | 10:15 AM | 3.25 | **Yes** | **2.00** |
| Vehicle struck HONI 44kV pole, Joyceville Rd @ Middle Rd | 2016-May-26 | 6:30 PM | 1.58 | Not Likely | **1.58** |
| Forced outage to isolate HONI 44kV pole after car accident | 2016-Jun-20 | 12:30 PM | 0.33 | **No** | **0.33** |
| Pole fire on HONI / EOP Joint Use pole, John F Scott Rd | 2016-Aug-10 | 7:17 AM | 9.47 | **Yes** | **0.00** |
| **Total for 7 Events** | | | **38.08** | | **18.17** |

# Comparison of all Options:

| | Description | Cost (±50%) | Reliability Improvements | Estimated SAIFI* | Estimated SAIDI* |
|---|---|---|---|---|---|
| - | Status Quo - Do nothing | $0 | Worst | 7.0 | 38.1hr |
| 1 | Build new 44kV line from Brockville | $11,250,000 | Good | 7.0 | 6.3hr |
| 2 | Extend second 44kV line from Frontenac TS (Kingston) | $6,500,000 | Fair | 7.0 | 24.7hr |
| 3 | Install new tie switches between two HONI 44kV Lines | $106,000 | Fair | 7.0 | 29.4hr |
| 4 | Rebuild 7.5km Joint-Use (shared) line – John F Scott Rd | $702,000 | Fair | 5.0 | 19.4hr |
| ➔ | Do options 3 and 4 | $808,000 | Better | 5.0 | 18.1hr |

**RECOMMEND:**

- **Do Options 3 and 4.**
- **CNPI (including Niagara rate base) existing budget can accommodate these projects without additional application to OEB.**

# What will happen if the Town requires Option 1 or 2

- CNPI will make a special application to OEB
- OEB will very unlikely to allow CNPI customers as a group to pay the cost through rates
- Town of Gananoque will have to pay the cost.