GODERICH HYDRO West Coast Huron Energy Inc.

ERIE THAMES POWERLINES

March 14, 2018

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

RE: Application under section 86 of the *OEB Act, 1998* to amalgamate WCHEI and ETPL
Board File No: EB-2018-0082

Dear Ms. Walli,

Please find enclosed two copies of an application of Erie Thames Powerlines Corporation ("ETPL") and West Coast Huron Energy Inc. ("WCHEI") seeking leave to amalgamate WHCHI into ETPL under section 86 of the *Ontario Energy Board Act, 1998* (Ontario) and related relief.

As the Board is aware, we submitted an original application on January 23 and subsequent amendments on February 8 which were intended to request the consolidation of ETPL and WCHEI via an amalgamation of WCHEI into ETPL. After receiving feedback from Board staff, we wish to submit a complete new application to clarify the relief being requested. In particular, we have removed all references to "LDC Co" to avoid confusion that a new legal entity was required in respect of this application. As reflected in the attached application, the parties are requesting that the Board approve the amalgamation of WCHEI into ETPL and the subsequent amendment of ETPL's distribution license to include WCHEI's service territory.

The complete application will be submitted electronically today via the Board's web portal. Two hard copies of this submission are being sent to the Board via courier.

If you have any questions, please do not hesitate to contact us.

Sincerely,

[redacted]


Graig Pettit
Director, Regulatory – Finance & Customer Relations
Erie Thames Powerlines Corporation
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President
West Coast Huron Energy Inc.
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cc: Chris White, President – Erie Thames Powerlines Corporation
Tyler Moore, Legal Counsel to the Parties




Your Home Town Utility

# MAAD Application

## EB-2018-0082

## Revision Filed: March 14, 2018

**EB-2018-0082**

**REVISED**

**IN THE MATTER OF** Sections 86 and 18 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Sched. B, as amended; and

**AND IN THE MATTER OF** an application for the relief necessary to effect the amalgamation of West Coast Huron Energy Inc. into Erie Thames Powerlines Corporation in the manner set out in this Application.

**APPLICATION FILED:**

**March 14, 2018**


**Erie Thames Powerlines Corporation**
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## ATTACHMENTS

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# MAPPING OF APPLICATION TO HANDBOOK FILING REQUIREMENTS

**Handbook refers to the Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016.*

| | Filing Requirements | Reference |
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| **2.1 Index** | Index | Exhibit A, Tab 1, Schedule 1 |
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| **2.2.1 Administrative** | | |
| | Certification of the Evidence | Exhibit B, Tab 1, Schedule 1 |
| | Details of the authorized representative of the applicant/s, including the name, phone and fax numbers, and email and delivery addresses | Exhibit B, Tab 3, Schedule 1, Attachment 1 |
| | Legal name of the other party or parties to the transaction, if not an applicant | Exhibit B, Tab 3, Schedule 1, Attachment 1 |
| | Details of the authorized representative of the other party or parties to the transaction, including the name, phone and fax numbers, and email and delivery addresses | Exhibit B, Tab 3, Schedule 1, Attachment 1 |
| | Brief description of the nature of the transaction for which approval of the OEB is sought by the applicant or applicants | Exhibit B, Tab 2, Schedule 1 |
| **2.2.2 Description of the Business of the Parties to the Transaction** | | |
| | Describe the business of each of the parties to the proposed transaction, including each of their electricity sector affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity. | Exhibit B, Tab 3, Schedule 2; |
| | Describe the geographic territory served by each of the parties to the proposed transaction, including each of their affiliates, if applicable, noting whether service area boundaries are contiguous or if not the relative distance between service boundaries. | Exhibit B, Tab 3, Schedule 3, Attachments 2-3 |
| | Describe the customers, including the number of customers in each class, served by each of the parties to the proposed transaction. | Exhibit B, Tab 3, Schedule 4 |
| | Describe the proposed geographic service area of each of the parties after completion of the proposed transaction. | Exhibit B, Tab 3, Schedule 5, Attachments 4 |
| | Provide a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates. | Exhibit B, Tab 3, Schedule 2 |

| | Filing Requirements | Reference |
|---|---|---|
| | If the proposed transaction involves the consolidation of two or more distributors, please indicate the current net metering thresholds of the utilities involved in the proposed transaction. The OEB will, in the absence of exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Applicants must indicate if there are any special circumstances that may warrant the OEB using a different methodology to determine the net metering threshold for the new or remaining utility. | Exhibit B, Tab 3, Schedule 6 |
| **2.2.3 Description of the Proposed Transaction** | | |
| | Provide a detailed description of the proposed transaction. | Exhibit B, Tab 4, Schedule 1 |
| | Provide a clear statement on the leave being sought by the applicant, referencing the particular section or sections of the Ontario Energy Board Act, 1998. | Exhibit B, Tab 2, Schedule 1 |
| | Provide details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction. | Exhibit B, Tab 4, Schedule 2 |
| | Provide all final legal documents to be used to implement the proposed transaction. | Exhibit B, Tab 4, Schedule 3 |
| | Provide a copy of appropriate resolutions by parties such as parent companies, municipal council/s, or any other entities that are required to approve a proposed transaction confirming that all these parties have approved the proposed transaction. | Exhibit B, Tab 4, Schedule 4, Attachment 6 |
| **2.2.4 Impact of the Proposed Transaction** | | |
| *Objective 1 - Protect consumers with respect to prices and the adequacy, reliability and quality of electricity service* | | |
| | Indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service. | Exhibit B, Tab 5, Schedule 1 |
| | Provide a year over year comparative cost structure analysis for the proposed transaction, comparing the costs of the utilities post transaction and in the absence of the transaction. | Exhibit B, Tab 5, Schedule 2 |
| | Provide a comparison of the OM&A cost per customer per year between the consolidating distributors. | Exhibit B, Tab 5, Schedule 3 |
| | Confirm whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction. | Exhibit B, Tab 5, Schedule 4 |
| | Describe how the distribution or transmission systems within the service areas will be operated. | Exhibit B, Tab 5, Schedule 5 |

| | | |
|---|---|---|
| | **Filing Requirements** | **Reference** |
| *Objective 2 - Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry* | | |
| | Indicate the impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity), identifying the various aspects of utility operations where the applicant expects sustained operational efficiencies (both quantitative and qualitative). | Exhibit B, Tab 6, Schedule 1 |
| | Identify all incremental costs that the parties to the proposed transaction expect to incur which may include incremental transaction costs (e.g. legal, regulatory), incremental merged costs (e.g. employee severances), and incremental on-going costs (e.g. purchase and maintenance of new IT systems). Explain how the consolidated entity intends to finance these costs. | Exhibit B, Tab 6, Schedule 2 |
| | Provide a valuation of any assets or shares that will be transferred in the proposed transaction. Describe how this value was determined. | Exhibit B, Tab 6, Schedule 3 |
| | If the price paid as part of the proposed transaction is more than the book value of the assets of the selling utility, provide details as to why this price will not have an adverse effect on the financial viability of the acquiring utility. | *Not Applicable* |
| | Provide details of the financing of the proposed transaction. | Exhibit B, Tab 6, Schedule 4 |
| | Provide financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years. | Exhibit B, Tab 6, Schedule 5, Attachments 7-10 |
| | Provide pro forma financial statements for each of the parties (or if an amalgamation, the consolidated entity) for the first full year following the completion of the proposed transaction. | Exhibit B, Tab 6, Schedule 6, Attachment 11 |
| **2.2.5 Description of the Proposed Transaction** | | |
| | Indicate a specific deferred rate rebasing period that has been chosen. | Exhibit B, Tab 7, Schedule 1 |
| | For deferred rebasing periods greater than five years, confirm that the ESM will be as required by the 2015 Report and the Handbook | Exhibit B, Tab 7, Schedule 2 |
| | If the applicant’s proposed ESM is different from the ESM set out in the 2015 Report, the applicant must provide evidence to demonstrate the benefit to the customers of the acquired distributor | *Not Applicable* |

| | Filing Requirements | Reference |
|---|---|---|
| **2.2.6 Other Related Matters** | | |
| | a) Implementation of new or the extension of existing rate orders | Exhibit B, Tab 8, Schedule 1 |
| | b) Transfer of rate order and licence | Exhibit B, Tab 8, Schedule 1 |
| | c) Licence amendment and cancellation | Exhibit B, Tab 8, Schedule 1 |
| | d) Approval to continue to track costs to the deferral and variance accounts currently approved by the OEB | Exhibit B, Tab 8, Schedule 1 |
| | e) Approval to use different accounting standards for financial reporting following the closing of the proposed transaction | Exhibit B, Tab 8, Schedule 1 |

## CERTIFICATION OF EVIDENCE

The undersigned, the President and CEO of Erie Thames Powerlines Corporation, in my capacity as an officer of that corporation and without personal liability, hereby certify, to the best of my knowledge, as at the date of certification, that the evidence in this Application is accurate, consistent and complete.

[redacted]

Chris White, President & CEO

## CERTIFICATION OF EVIDENCE

The undersigned, the President and CEO of West Coast Huron Energy Inc., in my capacity as an officer of that corporation and without personal liability, hereby certify, to the best of my knowledge, as at the date of certification, that the evidence in this Application is accurate, consistent and complete.

[redacted]

Larry McCabe, President

# APPLICATION

## 1.0 INTRODUCTION

This is an application ("Application") to the Ontario Energy Board ("OEB" or the "Board") for the relief necessary to effect the amalgamation of West Coast Huron Energy Inc. ("WCHEI") into Erie Thames Powerlines Corporation ("ETPL") to create a single local distribution company. It is the Parties' intention that WCHEI will be merged into ETPL in that (i) the articles of amalgamation for LDC Co will in substance contain the provisions of the articles of incorporation of ETPL and (ii) WCHEI's distribution license will be transferred to ETPL and subsequently merged with ETPL's distribution license no later than one hundred and twenty (120) days following approval of this Application.

This Application is the culmination of a long-standing relationship and shared service arrangements between the Applicants. In particular, ETPL and its holding company, ERTH Corporation ("ERTH") and its competitive affiliates have provided a variety of services to WCHEI since 2002.

The specific items of relief are discussed in Section 3.0 of this schedule below.

The Application follows the Filing Requirements contained in the Board's January 19, 2016 Handbook to Electricity Distributor and Transmitter Consolidations (the "Handbook"). The mapping of the Application's contents to the Handbook's Filing Requirements is provided in Exhibit A, Tab 1, Schedule 2.

The Application adheres to the Board's March 26, 2015 *Report on Rate-Making Associated with Distributor Consolidation* (the "Consolidation Policy") and to the Board's Handbook.

For the purposes of this Application, WCHEI and ETPL will be collectively referred to as the "Applicants" and the "Parties".

### The "No Harm" Test

The Applicants had prime consideration for the "no harm" test used by the OEB in adjudicating Mergers, Acquisitions, Amalgamations and Divestitures ("MAADs") applications made under Section 86 of the OEB Act to ensure that the proposed transaction would not have an adverse effect relative to the *status quo* of each of the Parties and their customers in keeping with the OEB's statutory objectives. In fact, as demonstrated by this Application, it is the intention of the Applicants that the proposed amalgamation of WCHEI and ETPL provide a material benefit to their customers. The Applicants submit that the proposed amalgamation will not have an adverse effect in terms of the factors identified in the Board's objectives in section 1 of the OEB Act. Rather, as can be seen in Exhibit B, Tab 5, Schedule 2 (in which the Applicants have provided a comparison of the cost structure among the Parties, *status quo* versus post consolidation), it is anticipated that customers will benefit from the proposed transaction. Accordingly, the Applicants submit that the proposed consolidation meets the OEB's "no harm" test.

In particular, as will be seen from the evidence in the Application:

- The proposed transaction will positively impact the customers of the Parties with respect to price and the adequacy, reliability, and quality of electricity service. Over the course of the nine year rebasing deferral period, customers will benefit from distribution rates that are lower than they would have been had the *status quo* of two independent LDCs been maintained;

- ETPL will continue to promote electricity conservation and demand management;

- ETPL will continue to facilitate the implementation of a smart grid in Ontario;

- ETPL will continue to promote the use and generation of electricity from renewable sources and will continue to reinforce the distribution systems throughout its service territories in order to accommodate the connection of renewable energy generation facilities;

- Once the consolidation is completed and the businesses are integrated, ETPL expects to be compliant with all OEB Codes, Distribution Licences, IESO Market Rules and statutes and regulations;

- The Parties have willingly come together to consolidate ETPL and WCHEI. The transactions demonstrate the benefits contemplated by voluntary consolidation within the electricity sector in Ontario. Although these transactions will result in some transaction and transition costs, the Applicants anticipate realizing real cost synergies and operational efficiencies, as well as benefits from economies of scale;

- The Board has acknowledged that "consolidation also enables distributors to address challenges in an evolving electricity industry." The proposed consolidation will also promote the objectives of the OEB's *Renewed Regulatory Framework for Electricity Distributors – A Performance Based Approach*.

- ETPL, ERTH and its competitive affiliates have been assisting WCHEI for over 15 years by providing a variety of services and support (including Billing, Hosting, Engineering, Management, and Consulting services). The proposed consolidation of WCHEI and ETPL is therefore a natural progression of the Parties close relationship, and WCHEI's customers will benefit from the new care and control relationship with ERTH and the additional resources able to service WCHEI's distribution system.

It is therefore the Applicants' respectful submission that the amalgamation proposed in this Application clearly meets the Board's "no harm" test.

**LDC Profiles**

WCHEI is an electricity distribution company, regulated by the OEB. It provides electricity to approximately 3,745 residential, commercial and industrial customers in the Town of Goderich. WCHEI is wholly-owned by the Town of Goderich. WCHEI has no affiliates. A more detailed description of WCHEI's service territory and customer base is set out Exhibit B, Tab 3, Schedules 2-4.

ETPL is an electricity distribution company, regulated by the OEB. It provides electricity to approximately 19,156 residential, commercial and industrial customers in the communities of Port Stanley, Aylmer, Belmont, Ingersoll, Thamesford, Otterville, Norwich, Burgessville, Beachville, Embro, Tavistock, Mitchell, Dublin and Clinton.

ETPL is wholly-owned by ERTH, a municipal holding company which is wholly-owned by eight municipalities, including: Town of Ingersoll, Township of East Zorra – Tavistock, Township of Zorra, Municipality of Central Elgin, Township of South-West Oxford, Town of Aylmer, Municipality of West Perth, and Township of Norwich. ERTH's businesses and corporate structure, including ETPL's service territory, customers and non-regulated affiliates are described in greater detail in Exhibit B, Tab 3, Schedules 2-4.

## 2.0 OVERVIEW OF THE APPLICATION

Subject to approval, the consolidation proposed in this Application will be implemented by way of two transactions that will occur sequentially but one right after the other and will culminate in a single distributor carrying on business as a single corporation. In particular, the consolidation will involve a two-part transaction:

1. ERTH and the Town of Goderich have executed a share purchase agreement pursuant to which ERTH will acquire all of the shares of WCHEI. In return, the Town of Goderich will receive shares in ERTH; and

2. Immediately upon the closing of the transaction above, WCHEI and ETPL will be amalgamated via a short-form amalgamation under section 177(2) of the *Business Corporations Act* (Ontario). The articles of amalgamation for the merged entity will in substance contain the provisions of the articles of incorporation of ETPL.

The legal agreements implementing the proposed transaction (described in Exhibit B, Tab 4, Schedule 3) contemplates the transaction closing to occur within 30 days following the date on which OEB approval is obtained and other closing conditions have been satisfied or waived.

The consolidation proposed in this Application also involves:

1. the transfer of WCHEI's Electricity Distribution Licence to ETPL upon approval of this Application, and

2. no later than 120 days following such approval, the amendment of ETPL's Electricity Distribution Licence to include the WCHEI service area (and the cancellation of the license of WCHEI.)

3. Rates within the historical ETPL area will continue until a decision in EB-2018-0082. ETPL will continue the current rates for the customers of WCHEI.

**Other Matters**

ETPL's rebasing will be deferred for a period of nine years following the completion of the consolidation. The Applicants intend for ETPL to integrate the distribution systems of the predecessor distributors following the completion of the consolidation, and during the rebasing deferral period.

## 3.0 OEB APPROVALS SOUGHT

The relief requested by the Applicants is the following:

1. **Proposed Transactions**:

   (a) leave for WCHEI and ETPL to amalgamate and continue as a corporation, pursuant to Section 86(1)(c) of the OEB Act;

   (b) leave for WCHEI to transfer its distribution systems to ETPL pursuant to Section 86(1)(a) of the OEB Act;

(c) leave for WCHEI to transfer its distribution licenses and rate orders to ETPL, pursuant to Section 18 of the OEB Act; and

(d) the amendment of the distribution licence for ETPL under Section 18 of the OEB Act to include the service area of WCHEI no later than 120 days after the approval of this Application (to be followed immediately by the cancellation of the distribution licence of WCHEI.)

(e) Such necessary rate orders to transfer the existing WCHEI rate orders to ETPL.

The Applicants intend to maintain all distribution activities, including applicable licences and rate orders in ETPL.

2. **Deferred Rebasing**:

(a) The Applicants confirm that they have chosen to defer ETPL's rebasing for nine years from the date of closing the last of the proposed transactions, consistent with the Board's March 26, 2015 Report on Rate- Making Associated with Distributor Consolidation (the "Consolidation Policy") and with the Handbook.

(b) The Applicants have relied upon the guidance in the Consolidation Policy and in the Handbook in the structuring of the transaction. The Handbook states that "Consolidating entities that propose to defer rebasing beyond five years, must implement an [Earnings Sharing Mechanism ("ESM")] for the period beyond five years." (Handbook, p.16)

(c) The ESM proposed by the Applicants for years six to nine of the rebasing deferral period in this Application is consistent with the Consolidation Policy which states that the ESM:

"*would be implemented if the consolidated entity's ROE was greater than 300 bps above the allowed ROE as set out under the incentive regulation policy. The ESM will be based on a 50:50 sharing of excess earnings with consumers.*" (Consolidation Policy, p. 12)

(d) The regulatory net income will be calculated, for the purpose of earnings sharing, in the same manner as net income for regulatory purposes under the Board's Reporting and Record Keeping Requirements ("RRRs"). The Applicants expect that the computation of the ROE will exclude revenue and expenses that are not otherwise included for regulatory purposes.

Pursuant to the Handbook, issues related to rate making for ETPL's service areas, including the treatment of any ESM, Capital Variance and/or Efficiency Adjustments, are matters for future rate applications and are not in scope for this Application, subject to the comments below regarding the treatment of existing rate orders and rate riders.

3. **Post-Closing Distribution Rate Issues**:

As identified above, the Applicants are requesting that the rate orders of WCHEI be transferred to ETPL following the completion of the consolidation. Both of WCHEI and ETPL have a rate order that contains a number of rate riders established in order to dispose of balances in specified deferral and variance accounts. Certain riders will expire on dates determined in the Order(s) of the Board by which the riders were established. Others will be in place until the applicable distributor's next rebasing;

The Applicants provide in Attachment 12 their OEB approved and proposed rate orders.

The Applicants are requesting approval to continue to track costs to the regulatory asset accounts currently approved by the Board for each of ETPL and WCHEI and to seek disposition of their balances at a future date.

For the Board's information, each of ETPL and WCHEI has transitioned to IFRS for financial accounting purposes, and ETPL, following amalgamation, will also be using IFRS.

## 4.0 FORM OF HEARING

Under the Board's *Rules of Practice and Procedure*, the Board may hold an oral, electronic or written hearing. ETPL applied to the Board with respect to the similar transactions effecting the consolidation of ETPL with West Perth Power Inc. and Clinton Power Corporation (EB-2009-0156, EB-2009-0157 and EB-2010-0386). In each case, these applications were approved by the OEB via a written hearing. The Applicants hereby request that this Application also be heard by way of a written hearing.

## ADMINISTRATIVE - IDENTIFICATION OF THE PARTIES

Please see Attachment 1 which sets out the following information, as provided in Section 2.2.1 of the OEB's Filing Requirements for Consolidation Applications:

## DESCRIPTION OF THE BUSINESS OF THE PARTIES TO THE TRANSACTION

This schedule provides a detailed description of each of the Parties to the transaction including a discussion of the electricity distribution operations and the activities of their affiliates.

### West Coast Huron Energy Inc.

West Coast Huron Energy Inc. ("WCHEI") owns and is responsible for the operation, maintenance and management of the assets associated with the distribution of electrical power in the Town of Goderich. Its service territory is specified in Distribution Licence ED-2001-0510, a copy of which is available on the Board's website. West Coast Huron Energy Inc. serves approximately 3,745 customers.

### Erie Thames Powerlines Corporation

Erie Thames Powerlines Corporation ("ETPL") owns and is responsible for the operation, maintenance and management of the assets associated with the distribution of electrical power in the communities of Aylmer, Port Stanley, Belmont, Ingersoll, Thamesford, Otterville, Norwich, Burgessville, Beachville, Embro, Tavistock, Clinton, Mitchell, and Dublin. Its service territory is specified in Distribution Licence ED-2002-0516, a copy of which is available on the Board's website. Erie Thames Power Corp. serves approximately 19,156 customers.

### ERTH Corporation

ETPL is a wholly-owned subsidiary of ERTH Corporation ("ERTH), a holding company owned by eight Ontario municipalities. ERTH is responsible for the oversight of ETPL and competitive subsidiaries. The Applicant also provides shared corporate services to ETPL and its electricity sector affiliates, which include the following:

#### ERTH Inc.

ERTH Inc. is a wholly-owned non-regulated holding company that does not conduct business but is the sole owner of ERTH's operating competitive businesses, including ERTH (Holdings) Inc. and ERTH Business Technologies Inc.

#### ERTH (Holdings) Inc.

ERTH (Holdings) Inc. ("EHI") provides the following competitive services to the utility and municipal sectors within Ontario:

- Utility and power line construction and maintenance for utilities, generators, municipalities, developers and other electricity customers

- Traffic and street lighting services for municipalities and developers

- High voltage and low voltage services, including substation inspection, maintenance and repair, for utilities, generators and large customers.

- Meter Service Provider (MSP) services for wholesale market participants, including utilities, generators and large end user;

- Testing, verification and sealing of electricity meters for utilities and sub-metering providers;

- Electricity, water and sewer billing for utilities and municipalities, including billing software implementation and hosting services, bill print and stuffing services, and customer information system support.

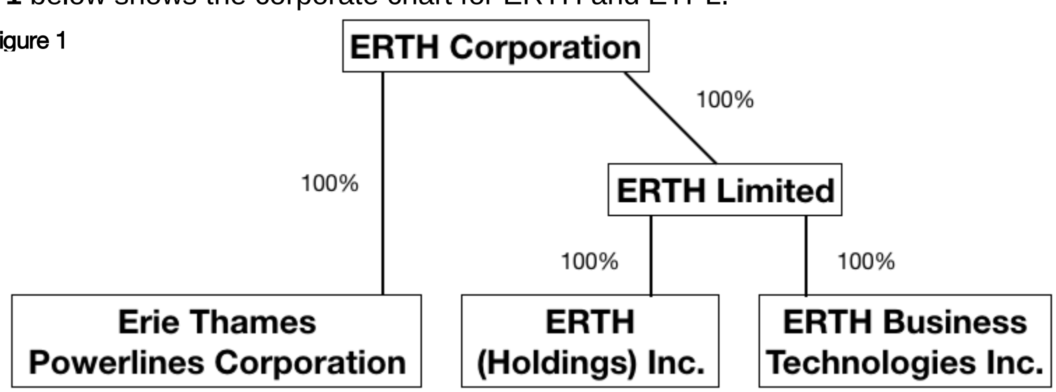
EHI has also internally developed and commercialized an estimating and job management software tool, Quadra, which has utility and other customers in Ontario California, Illinois, North Dakota, Washington, Colorado, Michigan, New Hampshire, New York, Pennsylvania, Maryland, Ohio, Kentucky, North Carolina, Louisiana, British Virgin Islands, and Australia.

**ERTH Business Technologies Inc.**

ERTH Business Technologies Inc. ("EBT") provides the hub and spoke and electronic business transaction services to electricity utilities and retailers in Ontario. EBT also provides retail billing services to gas and electricity customers in Ontario and various U.S. states, including New York, New jersey, Ohio, Pennsylvania, Maryland, Massachusetts, and Illinois.

**Figure 1** below shows the corporate chart for ERTH and ETPL.

Figure 1



## GEOGRAPHIC TERRITORY SERVED BY THE PARTIES TO THE TRANSACTION

The geographic territory for each of the Parties is described in detail in the distribution licences referenced in Exhibit B, Tab 3, Schedule 2.

A map of WCHEI's service area is provided as Attachment 2. WCHEI's service area is generally contiguous within the Town of Goderich and serviced by its operations centre located at 240 Huckins Street in the town of Goderich.

A map of ETPL's service area is provided as Attachment 3. The 14 communities within ETPL's service territory are non-contiguous. The boundaries for each of ETPL's 14 communities served are generally coincident to the town boundaries themselves. ETPL's service territory is currently served by 3 regional service centres.

- North – 3276 Perth County Rd 180, Staffa, west of Mitchell;
- Central - 143 Bell Street, Ingersoll; and
- South - 280 Elm Street, Aylmer.

Despite the non-contiguous nature of ETPL's service territory, these communities have always been effectively served by ETPL.

## DESCRIPTION OF THE CUSTOMERS

***Figure 2*** provides the number of customers by customer class for each of the Parties:

| Customer Class | Number of Customers/Connections | | |
|---|---|---|---|
| | ETPL | WCHE | Total |
| Residential | 16,987 | 3,234 | 20,221 |
| GS<50 | 2,006 | 461 | 2,467 |
| GS>50 | 162 | 49 | 211 |
| Large Use | 1 | 1 | 2 |
| Unmetered Scattered Load | 128 | 4 | 132 |
| Sentinel Lighting | 243 | 8 | 251 |
| Street Lighting | 5,998 | 1,298 | 7,296 |
| Embedded Distributor | 4 | - | 4 |
| **Total** | **25,529** | **5,055** | **30,584** |

## GEOGRAPHIC SERVICE AREA - POST TRANSACTION

Attachment 4 shows a map of the proposed service area for ETPL following consolidation. In addition, Attachment 4 shows the distances and drive times to each community served by the proposed service centres in the North, Central and South regions between the non-contiguous service boundaries served by ETPL following the amalgamation with WCHEI..

Consistent with the nature of ETPL's existing service territory, the new amalgamated service territory will also be non-contiguous. WCHEI's service area is approximately 20 kilometres from the northernmost point of ETPL's service territory (Clinton). While there is some geographic advantage as a result of contiguity, the Applicants expect to leverage operational efficiencies across the entire service area by utilizing the following three service centres to service the area of ETPL post-amalgamation as divided into three regions:

- North - 240 Huckins Street, Goderich;
- Central - 143 Bell Street, Ingersoll; and
- South - 280 Elm Street, Aylmer.

## NET METERING THRESHOLDS

The current net metering thresholds ("NMT") of WCHEI and ETPL are set out in Figure 3 below. Also set out below is the summation of the NMT for ETPL following the amalgamation. There are no special circumstances to the Applicants' knowledge that would warrant the OEB using a different methodology to determine the net metering threshold for each utility.

It is noted that the Ontario's new net metering regulation, Ontario Regulation 541/05 – Net Metering came into force effective July 1, 2017. The Applicants recognize that the applicability of the noted total net metering threshold may be impacted by this new regulation.

***Figure 3***

| LDC | kW Threshold |
|---|---:|
| ETPL | 827 |
| WCHEI | 267 |
| Total | 1094 |

## DESCRIPTION OF THE TRANSACTION

The Applicants are proposing a series of transactions that will result in the amalgamation of WCHEI and ETPL and the consolidation of their respective businesses into a single distributor.

Subject to Board approval, the consolidation proposed in this Application will be implemented by way of a two transactions that will culminate in a single distributor carrying on business as a single corporation. In particular, the consolidation will involve a two-part transaction:

1. ERTH and the Town of Goderich have executed a share purchase agreement (Attachment 5) pursuant to which ERTH will acquire all of the shares of WCHEI. In return, the Town of Goderich will receive shares in ERTH; and

Immediately upon the closing of the transaction above, WCHEI and ETPL will be amalgamated via a short-form amalgamation under section 177(2) of the *Business Corporations Act* (Ontario). The articles of amalgamation for the amalgamated entity will in substance contain the provisions of the articles of incorporation of ETPL.

The legal agreements implementing the proposed transaction (described in Exhibit B, Tab 4, Schedule 3) contemplates the transaction closing to occur within 30 days following the date on which OEB approval is obtained and other closing conditions have been satisfied or waived.

The consolidation proposed in this Application also involves (i) the transfer of WCHEI's Electricity Distribution Licence to ETPL upon approval of this Application, and (ii) no later than 120 days following such approval, the amendment of ETPL's Electricity Distribution Licence to include the WCHEI service area (and the cancellation of the license of WCHEI.)

## DETAILS OF CONSIDERATION

As consideration for the shares of WCHEI, the Town of Goderich will receive one equal voting share and 6,095,924 non-voting common shares in the Applicant (representing a relative economic ownership position in the Applicant of 22.5%).

Upon completion of the proposed transaction, the share ownership percentage of ERTH will be as follows (notwithstanding and required adjustments);

- Town of Ingersoll 30.2%
- Town of Goderich 22.5%
- Town of Aylmer 15.0%
- Municipality of West Perth 6.2%
- Municipality of Central Elgin 7.2%
- Township of Norwich 6.8%
- Township of East Zorra Tavistock 5.0%
- Township of Southwest Oxford 1.7%
- Township of Zorra 5.4%

ERTH will in turn own 100% of LDC Co.

## LEGAL AGREEMENTS TO IMPLEMENT THE TRANSACTION

The terms and conditions under which the Applicants will achieve the amalgamation of WCHEI and ETPL are set out in the following agreements:

- A *Share Purchase Agreement* (“SPA”) sets out the terms and conditions under which the shares of WCHEI will be acquired by ERTH. The SPA is provided as Attachment 5. The SPA has been redacted to remove any “personal information” within the meaning of the *Freedom of Information and Protection of Privacy Act* (Ontario) (“FIPPA”) and pursuant to Section 42 of that Act such information should not be released publicly.

## RESOLUTIONS APPROVING THE TRANSACTION

Copies of the Resolutions of the Town of Goderich and the eight municipal shareholders of ERTH approving the proposed transaction are provided in Attachment 6.

## OVERALL IMPACT OF THE TRANSACTION

The Applicant submits that the proposed transaction will result in ratepayers experiencing beneficial impacts with respect to prices and the adequacy, reliability and quality of electricity service. ETPL, ERTH and its electricity sector affiliates already provide a extensive amount of services to WCHEI and accordingly, it is expected that the transition of ownership will be relatively seamless from the perspective of the customer and constitute an enhancement of services currently provided. Furthermore, the proposed transaction will result in savings and operational efficiencies due to a reduction in administrative burdens associated with moving to one legal entity under a single license. For example, the amalgamation into one legal entity under a single license will result in reduced administrative, governance, audit and regulatory costs and related resources required.

The impact of the proposed transaction on consumers with respect to the price, adequacy, reliability and quality of distribution service is addressed in more detail below.

### Price

The proposed consolidation is expected to deliver material electricity ratepayer savings relative to the *status quo,* i.e., in the absence of a consolidation. Ratepayers of ETPL after the merger are expected to enjoy lower rates through the nine year rebasing deferral period in comparison to the *status quo* for the reasons discussed below. Ratepayers are also expected to experience greater savings in comparison to the *status quo* from the time of the first anticipated rebasing, Nine years following the completion of the consolidation, due to cost savings resulting from synergies. These benefits, cost savings and synergies are detailed in Exhibit B, Tab 6, Schedule 1.

*Rebasing Deferral Period – Nine Years from the Completion of the Consolidation*:

Each of the consolidating distributors would have filed Cost of Service or Custom IR applications during the proposed nine year rebasing deferral period in the absence of the proposed consolidation. The pre-existing rate plans for WCHEI filed IRM application EB-2017-0083 effective May 1$^{st}$ 2018 and ETPL's filed Cost of Service rate application EB-2017-0038 effective May 1$^{st}$, 2018 will continue until their expiry, and rate adjustments will then take place under Price Cap Incentive Rate Mechanism (the "Price Cap IR") through to the first rebasing of ETPL following the amalgamation In the absence of the proposed consolidation and rebasing deferral, rebasing for WCHEI and ETPL would have taken place in 2019 and 2023 respectively, and projected rate increases would have been greater than under Price Cap IR. Accordingly, the proposed transaction results in lower ETPL rates than the *status quo* during the rebasing deferral period from the time each Party's rate plan expires.

*Customer Value Creation*

Following the approved merger, ETPL will be focused on reducing operating expenditures. It will improve productivity through better utilization of existing assets. ETPL will leverage best practices in asset management from the Parties. This includes the evaluation of long term capital plans, maintenance practices, design standards, and operating standards for alignment of best practices.

The net cost savings discussed above would not be possible without the proposed consolidation. ETPL will provide distribution rates to customers that will be lower than they otherwise would have been, had the Parties remained standalone entities.

The Applicants expect that the consolidated customer base will create opportunities for ETPL and its electricity sector affiliates to provide additional services while adhering to applicable OEB Codes and related regulations. Currently, an electricity sector affiliate of ETPL provides water billing services to most of its municipal shareholders on the electricity bills. This approach will be extended to water customers in the Town of Goderich. Further opportunities may also present themselves, including in the area of CDM.

**Adequacy, reliability and quality of service**

The Applicants are committed to maintaining the quality, reliability, and adequacy of electricity service for its customers. ETPL has committed to maintain the existing operations centre in the Town of Goderich and, as a result, it expected response times will not change for WCHEI customers. ETPL intends to move ETPL's operations centre in Mitchell to Goderich to avoid duplication. However, the expected response times for customers in Mitchell will not change. Accordingly, ETPL will have a total of three service centres across their service areas. These service centres will continue to be used for de-centralized functions such as construction and maintenance, trouble response, logistics, fleet services, and metering. Accordingly, the adequacy, reliability, and quality of electricity service will be maintained. ETPL will maintain or improve service levels of its predecessor utilities (for example, through implementation of new technologies and adoption of best work practices).

The Applicants' intention is that ETPL will harmonize the engineering standards of its predecessor utilities following the merge, which will enable more efficient and effective inventory management and ensure sufficient spare equipment for higher reliability. ETPL will implement a comprehensive review and recommend best engineering standards and practices to be followed. The review will give due consideration to service reliability, costs, and risks.

Customers in all affected service areas will benefit from being served by a larger utility that will have an expanded ability to monitor, report on and improve system reliability and power quality, given its greater resources.

The Parties' policies and practices for expansion of the distribution system will be standardized across the new geographic service territory. This is expected to facilitate economic growth in the service territory as developers will receive standard Offers to Connect and will be able to deal with only one distributor across these regions.

As identified above, ETPL expects to maintain the three existing service centres after the merge located in: Ingersoll, Aylmer and Goderich. The Operations staff that currently responds to outages and power quality issues will continue to serve the communities that they serve at present. The Applicants anticipate that response times will not degrade given that these staffing levels will not be changing. In fact, during large scale outages, ETPL will have the ability to draw upon a larger number of operations staff for storm restoration efforts.

The System Average Interruption Duration Index ("SAIDI"), the average outage duration for each customer served, is commonly used as a reliability indicator by electricity utilities. The System Average Interruption Frequency Index ("SAIFI"), the average number of interruptions a customer would experience, is also a key reliability indicator. ETPL is expected to maintain and improve upon the five-year average reliability indices and the OEB Customer Service Standard metrics for its customers. Each operating area of ETPL post-amalgamation has unique distribution system characteristics; capital and maintenance plans are based on sound asset management strategies that address the specific needs in each of the service areas, including addressing reliability issues.

The five year historical reliability metrics for WHCEI and ETPL are provided in Figure 4 below.

**Figure 4**

| Description | 2012 | 2013 | 2014 | 2015 | 2016 | Average |
|---|---|---|---|---|---|---|
| **SAIDI** | | | | | | |
| ETPL | 1.47 | 0.41 | 0.59 | 0.73 | 1.46 | 0.932 |
| WCHE | 0.42 | 3.56 | 0.24 | 0.19 | 0.15 | 0.912 |
| Combined | 0.95 | 1.99 | 0.42 | 0.46 | 0.81 | 0.922 |
| **SAIFI** | | | | | | |
| ETPL | 0.31 | 0.2 | 0.3 | 0.48 | 0.24 | 0.306 |
| WCHE | 0.19 | 1.16 | 0.19 | 0.43 | 0.06 | 0.406 |
| Combined | 0.25 | 0.68 | 0.25 | 0.46 | 0.15 | 0.356 |

Following the merger, ETPL will maintain and improve service levels of its predecessor utilities through measures such as the implementation of new technologies and adoption of best work practices. ETPL will also be able to reduce duplicate CDM program administration costs. Best practice processes and systems (e.g., customer management functions, call centre service, and billing) of the two predecessor utilities will be adopted across ETPL in order to improve productivity and raise the quality of service for all customers.

The proposed consolidation will create an entity jointly-owned by nine municipalities that will keep this critical public service entirely within public control.

## YEAR OVER YEAR COMPARATIVE COST STRUCTURE ANALYSIS

Figure 5 below provides a comparison of the OM&A cost structure among the Parties, *status quo* versus post consolidation.

**Figure 5**

| Distributor OM&A | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| ETPL | $ 6,181,909 | $ 6,468,593 | $ 6,597,965 | $ 6,729,924 | $ 6,864,523 |
| WCHE | $ 1,870,617 | $ 1,908,029 | $ 1,946,190 | $ 1,985,113 | $ 2,024,816 |
| **Total OM&A Status Quo** | **$ 8,052,526** | **$ 8,376,622** | **$ 8,544,155** | **$ 8,715,038** | **$ 8,889,338** |
| OM&A Cost Savings | $ - | -$ 344,500 | -$ 394,500 | -$ 498,500 | -$ 593,500 |
| Transition Costs | | $ 233,089 | $ 101,976 | | |
| **New ETPL OM&A** | **$ 8,052,526** | **$ 8,265,211** | **$ 8,251,631** | **$ 8,216,538** | **$ 8,295,838** |
| Savings for Customer | $ - | $ 111,411 | $ 292,524 | $ 498,500 | $ 593,500 |
| **Cumulative Savings** | | **$ 111,411** | **$ 403,935** | **$ 902,435** | **$ 1,495,935** |

| Distributor OM&A | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|
| ETPL | $ 7,001,813 | $ 7,141,849 | $ 7,284,686 | $ 7,430,380 | $ 7,578,988 |
| WCHE | $ 2,065,312 | $ 2,106,618 | $ 2,148,751 | $ 2,191,726 | $ 2,235,560 |
| **Total OM&A Status Quo** | **$ 9,067,125** | **$ 9,248,468** | **$ 9,433,437** | **$ 9,622,106** | **$ 9,814,548** |
| OM&A Cost Savings | -$ 668,500 | -$ 681,870 | -$ 695,507 | -$ 709,418 | -$ 723,606 |
| Transition Costs | | | | | |
| **New ETPL OM&A** | **$ 8,398,625** | **$ 8,566,598** | **$ 8,737,930** | **$ 8,912,688** | **$ 9,090,942** |
| Savings for Customer | $ 668,500 | $ 681,870 | $ 695,507 | $ 709,418 | $ 723,606 |
| **Cumulative Savings** | **$ 2,164,435** | **$ 2,846,305** | **$ 3,541,813** | **$ 4,251,230** | **$ 4,974,836** |

| Distributor OM&A | 2027 | 2028 |
|---|---|---|
| ETPL | $ 7,730,567 | $ 7,885,179 |
| WCHE | $ 2,280,271 | $ 2,325,877 |
| **Total OM&A Status Quo** | **$ 10,010,839** | **$ 10,211,056** |
| OM&A Cost Savings | -$ 738,078 | -$ 752,840 |
| Transition Costs | | |
| **New ETPL OM&A** | **$ 9,272,761** | **$ 9,458,216** |
| Savings for Customer | $ 738,078 | $ 752,840 |
| **Cumulative Savings** | **$ 5,712,914** | **$ 6,465,754** |

Figure 6 below provides a comparison of the capital cost structure among the Parties, *status quo* versus post consolidation.

**Figure 6**

| Distributor Capital | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| ETPL | $3,168,690 | $3,613,205 | $3,360,469 | $3,427,678 | $3,496,232 |
| WCHE | $1,025,600 | $619,000 | $631,380 | $644,008 | $656,888 |
| **Total Capital Spend Status Quo** | **$4,194,290** | **$4,232,205** | **$3,991,849** | **$4,071,686** | **$4,153,120** |
| Capital Spending Reduction | -$300,000 | -$325,000 | -$165,000 | -$161,700 | -$158,466 |
| Capital Transition Costs | $0 | $100,000 | | | |
| **New ETPL Capital** | **$3,894,290** | **$4,007,205** | **$3,826,849** | **$3,909,986** | **$3,994,654** |
| Savings for Customer | $300,000 | $225,000 | $165,000 | $161,700 | $158,466 |
| **Cumulative Savings** | **$300,000** | **$525,000** | **$690,000** | **$851,700** | **$1,010,166** |

| Distributor Capital | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|
| ETPL | $3,566,157 | $3,637,480 | $3,710,229 | $3,784,434 | $3,860,123 |
| WCHE | $670,026 | $683,426 | $697,095 | $711,036 | $725,257 |
| **Total Capital Spend Status Quo** | **$4,236,182** | **$4,320,906** | **$4,407,324** | **$4,495,470** | **$4,585,380** |
| Capital Spending Reduction | -$155,297 | -$152,191 | -$149,147 | -$146,164 | -$143,241 |
| Transition Costs | | | | | |
| **New ETPL Capital** | **$4,080,886** | **$4,168,715** | **$4,258,177** | **$4,349,306** | **$4,442,139** |
| Savings for Customer | $155,297 | $152,191 | $149,147 | $146,164 | $143,241 |
| **Cumulative Savings** | **$1,165,463** | **$1,317,653** | **$1,466,800** | **$1,612,964** | **$1,756,205** |

| Distributor Capital | 2027 | 2028 |
|---|---|---|
| ETPL | $3,937,325 | $4,016,072 |
| WCHE | $739,762 | $754,558 |
| **Total Capital Spend Status Quo** | **$4,677,087** | **$4,770,629** |
| Capital Spending Reduction | -$140,376 | -$137,568 |
| Transition Costs | | |
| **New ETPL Capital** | **$4,536,712** | **$4,633,061** |
| Savings for Customer | $140,376 | $137,568 |
| **Cumulative Savings** | **$1,896,581** | **$2,034,149** |

## OM&A COST PER CUSTOMER PER YEAR FOR THE CONSOLIDATING PARTIES

Figure 7 below provides a comparison of the OM&A cost per customer per year among the Parties. The data supporting this comparison is based on the 2014 to 2016 OEB Yearbook of Electricity Distributors and 2017 projected values.

**Figure 7**

| | ETPL | | | WCHE | | | Combined | | |
|---|---|---|---|---|---|---|---|---|---|
| | OM&A | Customer Count | OM&A Per Customer | OM&A | Customer Count | OM&A Per Customer | OM&A | Customer Count | OM&A Per Customer |
| 2014 | $ 5,651,479.92 | 18,265 | $ 309.42 | $ 1,709,900.00 | 3,797 | $ 450.33 | $ 7,361,379.92 | 22,062 | $ 333.67 |
| 2015 | $ 5,856,835.19 | 18,434 | $ 317.72 | $ 1,762,372.00 | 3,812 | $ 462.32 | $ 7,619,207.19 | 22,246 | $ 342.50 |
| 2016 | $ 6,114,840.38 | 18,637 | $ 328.10 | $ 1,833,938.00 | 3,829 | $ 478.96 | $ 7,948,778.38 | 22,466 | $ 353.81 |
| 2017 | $ 6,181,909.05 | 19,156 | $ 322.72 | $ 1,870,616.76 | 3,745 | $ 499.50 | $ 8,052,525.81 | 22,901 | $ 351.63 |

## CHANGE OF CONTROL

The Applicants are proposing a transaction whereby ERTH will acquire WCHEI, which will then be immediately amalgamated with ETPL into a single distributor. Accordingly, the Applicants confirm that there will be a change of control of WCHEI to effect the consolidation.

## OPERATION OF THE DISTRIBUTION SYSTEM

The Applicants undertook a principled approach in the design of the consolidated utility. Planning for the consolidation has focused on the following key principles:

- Management – Management will fulfill its fiduciary obligations to the corporation, including respecting the interests of ratepayers;
- Customers – Customers will be the operational priority of ETPL following the merge, including the provision of superior customer service, ease of access, and a safe and reliable distribution system;
- Employees – Employees will be treated in a fair and equitable manner. They will adhere to an established set of core values, including work place safety, high customer service standards and improved productivity;
- Community – ETPL will continue to play a significant role in the communities that it serves, be a good corporate citizen through community engagement and facilitate economic development;
- Environmental Stewardship – ETPL will continue to exhibit responsible stewardship, including a strong commitment to energy conservation and environmental sustainability;
- Growth – Growth opportunities will be pursued where prudent; and

The Applicants understand that to achieve the necessary and desired customer and financial outcomes, effective operational processes and skilled employees must be in place to support and deliver on results.

### Operational Focus

Following the merger, ETPL will implement its business mission and vision by focusing on four operating strategies:

- Enhancing service delivery to customers;
- Enhancing internal operational cost efficiencies and asset utilization;
- Increasing shareholder value through growth and productivity improvements; and
- Developing and maintaining highly skilled and motivated employees.

## Employee Focus

ETPL's most important resource following the amalgamation will be its employees. There will be human resource redundancies as a result of consolidating the two LDCs, given that each of the two have similar business purposes and functions. Nonetheless, ETPL will focus on four key areas after the amalgamation to ensure that employees are fully engaged and contributing at their peak:

- Safe and healthy workplace;
- Employee skill development;
- Effective internal corporate communications; and
- Performance based culture.

There are significant employee opportunities as a result of the consolidation including:

- Product and service innovation for employees to develop new skills and to be at the leading edge of technology and service innovation;
- Access to increased training and development opportunities across the organization and the ability to further enhance their skills through corporate-wide training programs;
- Continuity of the workforce, the merger will facilitate a positive transition of attrition over the next few years

## Distribution System Operations

Following the merger, ETPL will initially have three distinct operating regions:

- South Region: Aylmer, Belmont and Port Stanley served by Aylmer operations centre
- Central Region: Ingersoll, Beachville, Thamesford, Embro, Tavistock, Norwich, Otterville and Burgessville served by Ingersoll operations centre; and
- North Region: Goderich, Clinton, Mitchell and Dublin served by Goderich operations centre.

In developing ETPL's operational organizational structure, primary considerations were efficiency, effectiveness, and service levels. Not all job functions within the utility are directly tied to the regions they serve. In fact, several services can be performed centrally without any degradation of efficiency, effectiveness, and service levels. Centralizing certain functions, such as finance, regulatory, billing, call centre control room and IT services, is expected to leverage skill sets, create scale and lower costs which is a fundamental objective of the consolidation.

**Service Centres**

Following ther amalgamation, ETPL will utilize three of the existing four service centres for de-centralized functions such as construction and maintenance, trouble response, logistics and metering. The three service centres proposed post transaction are currently located within the three regions:

- South Region
  - Aylmer;
- Central Region
  - Ingersoll; and
- Eastern Region
  - Goderich.

With the exception of moving ETPL's Mitchell operations centre to Goderich, from a service standpoint, very little, if anything, is changing with regard to service centres and the employees who are located at these locations. No reduction of service levels is anticipated as a result of the consolidation.

**Call Centre/Control Room Consolidation**

One call centre will be designated for ETPL, located in Ingersoll.

One control room will be designated for ETPL, located in Ingersoll.

**Office Location**

Upon the completion of the consolidation, ERTH will operate out of the following office locations:

- The head office and control for ETPL will be located at 143 Bell Street, Ingersoll, Ontario. This location is central to LDC Co's new service area, is readily accessible by multiple highways, is nearly equidistant from ETPL's two operation centres, which maximizes efficiency of interaction and travel.

- The corporate head office of ERTH will be located at 180 Whiting Street, Ingersoll, Ontario, providing corporate services to ETPL. In addition, ERTH's electricity sector affiliate businesses have office locations in London, Ontario and Toronto, Ontario. These offices will continue to support the non-regulated business.

## Information Technology ("IT")

ETPL will set the following IT objectives for business applications:

- Establish a stable, consolidated, secure information technology infrastructure environment to sustain the operations of the new company and minimize operational risk during the transition period following the consolidation;
- Consolidate the Customer Information Systems ("CIS") environment as quickly as possible into one common Harris Northstar system to facilitate integration of Customer Service business functions and improve service to customers;
- Consolidate the Geographic Information Systems ("GIS") and Outage Management Systems ("OMS") into one common Intergraph GIS and OMS environment to facilitate integration of the electrical Network Operations of the business and improve service to customers;
- Consolidate the Financial System into one common environment
- Consolidate the Advanced Metering Infrastructure (AMI) and Operational Data Store (ODS) into one common environment. Both ETPL and WCHEI share a common vendor with regard to AMI infrastructure (Elster); and
- Consolidate enterprise cyber security practices and technologies into a single common set of processes and systems that provides the protection of information and the entire information technology architecture to support all business and regulatory requirements of the new company.

There are a number of less compatible systems that will need to be integrated as part of a transitional plan. Each of these systems may be run in parallel until such time as integration plans can be executed.

Overall, it appears that the high level of systems compatibility between the utilities will facilitate a seamless transition to a common approach to delivering business applications while supporting continuing business operations and managing risk.

## Customer Service

Key elements of the consolidation will focus on customer service. Customers are the operational priority and will continue to receive excellent service. Following the merger, ETPL will ensure a highly reliable, effective, and efficient electricity distribution system as well as innovative, value-added, energy services and solutions. Customers will have access to customer service in a timely, reliable and accurate manner. ETPL will be operated on customer-centric values, and it will undertake a principled approach in the design of an effective organization plan such that customer service responsiveness levels target improvement but will certainly be no less than service levels prior to merging in each community. Adopting best practices and finding efficiencies while maintaining or improving customer service will be a key priority.

ETPL will focus on five attributes within the customer perspective. Initiatives will be identified and organized to target improvement in the following five areas:

- Efficiency, i.e., distribution rates/price;
- Electricity reliability;
- Bill accuracy and quality;
- Responsiveness/ease of doing business; and
- Trust/corporate image.

The objectives and business principles contemplate enhanced customer service delivery as a result of the merger transaction. As such, customer service operational plans will be closely linked to the achievement of customer service satisfaction levels. In setting performance targets for customer service levels following the merger, ETPL will consider:

- Present service levels of WCHEI and ETPL and will reconcile to the highest levels among them;
- Service levels required by OEB regulation;
- Competitive benchmarks; and
- Results of customer surveys.

As part of its ongoing operation, ETPL will regularly review the level of customer service support to ensure appropriate levels are maintained.

The Applicants have estimated that sustained operating, maintenance and administration ("OM&A") savings net of transition costs will be approximately $440,000 in year five and beyond. The OM&A budget for ETPL after the merger is therefore anticipated to be approximately 5% lower than the sum of the OM&A budgets for the Parties, three to five years following completion of the consolidation.

## IMPACT OF THE TRANSACTION ON ECONOMIC EFFICIENCY AND COST EFFECTIVE DISTRIBUTION OF ELECTRICITY

The Applicants have determined the cost structure of ETPL as a result of the consolidation based on the best information available and certain assumptions, as provided in Exhibit B, Tab 5, Schedule 1. Realization of synergy savings will depend on a number of factors.

### Synergy Forecast

The total anticipated savings net of transition costs over a nine year rebasing deferral period resulting from the merger of WCHEI and EPTL total approximately $5,700.000 in operating costs and approximately $1,900,000 in avoided capital costs, which represent $7,600,000 in total cash savings. These operating and capital savings will benefit customers through lower rates than the *status quo*, and will benefit shareholders through increased and more stable dividends.

The approximately $1,900,000 in capital savings, net of any transition costs, over the nine year rebasing deferral period arise mainly due to WCHE avoiding a financial system conversion, avoidance of constructing a new service centre in Mitchell Ontario, savings due to the consolidation of fleet and redundancy of vehicles, and IT infrastructure savings.

It is anticipated that ETPL will have sustained net annual operating savings associated with the merger, relative to the *status quo*, of approximately $830,000 in 2024 and beyond driven primarily by attrition due to retirements when consolidating operational staff.

The synergy savings associated with the merger are summarized in Figure 8 below:

**Figure 8**

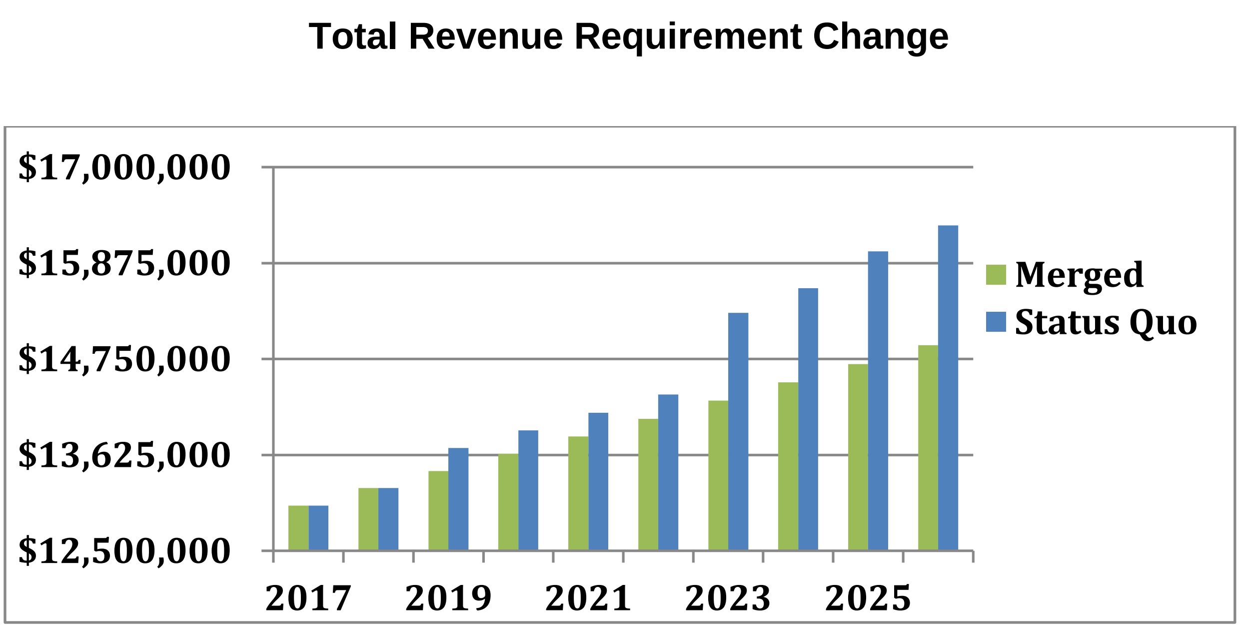
| **Gross Synergies** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Operating | $ - | $ 379,500 | $ 319,500 | $ 369,500 | $ 379,500 | $ 387,090 | $ 394,832 | $ 829,500 | $ 846,090 | $ 863,012 | $ 880,272 | $ 897,877 |
| Capital | $300,000 | $ 325,000 | $ 165,000 | $ 161,700 | $ 158,466 | $ 155,297 | $ 152,191 | $ 149,147 | $ 146,164 | $ 143,241 | $ 140,376 | $ 137,568 |
| **Total** | **$302,017** | **$ 706,518** | **$ 486,519** | **$ 533,220** | **$ 539,987** | **$ 544,409** | **$ 549,046** | **$ 980,671** | **$ 994,279** | **$ 1,008,279** | **$ 1,022,675** | **$ 1,037,474** |
| | | | | | | | | | | | | |
| **Transition costs** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** |
| Operating | $ - | $ 233,089 | $ 101,976 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Capital | $ - | $ 100,000 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Total** | **$ -** | **$ 333,089** | **$ 101,976** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| | | | | | | | | | | | | |
| **Net Synergies** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** |
| Operating | $ - | $ 146,411 | $ 217,524 | $ 369,500 | $ 379,500 | $ 387,090 | $ 394,832 | $ 829,500 | $ 846,090 | $ 863,012 | $ 880,272 | $ 897,877 |
| Capital | $300,000 | $ 225,000 | $ 165,000 | $ 161,700 | $ 158,466 | $ 155,297 | $ 152,191 | $ 149,147 | $ 146,164 | $ 143,241 | $ 140,376 | $ 137,568 |
| **Total** | **$300,000** | **$ 371,411** | **$ 382,524** | **$ 531,200** | **$ 537,966** | **$ 542,387** | **$ 547,023** | **$ 978,647** | **$ 992,254** | **$ 1,006,253** | **$ 1,020,648** | **$ 1,035,446** |

These savings will result in overall lower ETPL electricity distribution rates, in comparison to the rates of the individual LDCs absent the consolidation proposed in this Application. Figures 9 and 10 represent the potential change in revenue requirement to demonstrate the savings between a merger and status quo:

**Figure 9**

| | Merged Revenue Requirement | | | Status Quo Revenue Requirement | | | | |
|---|---|---|---|---|---|---|---|---|
| Total Revenue Requirement | ETPL | WCHE | Total | ETPL | WCHE | Total | Savings | Cumulative Savings |
| 2017 | $10,614,293 | $2,416,936 | $13,031,229 | $10,614,293 | $2,416,936 | $13,031,229 | $ - | $ - |
| 2018 | $10,785,164 | $2,453,190 | $13,238,354 | $10,785,164 | $2,453,190 | $13,238,354 | $ - | $ - |
| 2019 | $10,946,941 | $2,489,988 | $13,436,929 | $10,946,941 | $2,759,623 | $13,706,565 | -$ 269,635 | -$ 269,635 |
| 2020 | $11,111,146 | $2,527,338 | $13,638,483 | $11,111,146 | $2,801,017 | $13,912,163 | -$ 273,680 | -$ 543,315 |
| 2021 | $11,277,813 | $2,565,248 | $13,843,061 | $11,277,813 | $2,843,033 | $14,120,845 | -$ 277,785 | -$ 821,100 |
| 2022 | $11,446,980 | $2,603,726 | $14,050,706 | $11,446,980 | $2,885,678 | $14,332,658 | -$ 281,952 | -$1,103,051 |
| 2023 | $11,618,685 | $2,642,782 | $14,261,467 | $12,362,738 | $2,928,963 | $15,291,702 | -$1,030,235 | -$2,133,286 |
| 2024 | $11,792,965 | $2,682,424 | $14,475,389 | $12,609,993 | $2,972,898 | $15,582,891 | -$1,107,502 | -$3,240,788 |
| 2025 | $11,969,859 | $2,722,660 | $14,692,520 | $12,862,193 | $3,151,272 | $16,013,465 | -$1,320,945 | -$4,561,733 |
| 2026 | $12,149,407 | $2,763,500 | $14,912,908 | $13,119,437 | $3,198,541 | $16,317,978 | -$1,405,070 | -$5,966,803 |

**Figure 10**



## Benefits

*Overview*

The Applicants anticipate that as a result of the consolidation, the following material savings will be generated (values are pre-tax):

- Aggregate gross OM&A savings of $6,050,000 in ETPL over the first nine years following consolidation, or 6,6% of total OM&A expenditures, thereafter continuing at a savings rate of approximately 7.4% annually, (i.e., not cumulative).

- Aggregate gross capital expenditure (“CapEx”) savings of $2,000,000 in ETPL over the first nine years following consolidation, thereafter continuing at a sustained level of $140,000 annually.

ETPL will incur transition costs of approximately $435,000, primarily in the first two years following consolidation, with respect to systems and process integration and human resource costs.

In total, ETPL will deliver approximately $7,600,000 of net cash savings (pre-tax) in the first nine years following the consolidation thereafter sustained at approximately $879,000 per year.

The shareholder and customer benefits described herein are made available by the operating synergies and savings previously described and summarized in Figure 8 above.

The annual operating and capital savings are expected to be sustainable following the nine year period post consolidation. ETPL customers following the merger will benefit from reduced rates as compared to the rates that would have existed if the merger transaction had not occurred. Customers also benefit from a larger and more stable utility that has significant access to investment capital to support sustainable investment in the reliable and safe distribution of electricity.

Based on OEB policy for distributor consolidation, the cost savings and synergies resulting from a consolidation may be retained by shareholders and customers of LDCs as follows:

- Savings net of transaction and transition costs may be retained by shareholders until the next LDC rate rebasing, which must occur no later than the beginning of the eleventh year following the merger. Consequently, LDC shareholders may retain merger benefits for a maximum nine year period subsequent to a merger. The benefits retained in the final three year period are subject to an earnings sharing mechanism;

- The merger benefits the customers in the form of lower distribution rates at the time of the first rebasing of ETPL after the amalgamation as well as during the deferral period through avoided cost of service increases for each separate entity, as demonstrated in Figures 9 and 10 above.

The Applicants have chosen to rebase LDC Co in the tenth year following the completion of the consolidation.

*Customer Benefits*

Customers generally benefit from lower rates from, or very near to, the commencement of a merger transaction.

According to OEB policy with respect to rate making associated with LDC consolidations, the savings corresponding to LDC consolidations are transferred to customers at the first rebasing. The period prior to such first rebasing is defined as the Rebasing Deferral Period.

Notwithstanding the above, customers will benefit significantly through the period leading up to the first rate rebasing.

In the absence of the proposed consolidation, the Parties would continue to regularly rebase their rates, through successive COS applications (further described below) in order to recover ongoing increases in their cost structures. Under the merger, no such rebasing occurs during the Rebasing Deferral Period during which the savings accrue to shareholder interests. Consequently, as a result of the proposed consolidation (and consolidations generally), customers benefit from relatively lower rates during the Rebasing Deferral Period.

The overall relative benefit to customers under the “Merged” versus “Status Quo” scenarios is illustrated in Figure 9 above.

Overall, the proposed consolidation is also expected to deliver lower distribution costs to LDC Co customers averaging an aggregate of:

- $647,000 per year, or 6.3%, through the entire Forecast Period.

- $635,000 per year, or 6.2%, through the Rebasing Deferral Period.

- $753,000 per year, or 7.4%, following a transfer of merger benefits to customers in 2028.

# INCREMENTAL COSTS FOR PARTIES TO THE TRANSACTION

## Incremental Consolidation Costs

The Parties to the proposed consolidation have incurred and will incur incremental costs in respect of the proposed consolidation. Consolidation costs include, but are not limited to: due diligence on the part of all Parties; due diligence to negotiate the terms of the consolidation; costs associated with all regulatory, legal and statutory reviews in order to receive necessary regulatory approvals; integration costs of IT systems including CIS systems and other technology-related support systems; integration of operational systems including GIS, OMS and Supervisory Control and Data Acquisition ("SCADA") systems; integration of customers; alignment of financial and regulatory reporting processes; staff related costs and transition of assets and related management to one standard.

The aggregate consolidation costs are approximately $435,000. The costs associated with the above-mentioned transition and consolidation requirements will be funded through the anticipated productivity savings expected from the consolidation during the nine year rebasing deferral period; they will not be included in the ratepayer funded ETPL revenue requirement following consolidation.

## Incremental Costs

*Transaction Development Costs*

Each of the Applicants retained its own independent legal and financial advisors. Additionally, the Applicants engaged joint financial advisors to facilitate the valuation of the Parties. Such costs are borne by each of the Applicants and do not carry into the new merged entity. These costs are not recoverable by the Applicants through electricity distribution rates.

*Implementation/Integration Costs*

As with the transaction development costs, these transitional costs will be financed through the anticipated productivity savings expected from the transaction during the rebasing deferral period; they will not be financed through distribution rates. The deferred rebasing of ETPL will allow the consolidated entity to retain synergy savings to offset consolidation costs and provide shareholder incentives to undertake the merger, while protecting the interests of customers across all of the existing service areas.

The following Tables 11 and 12 summarize the savings and costs for OM&A and Capital:

**Figure 11**

| Distributor OM&A | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| ETPL | $ 6,181,909 | $ 6,468,593 | $ 6,597,965 | $ 6,729,924 | $ 6,864,523 |
| WCHE | $ 1,870,617 | $ 1,908,029 | $ 1,946,190 | $ 1,985,113 | $ 2,024,816 |
| **Total OM&A Status Quo** | **$ 8,052,526** | **$ 8,376,622** | **$ 8,544,155** | **$ 8,715,038** | **$ 8,889,338** |
| OM&A Cost Savings | $ - | -$ 344,500 | -$ 394,500 | -$ 498,500 | -$ 593,500 |
| Transition Costs | | $ 233,089 | $ 101,976 | | |
| **New ETPL OM&A** | **$ 8,052,526** | **$ 8,265,211** | **$ 8,251,631** | **$ 8,216,538** | **$ 8,295,838** |
| Savings for Customer | $ - | $ 111,411 | $ 292,524 | $ 498,500 | $ 593,500 |
| **Cumulative Savings** | | **$ 111,411** | **$ 403,935** | **$ 902,435** | **$ 1,495,935** |

| Distributor OM&A | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|
| ETPL | $ 7,001,813 | $ 7,141,849 | $ 7,284,686 | $ 7,430,380 | $ 7,578,988 |
| WCHE | $ 2,065,312 | $ 2,106,618 | $ 2,148,751 | $ 2,191,726 | $ 2,235,560 |
| **Total OM&A Status Quo** | **$ 9,067,125** | **$ 9,248,468** | **$ 9,433,437** | **$ 9,622,106** | **$ 9,814,548** |
| OM&A Cost Savings | -$ 668,500 | -$ 681,870 | -$ 695,507 | -$ 709,418 | -$ 723,606 |
| Transition Costs | | | | | |
| **New ETPL OM&A** | **$ 8,398,625** | **$ 8,566,598** | **$ 8,737,930** | **$ 8,912,688** | **$ 9,090,942** |
| Savings for Customer | $ 668,500 | $ 681,870 | $ 695,507 | $ 709,418 | $ 723,606 |
| **Cumulative Savings** | **$ 2,164,435** | **$ 2,846,305** | **$ 3,541,813** | **$ 4,251,230** | **$ 4,974,836** |

| Distributor OM&A | 2027 | 2028 |
|---|---|---|
| ETPL | $ 7,730,567 | $ 7,885,179 |
| WCHE | $ 2,280,271 | $ 2,325,877 |
| **Total OM&A Status Quo** | **$ 10,010,839** | **$ 10,211,056** |
| OM&A Cost Savings | -$ 738,078 | -$ 752,840 |
| Transition Costs | | |
| **New ETPL OM&A** | **$ 9,272,761** | **$ 9,458,216** |
| Savings for Customer | $ 738,078 | $ 752,840 |
| **Cumulative Savings** | **$ 5,712,914** | **$ 6,465,754** |

Figure12

| Distributor Capital | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| ETPL | $3,168,690 | $3,613,205 | $3,360,469 | $3,427,678 | $3,496,232 |
| WCHE | $1,025,600 | $619,000 | $631,380 | $644,008 | $656,888 |
| **Total Capital Spend Status Quo** | **$4,194,290** | **$4,232,205** | **$3,991,849** | **$4,071,686** | **$4,153,120** |
| Capital Spending Reduction | -$300,000 | -$325,000 | -$165,000 | -$161,700 | -$158,466 |
| Capital Transition Costs | $0 | $100,000 | | | |
| **New ETPL Capital** | **$3,894,290** | **$4,007,205** | **$3,826,849** | **$3,909,986** | **$3,994,654** |
| Savings for Customer | $300,000 | $225,000 | $165,000 | $161,700 | $158,466 |
| **Cumulative Savings** | **$300,000** | **$525,000** | **$690,000** | **$851,700** | **$1,010,166** |

| Distributor Capital | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|
| ETPL | $3,566,157 | $3,637,480 | $3,710,229 | $3,784,434 | $3,860,123 |
| WCHE | $670,026 | $683,426 | $697,095 | $711,036 | $725,257 |
| **Total Capital Spend Status Quo** | **$4,236,182** | **$4,320,906** | **$4,407,324** | **$4,495,470** | **$4,585,380** |
| Capital Spending Reduction | -$155,297 | -$152,191 | -$149,147 | -$146,164 | -$143,241 |
| Transition Costs | | | | | |
| **New ETPL Capital** | **$4,080,886** | **$4,168,715** | **$4,258,177** | **$4,349,306** | **$4,442,139** |
| Savings for Customer | $155,297 | $152,191 | $149,147 | $146,164 | $143,241 |
| **Cumulative Savings** | **$1,165,463** | **$1,317,653** | **$1,466,800** | **$1,612,964** | **$1,756,205** |

| Distributor Capital | 2027 | 2028 |
|---|---|---|
| ETPL | $3,937,325 | $4,016,072 |
| WCHE | $739,762 | $754,558 |
| **Total Capital Spend Status Quo** | **$4,677,087** | **$4,770,629** |
| Capital Spending Reduction | -$140,376 | -$137,568 |
| Transition Costs | | |
| **New ETPL Capital** | **$4,536,712** | **$4,633,061** |
| Savings for Customer | $140,376 | $137,568 |
| **Cumulative Savings** | **$1,896,581** | **$2,034,149** |

## Financing of Incremental Costs

These costs are self-financing by the associated savings.

## VALUATION OF ASSETS AND SHARES

BDO Canada LLP were jointly hired by the Parties to complete a valuation of the issued and outstanding shares of ERTH and WCHEI for purposes of merger negotiations to ensure both entities were valued on a fair and consistent basis.

The value for WCHEI and ETPL was completed on a stand-alone basis using a capitalized cash flow approach. The remainder of ERTH's consolidated and non-regulated entities and assets were valued using a discounted cash flow approach or an adjusted net cash flow approach, as appropriate for the nature of the entity.

## FINANCIAL VIABILITY

The proposed transaction is a non-cash merger and as such there is no adverse effect on the financial viability of the Parties.

## FINANCING OF THE TRANSACTION

As discussed in Exhibit B, Tab 4, Schedules 1-2, the only consideration exchanged in respect of the proposed transaction is the issuance of new shares in ERTH. Therefore, no financing is required upon closing of the consolidation proposed in this Application.

## FINANCIAL STATEMENTS

Copies of the audited financial statements for the past two most recent years for each Party are contained in the attachments shown below.

- Attachment 7 - ETPL 2016 Financial Statements
- Attachment 8 - ETPL 2015 Financial Statements
- Attachment 9 - WCHEI 2016 Financial Statements
- Attachment 10 - WCHEI 2015 Financial Statements

## PRO FORMA FINANCIAL STATEMENTS

A copy of the pro forma financial statements of ETPL following an approved merger with WCHEI is included as Attachment 11.

## DEFERRED REBASING PERIOD

The Applicants have chosen to defer the rebasing for ETPL for Nine (9) years from the date of closing of the proposed transactions, consistent with the Consolidation Policy and the Handbook. Accordingly, the pre-existing rate plans for WCHEI Effective May 1$^{st}$, 2018 (2018 IRM application filed in November of 2017 EB-2017-0093) and ETPL Effective May 1$^{st}$ 2018 (as proposed in its current Cost of Service application, EB-2017-0038) will continue until their expiry and the Parties would maintain Price Cap IR until the end of the Nine year rebasing deferral period. During the rebasing deferral period, ETPL may apply for rate adjustments using the Board's ICM as may be necessary and in accordance with applicable Board policies with respect to eligibility for, and the use of, the ICM.

## EARNINGS SHARING MECHANISM ("ESM")

The Applicants have identified in Exhibit B, Tab 2, Schedule 1, for years six to nine of the rebasing deferral period an ESM proposed by the Applicants that is consistent with the Consolidation Policy. Consequently, ETPL may be subject to an ESM-related rate adjustment after year six following the completion of the consolidation.

Earnings in excess of 300 basis points above the Board's established regulatory return on equity ("ROE") for the consolidated entity would be divided on a 50/50 basis between merged ETPL and its ratepayers. The ratepayer share of earnings will be credited to a newly proposed deferral account, for clearance at the next applicable annual IRM application filing. For example, if merged ETPL over-earned in year six post consolidation, it would report the balance in the deferral account in the year eight IRM application which would be filed in year seven, and refund 50% of this balance to ratepayers over the twelve months commencing May 1st of year eight.

The regulatory net income will be calculated, for the purpose of earnings sharing, in the same manner as net income for regulatory purposes under the RRR filings. The Applicants expect that it will exclude revenue and expenses that are not otherwise included for regulatory purposes, such as, but not limited to:

- The settlement of any regulatory assets/liabilities including the lost revenue adjustment mechanism ("LRAM");
- Changes in taxes/PILs to which Account 1592 applies, which will be shared through that account rather than through earnings sharing;
- Revenue collected from any ICM recovery rate riders;
- Rate of Return on Monthly Billing capital and operating implementation costs should LDCs be permitted to recover these costs from ratepayers; and
- Donations.

For the purpose of the ESM calculation, the nature and timing of revenues, expenses, and costs will be consistent with the regulatory rules in effect at the end of the rebasing deferral period for the calculation of revenue requirement on a cost of service basis.

For clarity, merged ETPL would begin reporting on the ROE outcome for ESM purposes commencing in year seven post consolidation, when audited results for year six are available.

## OTHER RELATED MATTERS

(a) Implementation of New or Extension of Existing Rate Orders

Please refer to Exhibit B, Tab 2, Schedule 1 for: i) the schedules of the existing Rate Orders for each of the Parties; and ii) the treatment of Rate Orders for ETPL after the merger. Copies of such Rate Orders are included as Attachment 12.

(b) Transfer of Rate Orders and Licences

Please refer to Exhibit B, Tab 2, Schedule 1, OEB Approvals Sought, for the request to transfer the rate orders and licence of the Parties to WCHEI to ETPL.

(c) Licence Amendment and Cancellation

Please refer to Exhibit B, Tab 2, Schedule 1, OEB Approvals Sought, for the request to cancel the existing WCHEI licence and amend the existing ETPL licence to include the former WCHEI service area.

(d) Deferral and Variance Accounts

Please refer to Exhibit B, Tab 2, Schedule 1, for the request to continue to track costs to the deferral and variance accounts currently approved by the OEB for the Parties.

(e) Specification of Accounting Standards

All of the Parities have adopted IFRS. The Parties currently prepare their financial statements under IFRS; merged ETPL will also be preparing its financial statements under IFRS.

ETPL will utilize MIFRS after amalgamation for regulatory accounting purposes, consistent with OEB policy.

**ATTACHMENT 1**

**ADMINISTRATIVE - IDENTIFICATION OF THE PARTIES**

## Name of Applicant 1

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Erie Thames Powerlines Corporation
143 Bell Street
P.O. Box 157
Ingersoll, ON N5C 3K5

## Authorized Representative

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**Chris White**

President
Erie Thames Powerlines Corporation
143 Bell Street
P.O. Box 157
Ingersoll, ON N5C 3K5
Phone: (519) 485-1820 x 235
Email: OEB@eriethamespower.com

## Name of Applicant 2

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West Coast Huron Energy Inc.
57 West Street
Goderich, ON
N7A 2K5

## Authorized Representative

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**Larry McCabe**

President
West Coast Huron Energy Inc.
57 West Street
Goderich, ON
N7A 2K5
Phone:  (519) 524-8344
Email:  lmccable@goderich.ca

## Counsel to the Applicants

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**Tyler J. Moore, LL.B.**

486 Princess Avenue
London, ON N6B 2B6
Phone:  (226) 926-8654
Email:  Tyler.Moore@ERTHCorp.com

# Attachment 2

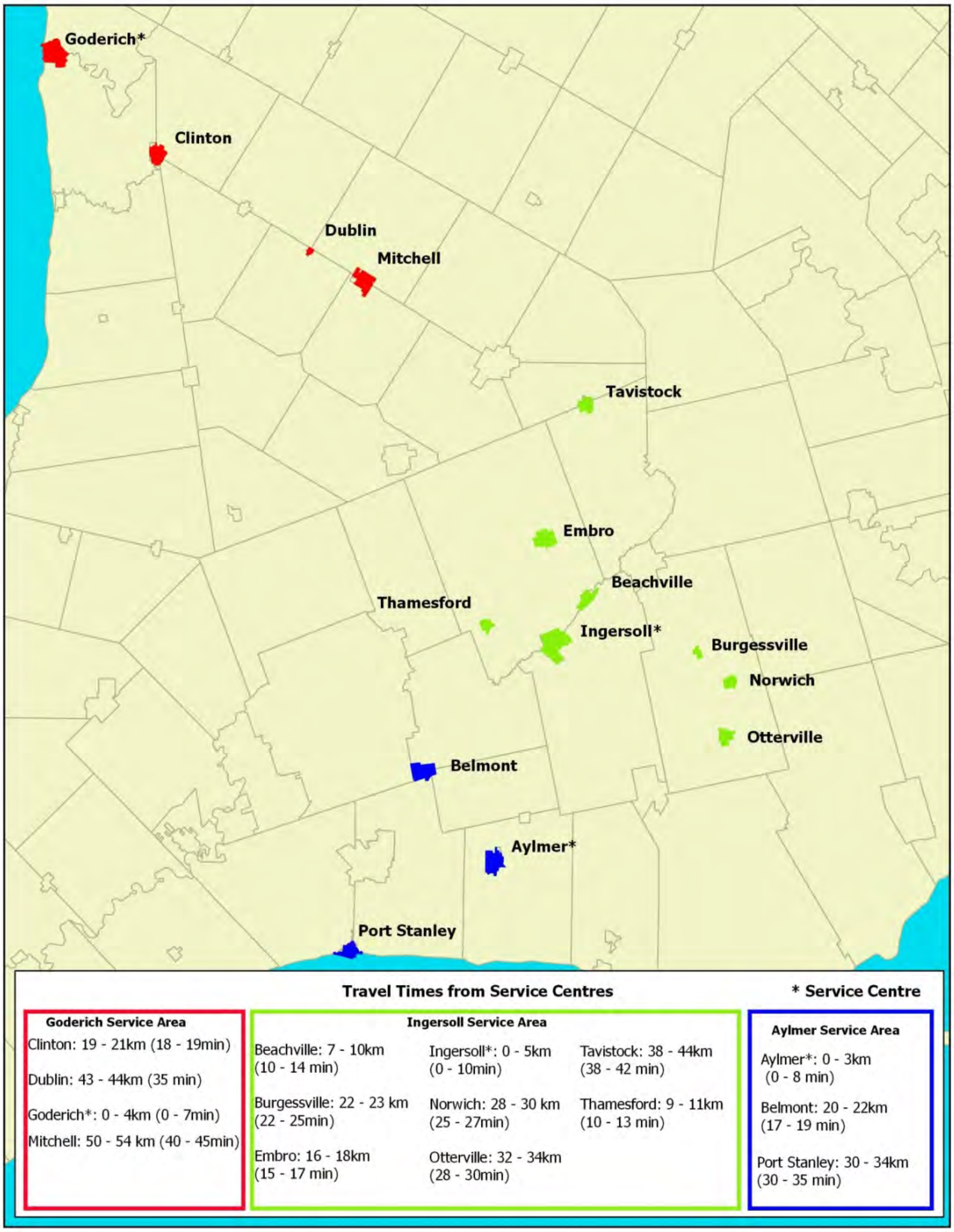
## West Coast Hydro Service Territory

# Attachment 3

## Erie Thames Powerlines Service Territory

# Attachment 4

## Proposed Service Centres with Travel Times



# ATTACHMENT 5

# SHARE PURCHASE AGREEMENT

# ATTACHMENT 5

# SHARE PURCHASE AGREEMENT

THIS SHARE PURCHASE AGREEMENT is made the 11th day of December, 2017.

**B E T W E E N:**

**THE CORPORATION OF THE TOWN OF GODERICH**, a municipality located in the Province of Ontario (the "Vendor")

-and-

**ERTH CORPORATION**, a corporation incorporated under the laws of the Province of Ontario (the "Purchaser")

**WHEREAS:**

A. The Vendor is the registered and beneficial owner of all of the issued and outstanding shares in the capital of West Coast Huron Energy Inc. (the "Company")

B. The Vendor wishes to sell to the Purchaser and the Purchaser wishes to purchase from the Vendor all of the shares in the Company upon the terms and conditions set forth in this Agreement.

C. As consideration for the Company Shares, the Vendor will receive a number of shares in the capital of the Purchaser, pursuant to the terms and conditions in this Agreement.

D. Immediately upon the closing of the transactions described above, the Company will be amalgamated with Erie Thames Powerlines Corporation, a wholly-owned subsidiary of the Purchaser, pursuant to an amalgamation agreement described herein.

**NOW THEREFORE** that in consideration of the premises and the covenants, agreements, warranties and payments hereinafter set forth, and for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties agree as follows:

## 1. DEFINITIONS AND INTERPRETATION

### 1.1. Definitions

In this Agreement, unless something in the subject matter or context is inconsistent therewith:

1.1.1. **"Agreement"** means this share purchase agreement and any instrument amending this Agreement; "hereof", "hereto", "hereunder" and similar expressions mean and refer to this Agreement and not to a particular article or section and the expression "Article" or

"Section" followed by a number means and refers to the specified Article or Section of this Agreement.

1.1.2. **"Amalgamation"** means the amalgamation of the Company and Erie Thames Powerlines.

1.1.3. **"Amalgamation Agreement"** means the definitive legal agreement consummating the Amalgamation in the form annexed hereto as Schedule 1.1.3.

1.1.4. **"Business"** or **"Businesses"** mean the business or businesses currently and previously carried on by the Company or ERTH, as applicable, consisting of,

(a) In the case of the Company, a licensed distributor of electricity within its licensed service area; and

(b) In the case of the Purchaser, a holding company owning shares in and providing oversight and management of:

(i) Erie Thames Powerlines Corporation, a licensed distributor of electricity within its licensed service area; and

(ii) the non-regulated Subsidiaries described in Schedule 1.2.56.

1.1.6. **"Business Day"** means a day other than a Saturday, Sunday or statutory holiday in the Province of Ontario.

1.1.7. **"Claim"** means any act, omission or state of facts, and any Legal Proceeding, assessment, judgment, settlement or compromise relating thereto, which may give rise to a right to indemnification under Sections 12.3 or 12.4.

1.1.8. **"Closing"** means the completion of the transactions contemplated herein, including sale by the Vendor to the Purchaser of the Company Shares, and the issuance of the ERTH Shares to the Vendor.

1.1.9. **"Closing Date"** means January 1, 2018, if all the conditions described in Section 8.1 and Section 9.1 have been satisfied or waived by the relevant Party in advance of such date or a date no later than thirty (30) days following the receipt of all Required Regulatory Approvals if the Required Regulatory Approvals are not received before the Closing Date, or such other date as may be agreed by the Parties.

1.1.10. **"Closing Date Financial Statements"** means the audited financial consolidated statements for the Company and/or the Purchaser, as applicable, for the fiscal period ending December 31, 2017.

1.1.11. **"Closing Document"** means any agreement, certificate, instrument, affidavit, statutory declaration or other document delivered or given pursuant to this Agreement at or subsequent to the Closing.

1.1.12. **"Company"** means West Coast Huron Energy Inc., an LDC that is wholly-owned by the Vendor.

1.1.13. **"Company Promissory Note"** means the promissory note between the Vendor and the Company, a copy of which is annexed hereto as Schedule 1.1.13.

1.1.14. **"Company Shares"** means all of the issued and outstanding shares in the capital of the Company.

1.1.15. **"Consents and Approvals"** means all consents and approvals required to be obtained in connection with the execution and delivery of this Agreement and the completion of the transactions contemplated by this Agreement, and includes, without limitation, resolutions of the municipal councils of the Vendor and the Purchaser, as applicable, authorizing and approving the transactions contemplated by this Agreement.

1.1.16. **"Direct Claim"** means any claim asserted against an Indemnitor by an Indemnitee which does not result from a Third Party Claim.

1.1.17. **"Electricity Act"** means the *Electricity Act* (Ontario).

1.1.18. **"Employee Benefits"** means:

(a) salaries, wages, bonuses, vacation entitlements, commissions, fees, stock option plans, stock purchase plants, incentive plans, deferred compensation plans, profit sharing plans and other similar benefits, plans or arrangements;

(b) insurance, health, welfare, disability, pension, retirement, travel, hospitalization, medical, dental, legal, counselling, eye care and other similar benefits, plans or arrangements; and

(c) agreements or arrangements with any labour union or employee association, written or oral employment agreements or arrangements and agreements or arrangements for the retention of the services of independent contractors, consultants or advisors.

1.1.19. **"Employees"** means all individuals employed by the Company or ERTH, as applicable, and, for greater certainty, includes those employees on short term disability leave, long term disability leave, absent on authorized leave under the *Workplace Safety and Insurance Act* (Ontario) or the *Employment Standards Act* (Ontario) or otherwise absent.

1.1.20. **"Encumbrances"** means any pledge, lien, charge, assignment by way of security, security agreement, conditional sale agreement, security interest, deed of trust, title retention agreement, mortgage, restriction, development or similar agreement, easement, right-of-way, title defect, option or adverse claim, certificate of pending litigation or encumbrance or any other rights of others of any kind or character whatsoever.

1.1.21. **"Environmental Laws"** means all Laws relating in full or in part to the protection of the environment, and includes, without limitation, those Laws relating to the storage, generation, use, handling, manufacture, processing, transportation, treatment, presence, release, management, and disposal of Hazardous Substances, waste, pollutants or contaminants.

1.1.22. **"Erie Thames Powerlines"** means Erie Thames Powerlines Corporation, an LDC that is wholly-owned by the Purchaser.

1.1.23. **"ERTH"** means the Purchaser and its Subsidiaries.

1.1.24. **"ERTH Shares"** means the Voting Share and the Payments Shares, collectively.

1.1.25. **"Final Tax Returns"** has the meaning ascribed thereto in Section 11.2.

1.1.26. **"Financial Statements"** means the financial statements upon which the Valuation was based, which include, as applicable:

(a) the audited financial statements of the Company as at December 31, 2015 consisting of a balance sheet of the Company as at December 31, 2015 and the accompanying statements of changes in financial position, operations and retained earnings for the 12 month period then ended, a copy of which is annexed hereto as Schedule 1.1.26(a); or

(b) the audited financial statements of the Purchaser as at December 31, 2015 consisting of the balance sheet of the Purchaser as at December 31, 2015 and the accompany statements of changes in financial position, operations and retained earnings for the 12 month period then ended, a copy of which is annexed hereto in Schedule 1.1.26(b).

1.1.27. **"Governmental Authority"** means any municipal, provincial, or federal government authority, including, without limitation, the OEB, any governmental department, agency, commission, board, tribunal, crown corporation, or court or other law, rule or regulation-making entity having or purporting to have powers of statutory enforcement, jurisdiction on behalf of Canada, or any province or other subdivision thereof or any municipality, district or other subdivision thereof.

1.1.28. **"Hazardous Substance"** means any substance or material, including petroleum and its by-products, asbestos, PCBs and any material or substance which is defined as a hazardous waste, hazardous substance, hazardous material, restricted hazardous waste, toxic waste, toxic substance, toxic or pollutant, a deleterious substance, a contaminant or source of pollution or contamination considered as such under any provision of Environmental Laws or by any Governmental Entity.

1.1.29. **"IFRS"** has the meaning ascribed thereto in Section 1.3 herein.

1.1.30. **"Income Tax Act"** means the *Income Tax Act* (Canada).

1.1.31. **"Indemnitee"** means any Party entitled to indemnification under this Agreement.

1.1.32. **"Indemnitor"** means any Party obligated to provide indemnification under this Agreement.

1.1.33. **"Indemnity Payment"** means any amount of a Loss required to be paid pursuant to Sections 12.3 or 12.4.

1.1.34. **"Independent Accountant"** has the meaning ascribed thereto in Section 4.1.2

1.1.35. **"Laws"** means all applicable laws, statutes, by-laws, rules, regulations, orders and ordinances together with all binding codes, guidelines, policies, notices, directions, directives, standards, licenses, permits, approvals, judgments, injunctions, awards and decrees or other requirements of any Governmental Authority and includes, without limitation, Environmental Laws.

1.1.36. **"LDC"** means an OEB-licensed, local electricity distribution company.

1.1.37. **"Legal Proceeding"** means any litigation, demand, action, suit, investigation, hearing, claim, complaint, grievance, arbitration proceeding or any other proceedings in any form whatsoever, including without limitation, proceedings initiated by or conducted by or before any provincial or federal court, the OEB, the Workplace Safety and Insurance Board, the Human Rights Commission or Tribunal, the Ontario Ministry of Labour, or any other federal, provincial, municipal or other Governmental Authority, department, self regulatory organization, commission, board, bureau, agency or instrumentality, domestic or foreign, or in respect of any Employee Benefits or Pension Plan and includes any appeal or review and any application for same.

1.1.38. **"Letter of Intent"** means the letter of intent from ERTH dated June 6, 2017 and accepted by the Vendor and the Company on July 17, 2017, a copy of which is attached as Schedule 1.1.38 hereto.

1.1.39. **"Licenses and Permits"** means all licenses, registrations, qualifications, permits, filings, authorizations, exemptions, consents and approvals required by the Company and ERTH, as applicable, to carry on its respective Businesses.

1.1.40. **"Loss"** means any and all loss, liability, damage, cost, expense, charge, fine, penalty or assessment, resulting from or arising out of any Claim, including the costs and expenses of any Legal Proceeding, assessment, judgment, settlement or compromise relating thereto and all interest, punitive damages, fines and penalties and reasonable legal fees and expenses incurred in connection therewith, including loss of profits and consequential damages.

1.1.41. **"Material Contracts"** means the contracts, agreements, instruments and other legally binding commitments or arrangements, written or oral, entered into by the Company or ERTH, as applicable.

1.1.42. **"Merged LDC"** means the LDC established upon the Amalgamation of the Company and Erie Thames Powerlines.

1.1.43. **"OEB"** means the Ontario Energy Board.

1.1.44. **"OEB Act"** means the *Ontario Energy Board Act* (Ontario).

1.1.45. **"Officer's Certificates"** has the meaning ascribed thereto in Section 4.2 herein.

1.1.46. **"Online Data Room"** means an online data portal set up by the Parties where due diligence and other documentation regarding the Company and the Purchaser.

1.1.47. **"Parties"** means the Vendor and the Purchaser, and **"Party"** means any of them.

1.1.48. **"Payment Shares"** means Six Million, Ninety Five Thousand, Nine Hundred and Twenty Four (6,095,924) Class B shares in the capital of the Purchaser to be issued to the Vendor on the Closing Date, the attributes of which are annexed hereto as Schedule 1.1.48.

1.1.49. **"PCB"** means polychlorinated biphenyls.

1.1.50. "**Pension Plan**" means as applicable to the Employees of the Company and ERTH, the Ontario Municipal Employees Retirement System, as constituted under the *Ontario Municipal Employees Retirement System Act* (Ontario).

1.1.51. **"Purchaser"** means ERTH Corporation.

1.1.52. **"Real Property"** means all real property owned by the Company or ERTH, as applicable, and includes all plant, buildings, structures, erections, improvements, appurtenances and fixtures situate thereon or forming part thereof.

1.1.53. **"Required Regulatory Approvals"** mean all those applications, notices, orders, licenses, consents and approvals of and to Governmental Authorities that will be required to complete and give effect to the transactions contemplated in this Agreement including, without limitation, an order by the OEB granting leave to acquire the Company Shares and complete the Amalgamation pursuant to the OEB Act.

1.1.54. **"Shareholder Agreement"** means the unanimous shareholder agreement to which the shareholders of the Purchaser are bound, a copy of which has been disclosed to the Vendor and its authorized representatives.

1.1.55. **"Storage Tanks"** means above or underground tanks, the operation, maintenance, removal and decommissioning of which tanks are regulated pursuant to applicable Environmental Laws.

1.1.56. **"Subsidiaries"** means the Purchaser's wholly-owned subsidiaries on the date of this Agreement, as listed in the corporate chart of the Purchaser set out in Schedule 1.1.56.

1.1.57. **"Tax" or "Taxes"** means all taxes including payments in lieu of taxes, any charges, fees, levies, imposts, and other assessments and charges of any kind whatsoever imposed by any Governmental Authority, including all those levied on income, sales, use, goods and services, value added, capital, capital gains, alternative, net worth, transfer, profits, withholding, payroll, employer health, excise, franchise, real property and personal property taxes, and any other taxes, customs duties, fees, assessments or similar charges in the nature of a tax including the Canada Pension Plan and provincial pension plan contributions, employment insurance premiums and workers' compensation premiums, together with any installments with respect thereto, and any interest, fines and penalties imposed by any Governmental Authority, and whether disputed or not, however, "Tax" or "Taxes" shall not include any Transfer Tax.

1.1.58. **"Tax Legislation"** means, collectively, the Income Tax Act and all federal, provincial, territorial, municipal, foreign, or other statutes imposing a tax, including all treaties, conventions, rules, regulations, orders, and decrees of any jurisdiction.

1.1.59. **"Tax Returns"** means all reports, elections, returns, and other documents required to be filed under the provisions of any Tax Legislation and any Tax forms required to be filed, whether in connection with a Tax Return or not, under any provisions of any applicable Tax Legislation.

1.1.60. **"Third Party Claim"** means any Claim asserted against an Indemnitee that is paid or payable to, or claimed by, any person who is not a Party.

1.1.61. **"Transfer Tax"** means the transfer tax described in subsection 94(1) of the Electricity Act.

1.1.62. **"Valuation"** means the valuation of the Company, Erie Thames Powerlines and the Purchaser's non-regulated Subsidiaries as undertaken by BDO.

1.1.63. **"Vendor"** means the Town of Goderich.

1.1.64. **"Vendor's Solicitors"** means Donnelly Murphy LLP.

1.1.65. **"Voting Share"** means one Class A share in the capital of the Purchaser, the attributes of which are annexed hereto as Schedule 1.1.65.

**1.2. Gender and Number**

In this Agreement words importing a specific gender include all genders and words importing the singular include the plural and vice versa.

**1.3. Accounting Principles**

Wherever in this Agreement, reference is made to international financial reporting standards ("IFRS"), such reference shall be deemed to be to the international financial reporting standards applicable as at the date on which such standards are applied.

**1.4. Headings**

The division of this Agreement into Articles and Sections and the use of a table of contents and headings are for convenience of reference only and shall not affect the interpretation of this Agreement.

**1.5. Contra Proferentem**

Each of the Parties acknowledges that its respective legal counsel has participated in the drafting of this Agreement and that the rule of contra proferentem shall not apply with respect to the interpretation of this Agreement.

**1.6. Knowledge**

(a) Where any representation, warranty or other statement in this Agreement is expressed to be made by the Vendor to its knowledge or is otherwise expressed to be limited in scope to matters known to the Vendor, or of which the Vendor is aware, it shall mean such knowledge as is actually known to, or which would have or should have come to the attention of the Vendor, the Company, and the directors, officers or employees of the Vendor and the Company who have overall responsibility for knowledge of the matters relevant to such statement and the Vendor hereby confirms that it has made appropriate inquiries of all such directors, officers and employees.

(b) Where any representation, warranty or other statement in this Agreement is expressed to be made by the Purchaser and its Subsidiaries, as applicable, to its or their knowledge or is otherwise expressed to be limited in scope to matters known to the Purchaser and its Subsidiaries, or of which the Purchaser and its Subsidiaries is or are aware, it shall mean such knowledge as is actually known to, or which would have or should have come to the attention of the Purchaser and its Subsidiaries, and the directors, officers or employees of the Purchaser and its Subsidiaries who have overall responsibility for knowledge of the matters relevant to such statement and the Purchaser and its Subsidiaries hereby confirm that they have made appropriate inquiries of all such directors, officers and employees.

**1.7. Remedies Cumulative**

Subject to Article 2, the rights, remedies, powers and privileges herein provided to a Party are cumulative and in addition to and not exclusive of or in substitution for any rights, remedies, powers and privileges otherwise available to that Party.

**1.8. Additional Rules of Interpretation**

(a) Unless something in the subject matter or context is inconsistent therewith, references herein to an Article, Section, Subsection, paragraph, clause, Schedule or Exhibit are to the applicable article, section, subsection, paragraph, clause, Schedule or Exhibit of this Agreement.

(b) Wherever the words "include", "includes", or "including" are used in this Agreement or in any closing document, they shall be deemed to be followed by the words "without limitation" and the words following "include", or "including" shall not be considered to set forth and exhaustive list.

(c) The words "hereof", "herein", "hereto", "hereunder", "hereby" and similar expressions shall be construed as referring to this Agreement in its entirety and not to any particular section or portion of it.

(d) Unless otherwise specified, all dollar amounts in this Agreement, including the symbol "$", refer to Canadian currency.

(e) Unless otherwise indicated, all references in this Agreement to any statute include the regulations thereunder and applicable guidelines, bulletins or policies made in connection therewith and which are legally binding, in each case as amended, re-enacted, consolidated or replaced from time to time and in the case of any such amendment, re-enactment, consolidation or replacement, reference herein to a particular provision shall be read as referring to such amended, re-enacted, consolidated or replaced provision.

(f) All references herein to any agreement (including this Agreement), document or instrument mean such agreement, document or instrument as amended, supplemented, modified, varied, restated or replaced from time to time in accordance with the terms thereof and, unless specified therein, includes all schedules and exhibits attached thereto.

(g) Unless the context otherwise requires, references in this Agreement to a "person" are to be broadly interpreted and shall include an individual (whether acting as an executor, administrator, legal representative or otherwise), body corporate, unlimited liability company, partnership, limited liability partnership, joint venture, trust, unincorporated association, unincorporated syndicate, any governmental authority and any other legal or business entity.

(h) The term "ordinary course", when used in relation to the conduct by the Company or ERTH of its respective Business means any transaction which constitutes an ordinary day-to-day business activity, conducted in a commercially reasonable and businesslike manner, having no unusual or special features, and, in the case of the Company and ERTH, consistent with past practice.

(i) The terms "as disclosed" or has "has been disclosed" refers to the Company and Purchaser documents uploaded to the Online Data Room.

(j) Unless otherwise defined herein, words or abbreviations which have well-known trade meanings are used herein with those meanings.

## 2. SCHEDULES

### 2.1. Schedules

The following are the Schedules annexed hereto and incorporated by reference and deemed to be part hereof:

| | |
|---|---|
| Schedule 1.1.3 | - Amalgamation Agreement |
| Schedule 1.1.13 | - Goderich Promissory Note |
| Schedule 1.1.26(a) | - Goderich Hydro 2015 Financial Statements |
| Schedule 1.1.26(b) | - ERTH Corporation Consolidated 2015 Financial Statements |
| Schedule 1.1.38 | - Letter of Intent |
| Schedule 1.1.48 | - Payment Share Attributes |
| Schedule 1.1.56 | - ERTH Corporate Chart |
| Schedule 1.1.65 | - Voting Share Attributes |
| Schedule 11.7 | - Lease Agreement re: 240 Huckins Street, Goderich ON |
| Schedule 11.8 | - Water Billing Agreement |
| Schedule 11.9 | - Street and Traffic Agreement |

## 3. TRANSACTIONS AND CONSIDERATION

### 3.1. Agreement for Purchase and Sale

Upon and subject to the terms and conditions in this Agreement, on the Closing Date:

(a) the Vendor hereby agrees to sell, assign, and transfer to the Purchaser, and the Purchaser hereby agrees to purchase, the Company Shares; and

(b) the Purchaser hereby agrees to issue to the Vendor, and the Vendor hereby agrees to subscribe for the issuance of, the Payment Shares.

**3.2. Consideration for Company Shares**

The aggregate consideration for the Company Shares is the Payment Shares.

**3.3. Purchase of Voting Share**

On Closing, the Vendor agrees to purchase and subscribe for, and the Purchaser agrees to issue, one Voting Share for the purchase price of One Dollar ($1.00).

**3.4. Amalgamation of LDCs**

Immediately after Closing, the Company and Erie Thames Powerlines will be amalgamated upon and subject to the terms and conditions of this Agreement, including an amalgamation agreement in the form set out in Schedule 1.3.3.

## 4. <u>CLOSING DATE FINANCIAL STATEMENTS</u>

**4.1. Preparation of Closing Date Financial Statements**

4.1.1. Initial Preparation

(a) Promptly after the Closing Date, each Party will, at the expense of the Merged LDC in respect of the Company's and Erie Thames Powerlines' financial statements and at the expense of the Purchaser in respect of the Purchaser's consolidated financial statements, prepare or cause to be prepared the Closing Date Financial Statements, which shall be prepared in accordance with IFRS, applied on a basis consistent with the preparation of the Financial Statements. The Closing Date Financial Statements shall make adequate provision for the Taxes which relate to any taxation year or part thereof ending or arising before the Closing Date or ending as a consequence of the Closing which are not yet due and payable and for which Tax Returns are not yet required to be filed, and all vacation pay, bonuses, commissions and other payments under the Employee Benefits and Pensions Plan, if any, payable to the Employees shall be properly reflected and accrued in the Closing Date Financial Statements. Each Party and their authorized representatives shall receive from the Merged LDC such reasonable cooperation, assistance and access to all relevant books, records and personnel as may be required for a timely and accurate review of the Closing Date Financial Statements.

(b) The Merged LDC and the Purchaser, as applicable, shall deliver drafts of the Closing Date Financial Statements to the Parties no later than the 120th day following the

Closing Date. The Merged LDC and the Purchaser shall provide each Party and their authorized representatives with such reasonable cooperation, assistance and access to all relevant books, records and personnel as may be required for a timely and accurate review of the Closing Date Financial Statements. If a Party does not give a notice of disagreement in accordance with Section 4.1.2, said Party shall be deemed to have accepted the drafts of the Closing Date Financial Statements, which shall be final and binding on the Parties for all purposes, including the purposes of this Agreement, immediately following the expiry date for the giving of such notice of disagreement.

4.1.2. Dispute Settlement

Each Party shall have thirty (30) days after its receipt of the draft Closing Date Financial Statements to review same. If a Party disagrees with any items in the draft Closing Date Financial Statements prepared pursuant to Section 4.1.1, said Party shall give notice to the other Party of such disagreement. Any notice of disagreement given by a Party shall set forth in detail the particulars of such disagreement. The Parties shall then use reasonable efforts to resolve such disagreement for a period of thirty (30) days following the giving of such notice. If the matter is not resolved by the end of such period, then such disagreement shall be submitted by the Parties to an accounting firm of recognized national standing in Canada, which is independent of the parties (the "Independent Accountant") as agreed by the Parties. The Independent Accountant shall, as promptly as practicable, make a determination in respect of the dispute concerning the Closing Date Financial Statements based on submissions of the Parties to the Independent Accountant. The decision of the Independent Accountant as to the Closing Date Financial Statements shall be final and binding upon the Parties for all purposes, including the purposes of the Agreement. The Parties shall each pay one-half of the fees and expenses of the Independent Accountant with respect to the resolution of the dispute.

**4.2. Officer's Certificates**

In the event that the Closing Date occurs after December 31, 2017, the officers of the Company and the Purchaser, in their capacities as officers of their respective companies and without personal liability, shall deliver a certificate of knowledge (the "Officer's Certificates") stating that, to the best of his or her knowledge (i) there have been no dividends paid to shareholders of their respective companies following the Closing Date Financial Statements, and (ii) there have been no changes, effects or circumstances that are materially adverse to the financial condition of their respective companies following the Closing Date Financial Statements.

**4.3. Retained Earnings**

4.3.1. Company

The Company's retained earnings on the Closing Date, as reflected in the Closing Date Financial Statements, shall not be less than those set out in the Financial Statements.

4.3.2. Purchaser

The Purchaser's retained earnings on the Closing Date, as reflected in the Purchaser's Closing Date Financial Statements, shall not be less than those set out in the Financial Statements.

## 5. VENDOR'S REPRESENTATIONS AND WARRANTIES

The Vendor hereby represents and warrants to the Purchaser as follows, and acknowledges that the Purchaser is relying on such representations and warranties in connection with the transactions herein contemplated:

### 5.1. Incorporation of the Vendor

The Vendor is a municipality duly incorporated and validly existing under the laws of the Province of Ontario. No proceedings or governmental action have been instituted or are pending that could reasonably be expected to have a material adverse effect on the ability of the Vendor to carry out the transactions contemplated hereunder. The Vendor has the necessary power, authority and capacity to own or lease and use its property and assets.

### 5.2. Due Authorization

The Vendor has all necessary Consents and Approvals, corporate power, authority and capacity to enter into this Agreement and to carry out its obligations under this Agreement, including, without limitation, the sale by the Vendor to the Purchaser of the Company Shares and the purchase of and subscription by the Vendor for the ERTH Shares as contemplated herein. The execution and delivery of this Agreement and the consummation of the transactions contemplated by this Agreement have been duly authorized by all necessary corporate action on the part of the Vendor.

### 5.3. Incorporation of the Company

The Company is duly incorporated, organized and subsisting under the laws of the Province of Ontario, the Company is a corporation established pursuant to section 142 of the Electricity Act, and no proceedings have been instituted or are pending for the dissolution of the Company.

### 5.4. Qualification to do Business

The Company has all necessary corporate power, authority and capacity to own its property and assets and to carry on its Business as currently conducted. To the Vendor's knowledge, the Company has made all necessary filings under all applicable Laws, except for such filings where the failure to file would not have a material adverse effect on the Company, and the Company does not conduct its Business in any jurisdiction other than the Province of Ontario.

## 5.5. Enforceability of Obligations

This Agreement constitutes a valid and binding obligation of the Vendor enforceable against the Vendor in accordance with its terms, subject, however, to (i) limitations with respect to enforcement imposed by law in connection with bankruptcy or similar proceedings and to the extent that equitable remedies such as specific performance and injunction are in the discretion of the court from which they are sought; and (ii) receipt of all Required Regulatory Approvals.

## 5.6. Right to Sell

The Vendor is the sole registered and beneficial owner of the Company Shares free and clear of all Encumbrances. The Vendor has the exclusive rights to dispose of the Company Shares as provided in this Agreement, subject to receipt of all Required Regulatory Approvals and Consents and Approvals, and such disposition will not violate, contravene, breach or offend against or result in any default under any indenture, mortgage, lease, agreement, obligation, instrument, charter or by-law provision, statute, regulation, order, judgment, decree, license, permit or law to which either the Vendor or the Company is bound or affected.

## 5.7. Shareholder Direction

The Company Shares are subject to a shareholder direction related to the Company, a true copy of which has been disclosed to the Purchaser.

## 5.8. Company Promissory Note

The Company Promissory Note represents the only indebtedness of the Company to the Vendor, except for any liabilities arising in the normal course of business. At Closing, the amount of the Company Promissory Note will be the amount set out in Schedule 1.1.13. The Vendor has not previously sold, conveyed, assigned or transferred the Company Promissory Note (or any part thereof). The Vendor has not taken any action to demand or accelerate repayment of the Company Promissory Note.

## 5.9. Bankruptcy

The Company has not committed an act of bankruptcy for which it has not been discharged, the Company is not insolvent, nor has the Company proposed a compromise or arrangement to its creditors generally, or had any petition for a receiving order in bankruptcy filed against it, or made a voluntary assignment in bankruptcy, or taken any proceeding with respect to a compromise or arrangement, or taken any proceeding to have itself declared bankrupt or wound-up, as applicable, or taken any proceeding to have a receiver appointed in respect of any part of its respective assets, or had any encumbrancer take possession of any of its respective property, or assets or had any executive or distress become enforceable or become levied upon any of its assets or property.

## 5.10. Tax Status

The Vendor and the Company are municipal corporations for the purposes of paragraph 149(1)(d.5) of the Income Tax Act.

## 5.11. Undisclosed Subsidiaries

To the Vendor's knowledge, the Company does not own, or have any interest in, any shares of any corporation, subsidiary or affiliate, as such terms are defined in the Business Corporations Act (Ontario), nor has the Company entered into any agreements of any nature to acquire any subsidiary or to acquire or lease any other business operations.

## 5.12. Capitalization of the Company

The authorized capital of the Company consists of an unlimited number of common shares of which One Hundred (100) common shares (and no more) are currently and shall be issued and outstanding at Closing. All of the Company Shares have been duly and validly issued and are outstanding as fully paid and non-assessable shares and all of the Company Shares are owned by the Vendor as the registered and beneficial owner thereof with good and marketable title thereto, free and clear of all Encumbrances. No options, warrants, or other rights to purchase shares or other securities of the Company, and no securities or obligations convertible into or exchangeable for shares or other securities of the Company, have been authorized or agreed to be issues or are outstanding.

## 5.13. Absence of Conflicting Agreements

To the Vendor's knowledge, neither the Vendor nor the Company is a party to, bound or affected by or subject to any indenture, mortgage, lease, agreement, obligation, instrument, charter or by-law provision, statute, regulation, order, judgment, decree, license, permit or Law which would be violated, contravened, or breached by, or under which default would occur as a result of, the execution and delivery of this Agreement or the performance by them of any of their obligations provided for under this Agreement.

## 5.14. Financial Statements

The Company's financial statements that have been disclosed to the Purchaser have been prepared in accordance with IFRS, applied on a basis consistent with those of preceding periods, and present fairly in all material aspects:

(a) all of the assets, liabilities (whether accrued, absolute, contingent or otherwise) and the financial position of the Company for the applicable periods; and

(b) the revenues, earnings and results of operations of the Company as at for the applicable periods.

## 5.15. Validly Declared Dividends

All dividends, which up to the Closing Date have been declared or paid by the Company, have been duly and validly declared and paid.

## 5.16. Absence of Undisclosed Liabilities

To the Vendor's knowledge, the Company has no liabilities (whether accrued, absolute, contingent or otherwise matured or unmatured) except liabilities incurred in the ordinary course or business and attributable to the period since the date of the Financial Statements, which are not, either individually or in the aggregate, materially adverse to the Business, or to the operations, affairs, prospects or condition (financial or otherwise) of the Company.

## 5.17. No Material Adverse Change

Since the date of the Financial Statements, to the Vendor's knowledge there has been no material adverse change in the Business or in the operations, affairs, prospects or condition (financial or otherwise) of the Company, including revocation of any of the Licenses and Permits or as a result of fire, explosion, accident, casualty, labour problem, flood, drought, riot, storm, act of God or otherwise, except for changes occurring in the ordinary course of business and which, either individually or in the aggregate, have not materially adversely affected and will not materially adversely affect the Business or the operations, affairs, prospects or condition (financial or otherwise) of the Company.

## 5.18. Title to Personal Property

To the Vendor's knowledge, the Company is the sole beneficial and (where its interests are registrable) the sole registered owner of all personal property shown or reflected on the Financial Statements, with good and marketable title, free and clear of all Encumbrances and claims other than such personal property of the Company as have been disposed of or acquired in the normal course of business since the date of the Financial Statements.

## 5.19. Tax Filings

To the Vendor's knowledge, the Company has prepared and filed with all appropriate Governmental Authorities, all Tax Returns, declarations, remittances, information returns, reports, payments in lieu of taxes and other documents of every nature required to be filed by or on behalf of the Company respectively, in respect of any Taxes for all fiscal periods and will continue to do so in respect of any fiscal period ending before the Closing Date. All such returns, declarations, remittances, information returns, reports, payments in lieu of taxes and other documents are correct and complete in all material respects, and no material fact has been omitted therefrom. No extension of time in which to file any such returns, declarations, remittances, information returns, reports or other documents is in effect. To the Vendor's knowledge, the all

Taxes shown on all such Tax Returns or on any assessments or reassessments in respect of any such returns have been paid in full.

**5.20. Taxes Paid**

To the Vendor's knowledge, the Company has paid in full all Taxes due and payable by it and has made adequate provision in its financial statements in accordance with IFRS for the payment of all Taxes in respect of all fiscal periods ending before the Closing Date.

**5.21. Reassessment of Taxes**

To the Vendor's knowledge, there are no reassessments of Taxes that have been issued and which remain unpaid or unresolved against the Company for all taxation years prior to and including the Closing Date. There is no proceeding, investigation, claim, re-assessment or audit now pending or, to the knowledge of the Vendor, threatened in writing in respect of any Tax owing by the Company. The Company has not executed or filed with any Governmental Authority any agreement or waiver extending the period for assessment, reassessment or collection of any Taxes.

**5.22. Tax Data**

The Vendor has provided to the Purchaser information, complete and accurate in all material respects which is within the Vendor's knowledge, relating to the Company in respect of its Tax Returns filed with the appropriate Governmental Authorities and relating to the adjusted cost bases of non-depreciable capital properties and un-depreciated capital cost of depreciable properties.

**5.23. Absence of Guarantees**

To the Vendor's knowledge, the Company has not given or agreed to give, or is a party to or bound by, any guarantee or indemnity in respect of any indebtedness, or other obligations, of any Person, or any other commitment by which the Company is, or is contingently, responsible for such indebtedness or other obligations.

**5.24. Business in Compliance with Laws**

To the knowledge of the Vendor, the operations, business, properties and assets of the Company has always and is now conducted, in all material respects, in compliance with all Laws, and the Vendor has not received any notice of alleged breach of any such Laws and there are no matters under discussion with any Governmental Authority relating to any orders, notices, remedial or corrective actions, or similar requirements where the matters covered by any such notice or any of the matters under discussion with any Governmental Authority could have a material adverse affect upon the Company.

### 5.25. Legal Proceedings

To the Vendor's knowledge, there is no Legal Proceeding outstanding, pending or threatened in writing against the Vendor or the Company, or the Business, Real Property or personal property and assets which, if determined adversely to the Vendor or the Company, would:

(a) materially and adversely affect the assets property, operations, business, future prospects or financial condition of the Company;

(b) enjoin, restrict or prohibit the transfer of all or any part of the Company Shares as contemplated by this Agreement; or

(c) prevent the Vendor or the Company from fulfilling all of its respective obligations set out in this Agreement or the Material Contracts to which it is a party,

and the Vendor has no knowledge of any existing ground on which any such Legal Proceeding might be commenced with any reasonable likelihood of success.

### 5.26. Environmental Matters

To the Vendor's knowledge:

(a) The Company, the operation of the Business and the assets owned or used by the Company have been and are in compliance with all Environmental Laws.

(b) The Company has not been charged with or convicted of any offence for non-compliance with Environmental Laws, or been fined or otherwise sentenced or settled any prosecution short of conviction, and there are no notices of judgment or commencement of proceedings of any nature and the Company has never been investigated relating to any breach or alleged breach of Environmental Laws.

(c) The Company is not, and there is no basis upon which the Company could become, responsible for any clean-up or corrective action under any Environmental Laws.

### 5.27. Intellectual Property

To the Vendor's knowledge, the conduct of the Business does not infringe upon the patents, service marks, trade marks, trade names, industrial designs, copyrights and other industrial property rights, domestic or foreign, of any other person, firm or corporation.

### 5.28. Machinery and Equipment

To the Vendor's knowledge, all machinery and equipment owned or used by the Company has been properly maintained and is in good working order for the purposes of ongoing operation in the conduct of the business of the Company, subject to ordinary wear and tear for machinery and equipment of comparable age occurring in the normal course.

**5.29. Licenses, Registrations, Etc.**

To the Vendor's knowledge, the Company possesses all Licenses and Permits, certificates of approval and quotas necessary or required in order for the Company to conduct its business as now conducted including any and all regulatory Licenses and Permits as required under all applicable Laws, including but not limited to, the OEB Act, the *National Energy Board Act* (Canada), the Electricity Act, the *Public Utilities Act* (Ontario), the *Municipal Franchises Act* (Ontario) and to own, lease or operate its property and assets, the absence of which would have a material adverse effect upon the Company. To the Vendor's knowledge, all the Licenses and Permits are in full force and effect, the Company is not in violation of any material term or provision or requirement of any such Licenses and Permits, and no Person has provided written notice to the Company of any threat to revoke, amend or impose any condition in respect of, or commenced proceedings to revoke, amend or impose conditions in respect of, any License or Permit.

**5.30. Transfer By-law and Real Property Interests**

To the Vendor's knowledge, the Company holds the beneficial and legal title to the Real Property interests set out in the municipal transfer by-law passed by the Vendor which effected the transfer of assets from the Vendor's public utilities commission to the Company, a copy of which has been disclosed to the Purchaser, free and clear of all Encumbrances. To the Vendor's knowledge, all such Real Property is in material compliance with all applicable Laws and shall not cease to comply with all applicable Laws by virtue only of the execution of this Agreement and the transfer of the Company Shares.

**5.31. Collective Agreement**

A copy of the the collective agreement applying to the Company, either directly or by operation of law, with any trade union or association which may qualify as a trade union and any memoranda of settlement and/or letters of understanding that may alter the terms and conditions of any such collective agreements have been disclosed to the Purchaser.

**5.32. Full Disclosure**

To the best of the Vendor's knowledge, the Vendor has not withheld from the Purchaser any facts relating to the Company which would be material to an intended purchaser thereof. The Vendor has no knowledge of any facts, subject to Section 1.6 herein, relating to the Company not herein disclosed, which might be reasonably expected to deter the Purchaser from completing the transaction herein contemplated.

## 5.33. Conduct of Business in Ordinary Course

Since the date of the Financial Statements, the Business of the Company has been carried on in the ordinary course consistent with past practice.

## 5.34. Employment Matters

(a) Except as disclosed to the Purchaser, there are no employment policies or plans, including policies or plans regarding incentive compensation, stock options, severance pay or other terms or conditions of employment or terms or conditions upon which Employees may be terminated, which are binding upon the Company.

(b) Except as disclosed to the Purchaser, there are no actual or threatened complaints or proceedings, statutory or otherwise, against the Company pursuant to, without limitation, the *Pay Equity Act*, the *Employment Standards Act*, the *Labour Relations Act*, the Human Rights Code, the *Workplace Safety and Insurance Act*, the *Occupational Health and Safety Act* or before any other tribunal, strikes, lock-outs, work stoppages or other union organizing activities, grievances, arbitration cases or similar labour related disputes or proceedings. Further, to the knowledge of the Vendor, the Company is not liable for any damages to any Employee or former Employee, nor does the Company have any obligation to reinstate any Employee or former Employee, whether unionized or non-unionized, resulting from the violation of any applicable employment or labour Law or employment agreement.

## 5.35. Pension and Benefit Plan

(a) Current copies of the Pension Plan and all Employee Benefits for the Company have been disclosed to the Vendor.

(b) The Pension Plan is the only pension plan in any form whatsoever applicable to the Company, registered or unregistered, under which the Employees accrue pension benefits.

(c) To the knowledge of the Vendor, the Employee Benefits are, and have been, established and administered in compliance with the terms of such Employee Benefits and all applicable Laws. All employer payments, contribution or premiums required to be remitted or paid in respect of each Employee Benefit have been duly remitted.

(d) To the knowledge of the Vendor, there is currently no investigation, examination, proceeding, action, suit or claim, other than claims for benefits made by Employees in the normal course under the Employee Benefits, pending or threatened involved any Employee Benefit.

### 5.36. Withholdings and Remittances

To the knowledge of the Vendor, the Company has withheld from each payment made to any of its present or former Employees, officers and directors, and to all persons who are non-residents of Canada for the purposes of the Income Tax Act all amounts required by law to be withheld, and furthermore, have remitted such withheld amounts within the prescribed periods to the appropriate Governmental Authority. To the knowledge of the Vendor, the Company has remitted all Canada Pension Plan contributions, employment insurance and workers' compensation premiums, employer health taxes and other Taxes payable by them in respect of their respective Employees and have remitted such amounts to the proper Governmental Authority within the time required under the applicable Law. To the knowledge of the Vendor, the Company has charged, collected and remitted on a timely basis all Taxes as required under any applicable Law on any sale, supply or delivery whatsoever, made by the Company, as the case may be.

### 5.37. Insurance

The Company maintains all insurance policies that are prudent and commercially reasonable in operating its Business and all such policies are in full force and effect and the Company is not in default whether as to payment of premiums or otherwise, under the terms of such policies.

### 5.38. Real Property

(a) The Company has good and marketable title to all of its Real Property. All such Real Property (including, without limitation, the improvements thereon) is in material compliance with all applicable Laws.

(b) To the knowledge of the Vendor, neither the whole nor any part of the Real Property of the Company is subject to any existing or pending expropriation, condemnation or other taking by any Governmental Authority or other Person that has the right to expropriate real property, and no such expropriation, condemnation or other taking has been threatened. To the knowledge of the Vendor, no public improvements with respect to the Real Property have been ordered to be made by any Governmental Authority that have not been completed, assessed and paid for prior to the date of this Agreement.

(c) There are no existing defaults by the Company or, to the knowledge of the Vendor, any other party under any Encumbrances, if any, relating to the Real Property.

(d) The Vendor or the Company has not received any written work order, deficiency notice, notice of violation or other similar communication from any Governmental Authority or board of insurance underwriters or otherwise which is outstanding, requiring that work or repairs in connection with its Real Property, or any part thereof, is necessary or required.

## 6. REPRESENTATIONS AND WARRANTIES OF THE PURCHASER

The Purchaser hereby represents and warrants to the Vendor as follows and acknowledges that the Vendor is relying on such representations and warranties in connection with the transactions herein contemplated:

### 6.1. Incorporation of the Purchaser

The Purchaser and its Subsidiaries are corporations incorporated and validly subsisting under the laws of the Province of Ontario, the Purchaser is a corporation established pursuant to section 142 of the Electricity Act, and no proceedings or governmental action have been instituted or are pending that could reasonably be expected to have a material adverse effect on the ability of the Purchaser to carry out the transactions contemplated hereunder. The Purchaser has the necessary power, authority and capacity to own or lease and use its property and assets.

### 6.2. Qualification to do Business

The Purchaser and its Subsidiaries have the necessary corporate power, authority and capacity to own or lease its property and assets and to carry on its Businesses, as now being conducted by them, and is qualified to carry on such Businesses under the laws of each jurisdiction in which the nature of such Businesses as carried on by it makes such qualification necessary.

### 6.3. Due Authorization

The Purchaser has all necessary Consents and Approvals, corporate power, authority and capacity to enter into this Agreement including, without limitation, to purchase the Company Shares from the Vendor, to issue the ERTH Shares to the Vendor as herein contemplated, and to perform its other obligations hereunder. The execution and delivery of this Agreement and the consummation of the transactions contemplated by this Agreement have been duly authorized by all necessary corporate action of the Purchaser.

### 6.4. Enforceability of Obligations

This Agreement constitutes a valid and binding obligation of the Purchaser enforceable against the Purchaser in accordance with its terms, subject, however, to (i) limitations with respect to enforcement imposed by law in connection with bankruptcy or similar proceedings and to the extent that equitable remedies such as specific performance and injunction are in the discretion of the court from which they are sought; and (ii) receipt of all Required Regulatory Approvals.

### 6.5. Right to Issue the ERTH Shares

The Purchaser has the exclusive rights to issue the ERTH Shares as provided in this Agreement, subject to receipt of all Required Regulatory Approvals and Consent and Approvals, and the issuance of the ERTH Shares will not violate, contravene, breach or offend against or result in any default under any indenture, mortgage, lease, agreement, obligation, instrument, charter or by-law provision, statute, regulation, order, judgment, decree, license, permit or law to which the Purchaser is bound or affected.

### 6.6. Shareholder Agreement

The ERTH Shares are subject to the Shareholder Agreement, a true copy of which has been disclosed to the Vendor and its representatives.

### 6.7. Bankruptcy

Neither the Purchaser nor its Subsidiaries has committed an act of bankruptcy for which it has not been discharged, neither the Purchaser nor its Subsidiaries are insolvent, nor has the Purchaser or its Subsidiaries proposed a compromise or arrangement to its creditors generally, or had any petition for a receiving order in bankruptcy filed against it, or made a voluntary assignment in bankruptcy, or taken any proceeding with respect to a compromise or arrangement, or taken any proceeding to have itself declared bankrupt or wound-up, as applicable, or taken any proceeding to have a receiver appointed in respect of any part of their respective assets, or had any encumbrancer take possession of any of their respective property, or assets or had any executive or distress become enforceable or become levied upon any of their assets or property.

### 6.8. Tax Status

The Purchaser is a municipal corporation for the purposes of paragraph 149(1)(d. 5) of the Income Tax Act.

### 6.9. Subsidiaries and Affiliates

Schedule 1.1.56 lists all of the Purchaser's subsidiaries and affiliates, as those terms are defined in the Business Corporations Act (Ontario).

### 6.10. Capitalization of the Purchaser

The authorized capital of the Purchaser consists of an unlimited number of Class A shares (the attributes of which are attached hereto as Schedule 1.1.65) and an unlimited number of Class B shares (the attributes of which are attached hereto as Schedule 1.1.48), of which the following (and no more) are issued and outstanding on the date of this Agreement:

| Name of Shareholder | No. of Class A Shares Held | No. of Class B Shares Held |
|---|---|---|
| Town of Ingersoll | 1 | 8,169,909 |
| Town of Aylmer | 1 | 4,070,120 |
| Municipality of Central Elgin | 1 | 1,936,611 |
| Township of Norwich | 1 | 1,834,116 |
| Municipality of West Perth | 1 | 1,693,000 |
| Township of Zorra | 1 | 1,465,495 |
| Township of East Zorra-Tavistock | 1 | 1,366,596 |
| Township of South-West Oxford | 1 | 461,226 |

All of the authorized and issued shares in the capital of the Purchaser have been duly and validly issued and are outstanding as fully paid and non-assessable shares.

**6.11. Absence of Conflicting Agreements**

The Purchaser is not a party to, bound or affected by or subject to any indenture, mortgage, lease, agreement, obligation, instrument, charter or by-law provision, statute, regulation, order, judgment, decree, license, permit or Law which would be violated, contravened, or breached by, or under which default would occur or an Encumbrance would be created as a result of, the execution and delivery of this Agreement or the performance by it of any of its obligations provided for under this Agreement.

**6.12. Full Disclosure**

The Purchaser has not withheld from the Vendor any facts relating to the Purchaser or its Subsidiaries which would be material to the Vendor. The Purchaser has no knowledge of any facts, nor are there any facts which should reasonably be known to the Purchaser relating to the Purchaser and its Subsidiaries, not herein disclosed or disclosed to the Vendor's Valuator, which might be reasonably expected to diminish the Purchaser's appreciation of the worth or profitability of the Purchaser or its Subsidiaries or which, if known by the Purchaser, might be reasonably expected to deter it from completing the transaction herein contemplated.

**6.13. Financial Statements**

The Purchaser's Financial Statements that have been disclosed to the Vendor have been prepared in accordance with IFRS applied on a basis consistent with those of preceding periods, and present fairly in all material aspects:

(a) all of the assets, liabilities (whether accrued, absolute, contingent or otherwise) and the financial position of the Purchaser for the applicable periods; and

(b) the revenues, earnings and results of operations of the Purchaser for the applicable periods.

**6.15. Validly Declared Dividends**

All dividends, which up to the Closing Date have been declared or paid by the Purchaser, have been duly and validly declared and paid.

**6.16. Absence of Undisclosed Liabilities**

Except as disclosed in or contemplated by this Agreement, the Purchaser and its Subsidiaries have no liabilities (whether accrued, absolute, contingent or otherwise matures or unmatured) except liabilities incurred in the ordinary course of business and attributable to the period since the date of the Financial Statements, which are not, either individually or in the aggregate, materially adverse to the Business, or to the operations, affairs, prospects or condition (financial or otherwise) of the Purchaser or its Subsidiaries.

**6.17. No Material Adverse Change**

Since the date of the Financial Statements, there has been no material adverse change in the Business, the level of retained earnings, or in the operations, affairs, prospects or condition (financial or otherwise) of the Purchaser or its Subsidiaries, including any such change arising as a result of a payment of dividends or return of capital to the shareholders of the Purchaser, any change in any applicable Law, revocation of any of the Licenses and Permits or as a result of fire, explosion, accident, casualty, labour problem, flood, drought, riot, storm, act of God or otherwise, except for changes occurring in the ordinary course of business and which, either individually or in the aggregate, have not materially adversely affected and will not materially adversely affect the Business or the operations, affairs, prospects or condition (financial or otherwise) of the Purchaser or its Subsidiaries.

**6.18. Conduct of Business in Ordinary Course**

Since the date of the Financial Statements, the Businesses of the Purchaser and its Subsidiaries have been carried on in the ordinary course consistent with past practice.

**6.19. Tax Filings**

The Purchaser and its Subsidiaries have prepared and filed with all appropriate Governmental Authorities, all Tax Returns, declarations, remittances, information returns, reports, payments in lieu of taxes and other documents of every nature required to be filed by or on behalf of the Purchaser and its Subsidiaries respectively, in respect of any Taxes for all fiscal periods and will continue to do so in respect of any fiscal period ending before the Closing Date. All such returns, declarations, remittances, information returns, reports, payments in lieu of taxes and other documents are correct and complete in all material respects, and no material fact has been omitted therefrom. No extension of time in which to file any such returns, declarations, remittances, information returns, reports or other documents is in effect. All Taxes shown on all such Tax Returns or on any assessments or reassessments in respect of any such returns have been paid in full.

**6.20. Taxes Paid**

The Purchaser and its Subsidiaries have paid in full all Taxes due and payable and have made adequate provision in its financial statements in accordance with IFRS for the payment of all Taxes in respect of all fiscal periods ending before the Closing Date.

**6.21. Reassessment of Taxes**

There are no reassessments of Taxes that have been issued and which remain outstanding or unresolved against the Purchaser or its Subsidiaries for all taxation years prior to and including the Closing Date. There is no proceeding, investigation, claim, re-assessment or audit now pending or, to the knowledge of the Purchaser, threatened in writing in respect of any Tax owing by the Purchaser or the Subsidiaries. Neither the Purchaser nor its Subsidiaries have executed or filed with any Governmental Authority any agreement or waiver extending the period for assessment, reassessment or collection of any Taxes.

**6.22. Tax Data**

The Purchaser has provided to the Vendor information, complete and accurate in all material respects, relating to the Purchaser and its Subsidiaries in respect of its Tax Returns filed with the appropriate Governmental Authorities and relating to the adjusted cost bases of non-depreciable capital properties and the undepreciated capital cost of depreciable properties.

**6.23. Business in Compliance with Laws**

The operations, business, properties and assets of the Purchaser and its Subsidiaries have always and are now conducted, in all material respects, in compliance with all Laws, and the Purchaser or its Subsidiaries have not received any notice of alleged breach of any such Laws and there are no matters under discussion with any Governmental Authority relating to any orders, notices, remedial or corrective actions, or similar requirements where the matters covered by any such notice or any of the matters under discussion with any Governmental Authority could have a material adverse affect upon the Purchaser or its Subsidiaries.

## 6.24. Legal Proceedings

There is no Legal Proceeding outstanding or, to the knowledge of the Purchaser, pending or threatened against or relating to the Purchaser or its Subsidiaries, or their businesses, Real Property or personal property and assets which, if determined adversely to the Purchaser or its Subsidiaries, would:

(a) materially and adversely affect the assets property, operations, business, future prospects or financial condition of the Purchaser or its Subsidiaries;

(b) enjoin, restrict or prohibit the issuance of all or any part of the ERTH Shares as contemplated by this Agreement; or

(c) prevent the Purchaser or its Subsidiaries from fulfilling all of its respective obligations set out in this Agreement or the Material Contracts to which they are a party,

and the Purchaser has no knowledge of any existing ground on which any such Legal Proceeding might be commenced with any reasonable likelihood of success.

## 6.25. Environmental Matters

(a) The Purchaser and the Subsidiaries, the operation of the Business and the assets owned or used by the Purchaser and the Subsidiaries have been and are in compliance with all Environmental Laws.

(b) The Purchaser and the Subsidiaries have not been charged with or convicted of any offence for non-compliance with Environmental Laws, or been fined or otherwise sentenced or settled any prosecution short of conviction, and there are no notices of judgment or commencement of proceedings of any nature and the Purchaser and the Subsidiaries have never been investigated relating to any breach or alleged breach of Environmental Laws

(c) None of the Purchaser or any of its Subsidiaries is, and there is no basis upon which the Purchaser or any Subsidiary could become, responsible for any clean-up or corrective action under any Environmental Laws.

## 6.26. Employment Matters

(a) Except as disclosed to the Vendor and its authorized representatives, there are no employment policies or plans, including policies or plans regarding incentive compensation, stock options, severance pay or other terms or conditions of employment or terms or conditions upon which Employees may be terminated, which are binding upon the Purchaser and its Subsidiaries.

(b) There are no actual or threatened complaints or proceedings, statutory or otherwise, against the Purchaser and its Subsidiaries pursuant to, without limitation, the *Pay Equity Act*, the *Employment Standards Act*, the *Labour Relations Act*, the Human Rights Code, the *Workplace Safety and Insurance Act*, the *Occupational Health and Safety Act* or before any other tribunal, strikes, lock-outs, work stoppages or other union organizing activities, grievances, arbitration cases or similar labour related disputes or proceedings. Further, to the knowledge of the Purchaser, the Purchaser and its Subsidiaries is not liable for any damages to any Employee or former Employee, nor does the Purchaser and its Subsidiaries have any obligation to reinstate any Employee or former Employee, whether unionized or non-unionized, resulting from the violation of any applicable employment or labour Law or employment agreement.

**6.27. Pension and Benefit Plan**

(a) Current copies of the Pension Plan and all Employee Benefit plans for the Purchaser and its Subsidiaries have been provided to or made available to the Vendor.

(b) The Pension Plan is the only pension plan in any form whatsoever applicable to the Purchaser and its Businesses, registered or unregistered, under which the Employees accrue pension benefits.

(c) The Employee Benefits are, and have been, established and administered in compliance with the terms of such Employee Benefit plans and all applicable Laws. All employer payments, contribution or premiums required to be remitted or paid in respect of each Employee Benefit have been duly remitted.

(d) There is currently no investigation, examination, proceeding, action, suit or claim, other than claims for benefits made by Employees in the normal course under the Employee Benefits, pending or threatened involved any Employee Benefit.

**6.28. Withholdings and Remittances**

The Purchaser and its Subsidiaries have withheld from each payment made to any of its present or former Employees, officers and directors, and to all persons who are non-residents of Canada for the purposes of the Income Tax Act all amounts required by law to be withheld, and furthermore, have remitted such withheld amounts within the prescribed periods to the appropriate Governmental Authority. The Purchaser and its Subsidiaries have remitted all Canada Pension Plan contributions, employment insurance and workers' compensation premiums, employer health taxes and other Taxes payable by them in respect of their respective Employees and have remitted such amounts to the proper Governmental Authority within the time required under the applicable Law. The Purchaser and its Subsidiaries have charged, collected and remitted on a timely basis all Taxes as required under any applicable Law on any sale, supply or delivery whatsoever, made by the Purchaser and its Subsidiaries, as the case may be.

### 6.29. Collective Agreement

Copies of the the collective agreements applying to the Purchaser and its Subsidiaries, either directly or by operation of law, with any trade union or association which may qualify as a trade union and any memoranda of settlement and/or letters of understanding that may alter the terms and conditions of any such collective agreements have been disclosed to the Vendor.

### 6.30. Intellectual Property

The conduct of the Purchaser's Businesses does not infringe upon the patents, service marks, trade marks, trade names, industrial designs, copyrights and other industrial property rights, domestic or foreign, of any other person, firm or corporation.

### 6.31. Insurance

The Purchaser and its Subsidiaries maintain all insurance policies that are prudent and commercially reasonable in operating its Businesses and all such policies are in full force and effect and the Purchaser or its Subsidiaries are not in default whether as to payment of premiums or otherwise, under the terms of such policies.

### 6.32. Licenses, Registrations, Etc.

The Purchaser and its Subsidiaries possess all Licenses and Permits, certificates of approval and quotas necessary or required in order for the Purchaser and its Subsidiaries to conduct their business as now conducted including any and all regulatory Licenses and Permits as required under all applicable Laws, including but not limited to, the OEB Act, the *National Energy Board Act* (Canada), the Electricity Act, the *Public Utilities Act* (Ontario), the *Municipal Franchises Act* (Ontario) and to own, lease or operate its property and assets, the absence of which would have a material adverse effect upon the Purchaser and its Subsidiaries. All the Licenses and Permits are in full force and effect, the Purchaser and its Subsidiaries are not in violation of any material term or provision or requirement of any such Licenses and Permits, and no Person has provided notice in any form whatsoever to the Purchaser or its Subsidiaries of any threat to revoke, amend or impose any condition in respect of, or commenced proceedings to revoke, amend or impose conditions in respect of, any License or Permit.

### 6.33. Real Property

(a) The Purchaser and its Subsidiaries have good and marketable title to all of its Real Property. All such Real Property (including, without limitation, the improvements thereon) is in material compliance with all applicable Laws.

(b) To the knowledge of the Purchaser, neither the whole nor any part of the Real Property of the Purchaser or its Subsidiaries is subject to any existing or pending expropriation, condemnation or other taking by any Governmental Authority or other Person that has the right to expropriate real property, and no such expropriation, condemnation or other taking has been threatened. To the knowledge of the Purchaser, no public improvements with respect to the Real Property have been ordered to be made by any Governmental Authority that have not been completed, assessed and paid for prior to the date of this Agreement.

(c) There are no existing defaults by the Purchaser or, to the knowledge of the Purchaser, any other party under any Encumbrances, if any, relating to the Real Property.

(d) The Purchaser has not received any written work order, deficiency notice, notice of violation or other similar communication from any Governmental Authority or board of insurance underwriters or otherwise which is outstanding, requiring that work or repairs in connection with its Real Property, or any part thereof, is necessary or required.

## 7. COVENANTS

### 7.1. Investigations and Availability of Records

Between the date hereof and the Closing Date, each Party shall permit the other and its representatives to make such investigations of the business, property, assets, and legal, financial and tax condition of such Party and its compliance with all Laws, Licenses and Permits and regulations as the other Party and its representatives deem necessary or desirable, acting reasonably; provided that such investigations shall be carried our without undue interference with the operations of any Party and the Parties shall use commercially reasonable efforts to co-operate in facilitating such investigations and shall furnish copies of all such documents and materials relating to such matters as may be reasonably required. Such investigations shall not, however, affect or mitigate the representations and warranties of the Parties contained in this Agreement or in any agreement, certificate, affidavit, statutory declaration or other document delivered or give pursuant to this Agreement, which representations and warranties shall continue in full force and effect.

### 7.2. Conduct of Business

(a) Between the date hereof and the Closing Date, the Parties shall cause its respective companies to:

i. carry on its respective Businesses in the ordinary course (except as may be otherwise required or contemplated by the provisions of this Agreement, including this Section);

ii. to preserve the business and the goodwill of suppliers, customers and others having relations with the company, and to maintain in full force and effect all intellectual and industrial property rights owned by and all licence agreements or arrangements with respect to intellectual and industrial property rights held by the company; and

iii. continue in full force and effect the insurance coverage currently in place and to cause the company to give all notices and to present all claims under all insurance policies in a due and timely fashion and to promptly advise the other Party in writing of any such claims.

(b) Between the date hereof and the Closing Date, the Vendor and the Purchaser (in the event that the Purchaser is authorized by the Vendor or the Company take any actions identified in Subsections 7.2(b)(i)-(vii) below) shall ensure that the Company does not (except as may be otherwise required or contemplated by the provisions of this Agreement, including this Section), without the prior written consent of the Purchaser:

i. take any step to dissolve, wind-up or otherwise affect its continuing corporate existence or amalgamate or merge with any Person or amend its articles of incorporation or by-laws;

ii. make any loan to or investment in any Person;

iii. become a party to or bound by or subject to any new debt instrument or increase the amount of, amend or concur in the amendment of or prepay or vary the terms of any indebtedness or other obligation under any existing debt instrument;

iv. other than the annual dividend for 2017, declare or pay any dividend or other distribution (whether out of capital or surplus or otherwise) on any of its outstanding securities, if such distribution results in a violation of Section 5.16, or redeem, purchase or otherwise acquire any of its outstanding securities other than as may be contemplated by this Agreement;

v. cancel, waive or vary the terms of any debt owing to or any claim or right of the Company;

vi. issue any shares or other securities or make any change in the number or class of or rights attached to any issued or unissued shares of its capital stock or grant, issue or make any option, warrant, subscription, convertible security or other right or commitment to purchase or acquire any shares of its capital stock or other securities; or

vii. create or permit the creation of any new Encumbrance on any of its property or assets (except for any lien for unpaid Taxes not yet due) or amend or concur in the amendment of any such existing Encumbrance.

or agree or become bound to do any of the foregoing.

(c) Between the date hereof and the Closing Date, the Vendor shall cause the Company, and the Purchaser shall cause the Purchaser and its Subsidiaries:

i. to prepare and file, if applicable, in a timely manner all Tax Returns required to be filed by it and pay all Taxes required under any applicable Law to be paid by it and to ensure that all such Tax Returns are true, correct and complete in all material respects and that such Tax Returns and all materials accompanying such Tax Returns reflect complete and accurate disclosure;

ii. to pay within the time prescribed by any applicable Law any required installments of Taxes, if applicable;

iii. to withhold from each payment made by it the amount of all Taxes and other deductions required under any applicable Law to be withheld therefrom and to pay all such amounts withheld to the relevant taxing or other authority within the time prescribed under any applicable Law; and

iv. not to enter into any arrangements to provide for an extension of time with respect to any assessment or reassessment of Tax, the filing of any Tax Return or the payment of any Tax by it without the prior written consent of the Purchaser.

### 7.3. Submission of OEB Applications

The Purchaser shall be responsible for preparing and submitting applications to the OEB to obtain all of the Required Regulatory Approvals. Notwithstanding the foregoing, the Vendor and the Company shall cooperate with the Purchaser and take all necessary steps required to assist the Purchaser in preparing and submitting the above applications. All costs associated with the preparation and submission of the OEB applications will be paid by the Merged LDC after the closing the Amalgamation contemplated herein. In the event that the Amalgamation is declined by the OEB, these costs will be paid by the Purchaser.

## 8. PURCHASER'S CONDITIONS OF CLOSING

### 8.1. Conditions for the Benefit of the Purchaser

The transactions herein contemplated, including the transfer of the Company Shares and the issuance of the ERTH Shares in accordance with the terms of this Agreement are subject to the following conditions, each of which is hereby declared to be for the exclusive benefit of the Purchaser. Each of such conditions is to be fulfilled or performed at or prior to the

Closing. The Vendor covenants and agrees to use its best efforts to cause each of such conditions to be fulfilled and/or performed at or prior to the Closing.

8.1.1. Representations and Warranties

The representations and warranties of the Vendor set forth in Article 5 shall be true and correct at the Closing with the same force and effect as if made at and as of such time.

8.1.2. Performance of Covenants

The Vendor shall have performed or complied with all of the terms, covenants and conditions of this Agreement to be performed or complied with by the Vendor at or prior to the Closing, including, without limitation, the covenants set forth in Article 7.

8.1.3. Closing Certificates

The Purchaser shall be furnished with such Closing Documents of directors or an officer of the Vendor or Company, as applicable, as may be reasonably necessary in order to establish that the terms, covenants and conditions contained in this Agreement have been performed or complied with by the Vendor and the Company, as the case may be, including those set out in Articles 10 and 11, at or prior to the Closing have been performed and complied with and that the representations and warranties of the Vendor herein given are true and correct at the Closing.

8.1.4. Licenses and Permits

The Company shall have received, to the Purchaser's satisfaction, acting reasonably, all Licenses and Permits required to carry on the Business and shall have given such notices and made such filings as are required to be given or made under the Electricity Act, the OEB Act, the *Environmental Protection Act* (Ontario), the *Ontario Water Resources Act* (Ontario), the *Operation Engineers Act* (Ontario) and other applicable Laws to notify relevant authorities of the change of control of the Company contemplated hereby.

8.1.5. Consents and Approvals

The Vendor and the Company shall have received, to the Purchaser's satisfaction, acting reasonably, all of the Consents and Approvals and the Vendor shall have delivered to the Purchaser reasonable evidence thereof.

8.1.6. Required Regulatory Approvals

The Required Regulatory Approvals shall have been received on terms and conditions satisfactory to the Purchaser, acting reasonably.

8.1.7. Satisfactory Closing Arrangements

The closing arrangements described in Section 10 below have been performed in manner satisfactory to the Purchaser, acting reasonably.

8.1.8. Satisfactory Completion of Due Diligence

The Purchaser shall have conducted due diligence necessary to satisfy itself, in its sole and unfettered discretion, with respect to the condition and operation of the Company.

8.1.9. Legal Matters

The form and legality of all matters incidental to the transactions contemplated in this Agreement shall be subject to the approval of the Purchaser, acting reasonably.

**8.2. Non-Fulfillment of Conditions etc. for the Benefit of the Purchaser**

In the event that any condition, obligation, covenant or agreement of the Vendor to be fulfilled or performed hereunder at or prior to the Closing, including, without limitation, the conditions set forth in this Article 8, shall not be fulfilled and/or performed at or prior to the Closing, the Purchaser may rescind this Agreement by notice to the Vendor and in such event the Purchaser shall be released from all obligations hereunder and, unless the Purchaser can show that the one or more conditions, obligations, covenants or agreements for the non-fulfillment or non-performance of which the Purchaser has rescinded this Agreement is or are reasonably capable of being fulfilled or performed or caused to be fulfilled or performed by the Vendor, then the Vendor shall also be released from all obligations hereunder; provided, however, that any of the said conditions, obligations, covenants, or agreements may be waived in whole or in part by the Purchaser without prejudice to the Purchaser's right of rescission in the event of the non-fulfillment and/or non-performance of any other condition, obligation, covenant or agreement, any such waiver to be binding on the Purchaser only if the same is in writing.

## 9. VENDOR'S CONDITIONS OF CLOSING

**9.1. Conditions for the Benefit of the Vendor**

The transactions herein contemplated, including the transfer of the Company Shares and the issuance of and subscription for the ERTH Shares in accordance with the terms of this Agreement are subject to the following conditions, each of which is hereby declared to be for the exclusive benefit of the Vendor. Each of such conditions is to be fulfilled or performed at or prior to the Closing. The Purchaser covenants and agrees to use its best efforts to cause each of such conditions to be fulfilled and/or performed at or prior to the Closing.

9.1.1. Representations and Warranties

The representations and warranties of the Purchaser set forth in Article 6 shall be true and correct at the Closing with the same force and effect as if made at and as of such time.

9.1.2. Performance of Covenants

The Purchaser shall have performed or complied with all of the terms, covenants and conditions of this Agreement to be performed or complied with by the Purchaser at or prior to the Closing, including, without limitation, the covenants set forth in Article 7.

9.1.3. Closing Certificates

The Vendor shall be furnished with such Closing Documents of directors or an officer of the Purchaser or Erie Thames Powerlines, as applicable, as may be reasonably necessary in order to establish that the terms, covenants and conditions contained in this Agreement have been performed or complied with by the Purchaser and its Subsidiaries, as the case may be, including those set out in Articles 10 and 11, at or prior to the Closing have been performed and complied with and that the representations and warranties of the Purchaser herein given are true and correct at the Closing.

9.1.4. Consents and Approvals

The Purchaser shall have received, to the satisfaction of the Vendor's Solicitors, acting reasonably, all of the Consents and Approvals, and the Purchaser shall have delivered to the Vendor reasonable evidence thereof.

9.1.5. Required Regulatory Approvals

The Required Regulatory Approvals shall have been received on terms and conditions satisfactory to the Vendor, acting reasonably.

9.1.6. Satisfactory Closing Arrangements

The closing arrangements described in Section 10 below have been performed in manner satisfactory to the Vendor's Solicitors, acting reasonably.

9.1.7. Satisfactory Completion of Due Diligence

The Vendor shall have conducted due diligence necessary to satisfy itself, in its sole and unfettered discretion, with respect to the condition and operation of the Purchaser.

9.1.8. Legal Matters

The form and legality of all matters incidental to the transactions contemplated in this Agreement shall be subject to the approval of the Vendor's Solicitors, acting reasonably.

**9.2. Non-Fulfillment of Conditions etc. for the Benefit of Vendor**

In the event that any conditions, obligation, covenant or agreement of the Purchaser to be fulfilled or performed hereunder at or prior to the Closing, including, without limitation, the conditions set forth in this Article 9, shall not be fulfilled and/or performed at or prior to the Closing, the Vendor may rescind this Agreement by notice to the Purchaser and in such event the Vendor shall be released from all obligations hereunder and, unless the Vendor can show that the one or more conditions, obligations, covenants or agreements for the non-fulfillment or non-performance of which the Vendor have rescinded this Agreement is or are reasonably capable of being fulfilled or performed or caused to be fulfilled or performed by the Purchaser, then the Purchaser shall also be released from all obligations hereunder; provided, however, that any of the said conditions, obligations, covenants or agreements may be waived in whole or in part by the Vendor without prejudice to the Vendor's right of rescission in the event of non-fulfillment and/or non-performance of any other condition, obligation, covenant or agreement, any such waiver to be binding on the Vendor's only if the same is in writing.

## 10. <u>CLOSING ARRANGEMENTS</u>

**10.1. Time and Place of Closing**

The Closing shall take place electronically on the Closing Date at 12:01 a.m. or at such other time and places as may be agreed upon between the Parties.

**10.2. Closing Arrangement**

At the Closing and subject to the fulfillment of all the terms and conditions set forth in this Agreement which have not been waived in writing by the Parties, respectively:

(a) Transfer of the Company Shares

The Vendor shall:

(i) deliver to the Purchaser, the certificate representing the Company Shares duly endorsed in blank for transfer or accompanied by a stock transfer power; and

(ii) take, and shall cause the Company to take, all necessary steps and proceedings as approved by the Purchaser, acting reasonably, to permit the Company Shares to be duly and validly transferred to the Purchaser, to have such transfers duly and validly transferred to the Purchaser, to have such transfers duly and validly recorded on the books of the Company so that the Purchaser is entered on the books of the Company as the holder of the Company Shares, and to issue one or more share certificates to the Purchaser representing the Company Shares.

(b) Transfer of the Payment Shares

The Purchaser shall:

(i) deliver to the Vendor, the certificates representing the Payment Shares duly and regularly issued to the Vendor from the treasury of the Purchaser; and

(ii) take, and shall cause the Purchaser to take, all necessary steps and proceedings as approved by the Vendor's Solicitors, acting reasonably, to permit the Payment Shares to be duly and validly issued to the Vendor, to have such shares duly and validly issued to the Vendor, to have the issuance of such shares duly and validly recorded on the books of the Purchaser so that the Vendor is entered on the books of the Purchaser as the holder of the Payment Shares, and to issue the relevant share certificates to the Vendor representing the Payment Shares.

(c) Transfer of the Voting Share

The Vendor shall:

(i) make the payment to the Purchaser as provided for in Section 3.3;

(ii) execute an Accession Agreement in the form attached as schedule 1 to the Shareholders Agreement which is required to bind the Vendor to the Shareholder Agreement and the terms and conditions therein; and

(iii) notify the Purchaser of its director appointee pursuant to the terms of the Shareholder Agreement.

The Purchaser shall:

(i) deliver to the Vendor, the certificate representing the Voting Share duly and regularly issued to the Vendor from the treasury of the Purchaser; and

(ii) take, and shall cause the Purchaser to take, all necessary steps and proceedings as approved by the Vendor's Solicitors, acting reasonably, to permit the Voting Share to be duly and validly issued to the Vendor, to have such share duly and validly issued to the Vendor, to have the issuance of such share duly and validly recorded on the books of the Purchaser so that the Vendor is entered on the books of the Purchaser as the holder of the Voting Share, and to issue the relevant share certificates to the Vendor representing the Voting Share.

## 10.3. Delivery of Closing Documentation

The Parties shall deliver all documentation and other evidence reasonably requested by the other Party in order to establish the due authorization and consummation of the transactions contemplated in this Agreement, including the taking of all corporate proceedings by the boards of directors and shareholders of the Vendor, the Company and the Purchaser, as the case may be, required to effectively carry out their respective obligations pursuant to this Agreement.

## 10.4. Delivery of Books and Records

The Vendor shall deliver or cause the Company to deliver to the Purchaser all the Company's books and records including, but not limited to, minute and record books, corporate records and documents, corporate seals, books of account, accounting records, past financial statements, Tax Returns, share certificate books and share records, title documents and surveys, Licenses and Permits, and registrations held by the Company, debt instruments, guarantees, Encumbrances, agreements, contracts and commitments to which the Company is a party to or bound by or subject to, lists of suppliers and customers and all other documents, files, records and other data, financial or otherwise, of the Company which may be in the possession of the Company or of the Vendor.

## 10.5. Releases

The Vendor shall cause to be executed and delivered to the Purchaser a release by the Vendor, and by each director and officer of the Company and such other Persons as the Purchaser may specify, each such release to be in a form satisfactory to the Purchaser. The Purchaser shall cause to be executed and delivered to the Vendor a release by the Purchaser, and by such other Persons as the Vendor may specify, each such release to be in a form satisfactory to the Vendor's Solicitor.

## 10.6. Resignations of Directors and Officers

The Vendor shall cause such directors and officers of the Company as the Purchaser may specify to resign in favour of nominees of the Purchaser, such resignations to be effective at the Closing unless a later time is specified by the Purchaser.

# 11. POST-CLOSING COVENANTS

## 11.1. Access to Books and Records

For a period of five years following the date hereof or, in the case of tax matters referred to in Section 11.2 for the period commencing as at the date hereof and ending on the date on which the last applicable limitation period under any applicable law expires which is relevant in determining any liability under this Agreement with respect to such particular tax matter, the Purchaser shall, during reasonable business hours and upon at least 48 hours prior notice from the Vendor, provide the Vendor or their representatives with access to any and all of the books and records of the Company existing as of the date hereof, or which affect any calculations, obligations or rights of the Vendor under this Agreement. The Purchaser shall not be responsible or liable to the Vendor for or as a result of any accidental loss or destruction of or damage to the books and records whether caused by the Purchaser or otherwise, except in the case of gross negligence or willful misconduct of the Purchaser or the Company or those persons for whom they are responsible at law; provided that the Purchaser and the Company shall take all usual steps to protect such books and records as a prudent business would take in the circumstances.

**11.2. Final Tax Return**

(a) The Vendor shall, at the Vendor's expense, prepare or cause to be prepared the Tax Returns of the Company in respect of Taxes for the periods ending as a consequence of the Closing Date (collectively, the "Final Tax Returns"). The Purchaser shall cause the Company to issue and file all such forms and notices as may be required in connection with such Final Tax Returns. To assist the Vendor for these purposes, the Purchaser shall provide to the Vendor and their authorized representatives such reasonable cooperation, assistance and access to relevant books, records and personnel as my be required for timely and accurate preparation of the Final Tax Returns. Within 120 days after the Closing Date, the Vendor shall provide such returns to the Purchaser for its review, together with any supporting documentation as may be reasonably required by the Purchaser in respect of such review. The Purchaser shall have 30 days thereafter to review the Final Tax Returns. If the Purchaser fails to object to any item or matter in the Final Tax Returns within such 30 days period then the Final Tax Return will be considered determinative of the Tax liability of the Company in respect of the periods covered by the Final Tax Returns. The Purchaser may object within such 30 day period by giving notice to the Vendor setting out in reasonable detail the nature of such objection. The Parties agree to use their best efforts to resolve the dispute within 15 days from the date that the Purchaser gives such notice to the Vendor. If the Purchaser and the Vendor cannot resolve the dispute within such 15 day period, the dispute shall be resolved in favour of the Purchaser for the purpose of enabling the Purchaser to file such Final Tax Returns in a timely manner (as set forth in the last sentence of this Section 11.2(a)), provided that the Final Tax Returns are prepared in accordance with all applicable law, and provided further that, the Vendor may refer the dispute to the Independent Accountant. The Independent Accountant shall, as promptly as practicable (but in any event within 45 days following its appointment), make a determination in respect of the dispute concerning the Final Tax Returns based on submissions of the Purchaser and the Vendor to the Independent Accountant. The decision of the Independent Accountant as to the dispute concerning the Final Tax Returns shall be final and binding upon the Parties. The Purchaser and the Vendor shall each pay one-half of the fees and expenses of the Independent Accountant with respect to the resolution of the dispute. Thereafter, the Purchaser shall, in a timely manner, cause such returns to be executed and filed with the appropriate Governmental Authority and if required, file a Notice of Objection if the Final Tax Return has already been assessed. The Purchaser shall be responsible for any solicitors fees arising from filing a Notice of Objection.

(b) The Vendor shall remit to the Governmental Authority all amounts shown as being a Taxes balance due on the Final Tax Return. For greater certainty, the Vendor shall be responsible for all Taxes accrued by the Company up to and including the Closing Date.

(c) In the event of a reassessment by a Governmental Authority of the Final Tax Returns in respect of Taxes for the periods ending on and before the Closing Date, the Vendor has the right at its sole expense to dispute and contest in the name of the Company, such reassessment. The payment of any reassessment by the Vendor, in respect of Taxes pursuant to this Agreement on behalf of the Company, shall be repaid to the Vendor, if repaid by the taxing authority. The Purchaser shall provide reasonable cooperation with the Vendor and their counsel in all proceedings with respect to any such reassessment.

**11.3. Covenants Relating to Title and Tax**

The Vendor covenants and agrees that:

(a) If, at any time, any person, other than the Purchaser makes a claim that as of or before the Closing Date: (i) it owned, or had an agreement or option to purchaser, any of the Company Shares, or (ii) the Company Shares or any portion of the Company Shares were owned by it and not by the Vendor, then the Vendor shall take all steps and do all actions necessary to eliminate such claim such that the intent and object of this Agreement remains fulfilled.

(b) If, at any time, any Governmental Authority makes a Claim for payment of a Tax liability from the Company owing or accruing up to and including the Closing Date which was not reflected in the Closing Date Financial Statements or the Final Tax Returns for any reason, including a misrepresentation made or fraud committed in filing a Tax Return, then the Vendor shall take all steps and do all actions necessary to eliminate such claim, including, if required, the payment of the Tax liability claimed by the Governmental Authority as described above and any and all fines, penalties and interest associated therewith.

**11.4. Co-operation**

Following the Closing Date, the Parties shall co-operate and provide all reasonable assistance as may be reasonably requested by the Purchaser in order to enable a Party to file any documentation relating to the transaction contemplated herein as may be required by any Governmental Authority.

## 11.5. Employees

The Purchaser acknowledges that the obligations of the Company to its Employees will not be affected in any way by this Agreement, or by the Closing, and without limiting the generality of the foregoing, the Company shall continue to employ the eight (8) existing Company employees after the Closing on their existing or better terms of employment for a minimum of five (5) years including but not limited to, salary, wages, benefits and location of employment within the Town of Goderich. The Purchaser further acknowledges that the Company will be responsible for any liability or consequences in the event that the Company terminates any Employees or changes the terms of employment for such Employees and, subject to the Vendor's negligence or willful misconduct related to the treatment of the Employees before Closing, the Company will indemnify the Vendor and hold it harmless from such liability or consequences.

## 11.6. Lease Agreement

Immediately following Closing, the Purchaser shall cause the Merged LDC to enter into ten (10) year lease, in the form attached hereto as Schedule 11.6 (the "Lease") to occupy 240 Huckins Street, Goderich, Ontario (the "Goderich Building") where the Merged LDC will maintain its Highway 8 operations centre and headquarters servicing Goderich, Mitchell, Clinton and Dublin. The Parties agree that the lease payments payable by the Merged LDC under the Lease shall be the greater of (i) the lease amount currently paid by the Company for the Goderich Building (i.e. $81,672.48 per annum) or (ii) a lease rate established following a review of market value for a comparable location (which shall be undertaken on a regular basis following the closing of the transactions contemplated herein. The Purchaser will also explore new opportunities to move additional competitive businesses to the Goderich Building, including a traffic and street lighting division servicing Huron County and neighbouring communities, following the closing of the transaction contemplated herein.

## 11.7. Water Billing Transition and Services Agreement

After the Closing Date, the Purchaser shall provide and the Vendor will continue to receive water and sewer billing services at the historical rate of approximately $42,500 per annum. These rates shall be increased over a three (3) year period to reflect market rates comparable to the fees charged to the Purchaser's municipal shareholders for these services. On Closing, the Vendor and the Purchaser will enter into a water billing service agreement in the form attached hereto as Schedule 11.7, which reflects the terms described in this section.

## 11.8. Street and Traffic Light Service Agreement

On Closing, the Vendor and the Purchaser and/or the Merged Entity will enter into a traffic and traffic light maintenance agreement in the form attached hereto as Schedule 11.8.

### 11.9. Rate Mitigation Strategy

The proposed transaction will not result in increased electricity distribution rates for customers of the Company or Erie Thames Powerlines. The distribution rates payable by the customers of the Company or Erie Thames Powerlines on the Closing Date will not be rebased for a minimum period of five (5) years following the proposed transaction

### 11.10. Collective Agreements

The Parties acknowledge that certain employees of the Company and Erie Thames Powerlines are represented by two separate unions. Following the Closing of the proposed transaction, the Merged LDC will continue to recognize and operate under the two existing collective agreements. In the event that the unions enter into discussions about a single union for the Merged LDC, the Parties agree that the Merged LDC will remain neutral in these negotiations and only participate if absolutely necessary.

## 12. INDEMNITY AND SET-OFF

### 12.1. Non-Merger

The representations, warranties, covenants and other obligations contained in this agreement and in any Closing Document shall not merge on the Closing, and notwithstanding the Closing or any investigation made by any Party with respect hereto, shall continue in full force and effect.

### 12.2. Exclusive Remedy

All claims by any Party after Closing in respect of the representations and warranties contained in this Agreement or in any Closing Document shall be subject to the conditions and limitations set forth in this Article 12 and the rights of the set-off and indemnity in this Article 12 shall be the sole and exclusive remedy of any Party in respect of such claims.

### 12.3. Indemnification by the Vendor

12.3.1. Subject to the limitations in Section 12.5 and 12.6, the Vendor shall indemnify, defend and save harmless the Purchaser and its successors and assigns from and against any and all Loss suffered or incurred by them, as a direct or indirect result of, or arising in connection with or related in any manner whatever to:

(a) any inaccuracy of or any breach by the Vendor of, any representation or warranty of the Vendor contained in this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement (except that the Vendor shall not be required to indemnify or save harmless the Purchaser in respect of any inaccuracy or breach of any representation or warranty unless the Purchaser shall have provided notice to the Vendors in accordance with Section 12.7 on or prior to the expiration of the applicable time period related to that representation and warranty set out in Section 12.5);

(b) any breach or non-performance by the Vendor of any covenant or other obligation to be performed by it that is contained in this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement;

(c) any failure of the Vendor to transfer good and valid title to the Company Shares to the Purchaser, free and clear of all Encumbrances;

(d) all debts or liabilities, contingent or otherwise (including liabilities for Taxes) existing at the Closing Date, required to be but not disclosed in the Closing Date Financial Statements;

(e) all contingent liabilities (including all costs, payments and charges whatsoever relative to any litigation which the Company becomes obligated to pay), existing at the Closing Date, to the extent required to be but not disclosed in the Closing Date Financial Statements; and

(f) subject to Section 11.2, any assessment or re-assessment by any Governmental Authority in respect of any Tax or Taxes (including any Taxes owing pursuant to the Final Tax Returns) owing by the Company that relate to any period or periods ending on or before the Closing Date.

12.3.2. The provisions of Sections 12.6 and 12.7 shall not apply in respect of any inaccuracy or breach of a representation or warranty involving fraud or fraudulent misrepresentation.

**12.4. Indemnification by the Purchaser**

12.4.1. Subject to the limitations in Sections 12.6 and 12.7, the Purchaser shall indemnify, defend and save harmless the Vendor and its successors and assigns from and against any and all Loss suffered or incurred by them, as a direct or indirect results of, or arising in connection with or related in any manner related to:

(a) any inaccuracy of or any breach by either of the Purchaser and its Subsidiaries, as applicable, of any representation or warranty of the Purchaser contained in this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement (except that the Purchaser shall not be required to indemnify or save harmless the Vendor in respect of any inaccuracy or breach of any representation or warranty unless the Vendor shall have provided notice to the Purchaser in accordance with Section 12.7 on or prior to the expiration of the applicable time period related to that representation and warranty set out in Section 12.5); and

(b) any breach or non-performance by either of the Purchaser and its Subsidiaries, as applicable, of any covenant or other obligation to be performed by it that is contained in this Agreement or in any contract, agreement, instrument, certificate or other document delivered pursuant to this Agreement; and

(c) any assessment or re-assessment by any Governmental Authority in respect of any Tax or Taxes owing by the Purchaser or its Subsidiaries that relate to any period or periods ending on or before the Closing Date, subject to section 12.5.

12.4.2. The provisions of Sections 12.5 and 12.6 shall not apply in respect of any inaccuracy or breach of a representation or warranty involving fraud or fraudulent misrepresentation.

**12.5. Time Limitations**

(a) Subject to Section 12.5(c), the Vendor shall have no liability to the Purchaser for any Loss arising from any Claim described in Section 12.3 unless the Purchaser gives notice to the Vendor specifying in reasonable detail the factual basis of the Claim on or before the second anniversary of the Closing Date.

(b) Subject to Section 12.5(c), the Purchaser shall have no liability to the Vendor for any Loss arising from any Claim described in Section 12.4 unless the Vendor gives notice to the Purchaser specifying in reasonable detail the factual basis of the Claim on or before the second anniversary of the Closing Date.

(c) Despite the provisions of Sections 12.5(a) and 12.5(b), notice with respect to Claims relating to (i) environmental issues may be given on or before the tenth anniversary of the Closing Date, (ii) title of the Vendor to the Company Shares and title of the Company to its property and assets may be given at any time after Closing, (iii) Tax matters may be given at any time after Closing and prior to the 60$^{th}$ day following the last to expire of any time within which an assessment, reassessment or similar document may be issued under any applicable Law; and (iv) Transfer Tax may be given at any time after Closing.

**12.6. Limitations on Amount**

Notwithstanding any other provision of this Article 12:

(a) no Claim or Claims may be asserted by the Purchaser under Section 12.3 unless the aggregate amount of the Losses of the Purchaser in respect of such Claim or Claims is at least $10,000, in which event the amount of all such Losses, including such $10,000 amount, may be asserted; and

(b) no Claim or Claims may be asserted by the Vendor under Section 12.4 unless the aggregate amount of the Losses of the Vendor in respect of such Claim or Claims is at least $10,000, in which event the amount of all such Losses, including such $10,000 amount, maybe asserted.

### 12.7. Notice of Third Party Claim

If an Indemnitee receives notice of the commencement or assertion of any Third Party Claim, the Indemnitee shall give the Indemnitor reasonably prompt notice thereof, but in any event no later than 30 days after receipt of such notice of such Third Party Claim. Such notice to the Indemnitor shall describe the Third Party Claim in reasonable detail and shall indicate, if reasonably practicable, the estimated amount of the Loss that has been or may be sustained by the Indemnitee.

### 12.8. Defence of Third Party Claims

The Indemnitor may participate in or assume the defence of any Third Party Claim by giving notice to that effect to the Indemnitee not later than 30 days after receiving notice of that Third Party Claim (the "Notice Period"). The Indemnitor's right to do so shall be subject to the rights of any insurer or other party who has potential liability in respect of that Third Party Claim. The Indemnitor shall pay all of its own expenses of participating in or assuming such defence. The Indemnitee shall co-operate in good faith and in defence of each Third Party Claim, even if the defence has been assumed by the Indemnitor and may participate in such defence assisted by counsel of its own choice at its own defence. If an Indemnitee has not received notice within the Notice Period that the Indemnitor has elected to assumed the defence of such Third Party Claim, the Indemnitee may, at its option, elect to settle or compromise the Third Party Claim or assume such defence, assisted by counsel of its own choosing and the Indemnitor shall be liable for all reasonable costs and expenses paid or incurred in connection therewith any Loss suffered or incurred by the Indemnitee with respect to such Third Party Claim. If the Indemnitor elects to assume the defence of a Third Party Claim under this Section 12.8, the Indemnitor shall not have the right thereafter to contest its liability for such claim.

### 12.9. Assistance for Third Party Claims

The Indemnitor and the Indemnitee will use all reasonable efforts to make available to the Party, which is undertaking and controlling the defence of any Third Party Claim (the "Defending Party"),

(a) those employees and other persons whose assistance, testimony or presence is necessary to assist the Defending Party in evaluating and defending any Third Party Claim; and

(b) all documents, records and other materials in the possession of such Party reasonably required by the Defending Party for its use in defending any Third Party Claim, and shall otherwise cooperate with the Defending Party. The Indemnitor shall be responsible for all reasonable expenses associated with making such documents, records and materials available and for all reasonable expenses (excluding salaries) of any employees or other persons made available by the Indemnitee to the Indemnitor hereunder.

**12.10. Settlement of Third Party Claims**

If an Indemnitor elects to assume the defence of any Third Party Claim as provided in Section 12.8, the Indemnitor shall not be liable for any legal expenses subsequently incurred by the Indemnitee in connection with the defence of such Third Party Claim following the receipt by the Indemnitee of notice of such assumption. However, if the Indemnitor fails to take reasonable steps necessary to defend diligently such Third Party Claim within 30 days after receiving notice from the Indemnitee that the Indemnitee believes on reasonable grounds that the Indemnitor has failed to take such steps, the Indemnitee may, at its option, elect to assume the defence of and to negotiate, settle or compromise the Third Party Claim assisted by counsel of its own choosing and the Indemnitor shall also be liable for all reasonable costs and expenses paid or incurred in connection therewith. The Indemnitor shall not, without the prior written consent of the Indemnitee, enter into any compromise or settlement of a Third Party Claim, which would lead to liability or create any other obligation, financial or otherwise, on the Indemnitee.

**12.11. Direct Claims**

Any Direct Claim shall be asserted by giving the Indemnitor reasonably prompt written notice thereof, but in any event not later than 60 days after the Indemnitee becomes aware of such Direct Claim. The Indemnitor shall then have a period of 30 days within which to respond in writing to such Direct Claim. If the Indemnitor does not so respond within such 30 day period, the Indemnitor shall be deemed to have rejected such Claim, and in such event the Indemnitee shall be free to pursue such remedies as may be available to the Indemnitee.

**12.12. Failure to Give Timely Notice**

Except as described in Section 12.5, a failure to give timely notice as provided in this Article 12 shall not affect the rights or obligations of any Party except and only to the extent that, as a result of such failure, any Party which was entitled to receive such notice was deprived of its right to recover any payment under its applicable insurance coverage or was otherwise directly and materially damaged as a result of such failure.

**12.13. Reductions and Subrogation**

If the amount of any Loss at any time subsequent to the making of an Indemnity Payment in respect of that Loss is reduced by any recovery, settlement or otherwise under or pursuant to any insurance coverage, or pursuant to any claim, recovery, settlement or payment by or against any other person, the amount of such reduction (less any costs, expenses, including Taxes, or premiums incurred in connection therewith), shall promptly be repaid by the Indemnitee to the Indemnitor. Upon making a full Indemnity Payment, the Indemnitor shall, to the extent of such Indemnity Payment, be subrogated to all rights of the Indemnitee against any third party that is not an Affiliate of the Indemnitee in respect of the Loss to which the Indemnity Payment relates. Until the Indemnitee recovers full payment of its Loss, any and all claims of the Indemnitor against any such third party on account of such Indemnity Payment shall be postponed and subordinated in right of payment to the Indemnitee's rights against such third party. Without limited the generality or effect of any provision hereof, the Indemnitee and Indemnitor shall duly execute upon request all instruments reasonably necessary to evidence and perfect such postponement and subordination.

**12.14. Tax Effect**

If any Indemnity Payment received by an Indemnitee would constitute taxable income to such Indemnitee, the Indemnitor shall pay to the Indemnitee at the same time and on the same terms, as to interest and otherwise, as the Indemnity Payment an additional amount sufficient to place the Indemnitee in the same after-Tax position as it would have been if the Indemnity Payment have been received tax-free.

**12.15. Payment and Interest**

All Losses shall bear interest at a rate per annum equal to the Bank of Canada's prime rate, calculated and payable monthly, both before and after judgment, with interest on overdue interest at the same rate, from the date that the Indemnitee disburse funds, suffered damages or losses or incurred a loss, liability or expense in respect of a Loss, to the date of payment by the Indemnitor to the Indemnitee.

**12.16. Additional Rules and Procedures**

(a) If any Third Party Claim is of a nature such that the Indemnitee is required by Law to make a payment to any person (a "Third Party") with respect to such Third Party Claim before the completion of settlement negotiations or related legal proceedings, the Indemnitee may make such payment and the Indemnitor shall, forthwith after demand by the Indemnitee, reimburse the Indemnitee for any such payment. If the amount of any liability under the Third Party Claim in respect of which such a payment was made, as finally determined, is less than the amount which was paid by the Indemnitor to the Indemnitee, the Indemnitee shall, forthwith after receipt of the difference from the Third Party, pay such difference to the Indemnitor;

(b) The Indemnitee and the Indemnitor shall co-operate fully with each other with respect to Third Party Claims, shall keep each other fully advised with respect thereto (including supplying copies of relevant documentation promptly as it becomes available) and shall each designate a senior officer who will keep himself informed about and be prepared to discuss the Third Party Claim with his counterpart and with counsel at all reasonable times.

## 13. GENERAL

### 13.1. Confidentiality and Exclusivity

The confidentiality and exclusivity provisions described in sections 9 and 10 of the Letter of Intent shall continue to apply to each party, and the terms of this Agreement shall be deemed to be confidential information.

### 13.2. Further Assurances

Each of the Parties agrees, that upon the written request of any other Party, it shall do, execute, acknowledge and deliver, or cause to be done, executed, acknowledged and delivered, all such further acts, deeds, documents, assignments, transfers, conveyances, powers of attorney and assurances as may be reasonably necessary or desirable to effect complete consummation of the transactions herein contemplated.

### 13.3. Notices

13.3.1 Any notice, direction or other instrument required or permitted to be given to any Party hereunder shall be in writing and shall be sufficiently given if delivered personally, or if sent by registered prepaid mail, or if transmitted by facsimile or other form of electronic communication during the transmission of which no indication of failure of receipt is communicated to the sender:

To the Vendor:

The Corporation of the Town of Goderich
57 West Street
Goderich, Ontario N7A 2K5
519-524-8344 (phone)

Attn: Chief Administrative Officer

To the Purchaser:

ERTH Corporation
180 Whiting Street
Ingersoll, Ontario N5C 3B5
888-304-5558 (phone)

Attn: President & CEO

13.3.2 Any such notice, direction or other instrument, if delivered personally, shall be deemed to have been given and received on the day on which it was delivered, provided that if such day is not a Business Day then the notice, direction or other instrument shall be deemed to have been given and received on the first Business Day next following such day; if mailed, shall be deemed to have been given and received on the fourth day after it was mailed, in respect of mail delivered within Canada, or on the sixth day after it was mailed, in respect of mail delivered outside of Canada, provided that it such day is not a Business Day then the notice, direction or other instrument shall be deemed to have been given and received on the first Business Day next following such day; and if transmitted by fax or other form of electronic communication, shall be deemed to have been given and received on the day of its transmission if received by 4 p.m. EST, provided that if such day is not a Business Day or if it is transmitted or received after the end of normal business hours then the notice, direction or other instrument shall be deemed to have been given and received on the first Business Day next following the day of such transmission.

13.3.3 Any Party may change its address for service from time to time by giving notice to each of the other Parties in accordance with the foregoing provisions.

**13.4. Time of the Essence**

Time shall be of the essence of this Agreement.

**13.5. Expenses**

Except as contemplated by or disclosed in this Agreement, all costs and expenses (including, without limitation, the fees and disbursements of legal counsel) incurred in connection with this Agreement and the transactions herein contemplated shall be paid by the Party incurring such costs and expenses.

**13.6. Applicable Law**

This Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein, and shall be treated, in all respects, as an Ontario contract.

**13.7. Entire Agreement**

This Agreement, including the Schedules hereto, constitute the entire agreement between the Parties with respect to the transactions herein contemplated, and supersede all prior understandings, agreements, negotiations and discussions between the Parties with respect thereto except as specifically provided or contemplated in this Agreement or in any agreement, certificate, affidavit or other document delivered or given pursuant to this Agreement. There are no representations, warranties, terms, conditions, undertakings or collateral agreements or understandings, express or implied, between the Parties other than those expressly set forth in this Agreement or in any such agreement, certificate, affidavit, or other document as aforesaid. This Agreement may not be amended or modified in any respect except by written instrument executed by each of the Parties.

### 13.8. Effect of Closing

Any provision of this Agreement which is capable of being performed after but which has not been performed at the Closing, and all obligations, covenants and agreements contained in this Agreement or in any agreement, certificate, affidavit, or other document delivered or given pursuant to this Agreement, including, without limitation, the indemnities herein provided for, shall remain in full force and effect notwithstanding the Closing subject to the limitation periods contained herein.

### 13.9. Counterparts

This Agreement and the Schedules hereto may be executed by the Parties in separate counterparts; each of which when so executed and delivered shall be an original and all such counterparts shall together constitute one and the same Agreement. This Agreement and the Schedules hereto may be executed by facsimile signature.

### 13.10. Assignment

Neither this Agreement nor any rights or obligations hereunder shall be assignable by any Party without the prior written consent of all of the other Parties.

### 13.11. Successors and Assigns

This Agreement shall enure to the benefit of and be binding upon the Parties and their respective heirs, executors, administrators, successors including any successor by reason of the amalgamation or merger of any Party.

### 13.12. Severability of Provisions

Any provision in this Agreement which his prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof or affecting the validity or enforceability of such provision in any other jurisdiction.

***- The remainder of this page is intentionally blank. -***

**IN WITNESS WHEREOF** the parties have hereunto set their hands and seals and the Corporations have hereunto caused to be affixed their corporate seal under the hands of the duly authorized officers.

SIGNED, SEALED AND DELIVERED
in the presence of

) **THE CORPORATION OF THE**
) **TOWN OF GODERICH**
) [redacted]
) Name: [redacted]
) Title: [redacted]
) [redacted]
) Name: [redacted]
) Title: [redacted].

We have authority to bind the Corporation.

) **ERTH CORPORATION**
) [redacted]
) Name: [redacted]
) Title: [redacted]
) [redacted]
) Name: [redacted]
) Title: [redacted]

We have the authority to bind the Corporation.

# ATTACHMENT 6

# RESOLUTIONS APPROVING TRANSACTION

**Dwayne Evans,** M.P.A., MCIP, RPP
*Clerk/Planning Coordinator*

July 28, 2017

Attn: Chris White
ERTH Corporation
180 Whiting Street
Ingersoll, ON
N5C 3B5

Dear Mr. White,

RE: Letter of Intent – Amalgamation of West Coast Huron Energy Inc. and Erie Thames Powerlines Corporation in exchange for shares in ERTH Corporation

Please be advised of the following resolution passed at the July 17, 2017 regular meeting of Council;

Moved by: Councillor Bazinet
Seconded by: Councillor Murdock

***WHEREAS*** *the Town of Goderich (the "Town") is the sole shareholder of West Coast Huron Energy Inc. ("Goderich Hydro" a licensed electricity distributor incorporated under section 142 of the Electricity Act, 1998 (Ontario) servicing residents of the Town;*

***AND WHEREAS*** *ERTH Corporation ("ERTH") is the sole shareholder of Erie Thames Powerlines Corporation ("Erie Thames"), a licensed electricity distributor incorporated under section 142 of the Electricity Act (Ontario) servicing residents of ERTH's eight shareholder municipalities;*

***AND WHEREAS*** *ERTH has made a proposal to the Town to merge Goderich Hydro with Erie Thames in exchange for shares in ERTH and other consideration (the "Merger") as detailed in a non-binding letter of intent in the form attached as Schedule A to this resolution (the "LOI");*

***AND WHEREAS,*** *after discussions with ERTH and a review of the other options available to Goderich Hydro, including the status quo and other merger partners, the board of directors of Goderich Hydro (the "Hydro Board") recommend that the Town execute the LOI authorizing the parties to attempt to complete the merger of Goderich Hydro and Erie Thames on the terms and conditions described in the LOI;*

***AND WHEREAS*** *the information described above, including the LOI and an overview of Goderich Hydro's options, was presented to Council at its meeting on June 26, 2017.*

Town Hall
57 West Street
Goderich, Ontario
Canada N7A 2K5

Tel: 519-524-8344
Fax: 519-524-7209
devans@goderich.ca
www.goderich.ca

GODERICH
*Canada's prettiest town*

***BE IT RESOLVED THAT:***

1. *The non-binding LOI, in the form attached to this resolution as Schedule A is hereby approved and the Mayor and Clerk are hereby authorized and directed to execute the LOI on behalf of the Town.*
2. *Upon execution of the LOI, the Hydro Board is appointed as shareholder representative for the express purpose of undertaking the steps described in the LOI, including the completion of due diligence, the negotiation and execution of definitive legal agreements, the submission of an application to the Ontario Energy Board requesting regulatory approval, and all other necessary steps required to finalize and consummate the Merger.*
   - *As a condition of proceeding with the steps described in paragraph 2 above:*
     - *The Hydro Board is directed to provide progress reports to Council at regular intervals with respect to the steps described in paragraph 2, including the closing of the Merger.*
     - *In the event of any material change to the terms and conditions of the Merger as described in the LOI, the Hydro Board shall return to Council for further approval or direction.*

Councillor Elliott requests a recorded vote. The Clerk records accordingly. The motion is carried on a vote of five (5) yeas and two (2) nays, as follows:

Yeas: Mayor Morrison, Deputy Mayor Donnelly, Councillor Hansen, Councillor Bazinet and Councillor Murdock

Nays: Councillor Hoy and Councillor Elliott

CARRIED

Please see an executed copy of the above noted letter of intent attached.

Yours truly,

[redacted]

Dwayne Evans
Clerk/Planning Coordinator

DE

Encl.

**RESOLUTIONS OF THE SHAREHOLDERS**
**OF**
**ERTH CORPORATION**
**(the "Corporation")**

**MERGER WITH WEST COAST HURON ENERGY INC. (GODERICH HYDRO)**

**DATE: August 10th, 2017**

**WHEREAS** sections 4.1(6) of the Corporation's shareholder agreement requires Special Shareholder Approval of the transaction contemplated in this special resolution.

**RESOLVE THAT:**

1. The following transactions, pursuant to the terms presented at the special shareholder meeting on August 10, 2017 and as reflected in the non-binding letter of intent ("LOI") attached to this resolution as Schedule "A", are hereby approved;

    a. The acquisition of all of the issued and outstanding shares of West Coast Huron Energy Inc. by ERTH Corporation ("ERTH"), and

    b. The issuance of the Town of Goderich of one Class A share and 6,095,924 Class B shares (representing an ownership position of 22.5%) in the capital of ERTH;

2. The ERTH Board of Directors ("the Board") be appointed as shareholder representatives for the express purpose of approving the final form of agreements and taking all other necessary steps to finalize and consummate the transactions described herein; and

The Board shall return to its shareholders for further approval in the event of any material change to the terms and conditions described in the LOI

The foregoing resolution is, by the signature below of the Chair of the Corporation, approved and passed by two-thirds of the Shareholders of the Corporation pursuant to the provisions of the *Business Corporations Act* (Ontario) and the Corporation's shareholder agreement.

DATED the 10th day of August, 2017.

Moved: [redacted]

Seconded: [redacted]

Carried: [redacted]

# ATTACHMENT 7

# FINANCIAL STATEMENTS – ERIE THAMES POWERLINES - 2016

# ERIE THAMES POWERLINES CORPORATION

## FINANCIAL STATEMENTS

## DECEMBER 31, 2016

Your Home Town Utility

**ERIE THAMES POWERLINES CORPORATION**
**INDEX TO FINANCIAL STATEMENTS**
**DECEMBER 31, 2016**

KPMG LLP
140 Fullarton Street Suite 1400
London ON N6A 5P2
Canada
Tel 519 672-4800
Fax 519 672-5684

# INDEPENDENT AUDITORS' REPORT

To the Shareholder of Erie Thames Powerlines Corporation,

We have audited the accompanying financial statements of Erie Thames Powerlines Corporation, which comprise the statement of financial position as at December 31, 2016, the statements of profit or loss and other comprehensive income, changes in equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

*Management's Responsibility for the Financial Statements*

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

*Auditors' Responsibility*

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

*Opinion*

In our opinion, the financial statements present fairly, in all material respects, the financial position of Erie Thames Powerlines Corporation as at December 31, 2016, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards**.**

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 20, 2017

London, Canada

**ERIE THAMES POWERLINES CORPORATION**
**STATEMENT OF FINANCIAL POSITION**
**AS AT DECEMBER 31, 2016**

| | | 2016 | 2015 |
|---|---|---|---|
| **Assets** | | | |
| **Current assets** | | | |
| Accounts receivable | 6 | $ 5,845,546 | $ 4,852,917 |
| Due from related parties | 26 | 141,813 | 97,157 |
| Materials and supplies | 7 | 88,158 | 86,525 |
| Unbilled revenue | | 6,817,837 | 5,616,740 |
| Prepaid expenses | | 92,441 | 82,070 |
| Payments in lieu of income taxes receivable | | 16,646 | 204,555 |
| Total current assets | | 13,002,441 | 10,939,964 |
| **Non-current assets** | | | |
| Property, plant and equipment | 9 | 36,834,241 | 34,079,941 |
| Intangible assets | 10 | 487,595 | 597,850 |
| Investments | 8 | 25,584 | 21,415 |
| Deferred tax assets | 11 | - | 37,000 |
| Total non-current assets | | 37,347,420 | 34,736,206 |
| **Total assets** | | 50,349,861 | 45,676,170 |
| Regulatory balances | 12 | 7,933,983 | 6,154,937 |
| **Total assets and regulatory balances** | | $58,283,844 | $51,831,107 |

## ERIE THAMES POWERLINES CORPORATION
### STATEMENT OF FINANCIAL POSITION
### AS AT DECEMBER 31, 2016

| | | 2016 | 2015 |
|---|---|---|---|
| **Liabilities** | | | |
| **Current liabilities** | | | |
| Bank indebtedness | 13 | $ 2,507,866 | $ 1,695,391 |
| Accounts payable and accrued liabilities | 14 | 10,949,045 | 8,373,376 |
| Due to related parties | 26 | 351,078 | 903,121 |
| Long-term debt due within one year | 15 | 192,612 | 108,049 |
| Customer deposits | | 345,866 | - |
| Deferred revenue | | 442,724 | 472,282 |
| **Total current liabilities** | | 14,789,191 | 11,552,219 |
| **Non-current liabilities** | | | |
| Long-term debt | 15 | 20,740,791 | 20,303,625 |
| Post-employment benefits | 16 | 797,100 | 829,100 |
| Customer deposits | | 606,215 | 760,379 |
| Deferred revenue | | 1,903,060 | 1,315,009 |
| Deferred tax liability | 11 | 231,000 | - |
| Total non-current liabilities | | 24,278,166 | 23,208,113 |
| **Total liabilities** | | 39,067,357 | 34,760,332 |
| **Equity** | | | |
| Share capital | 17 | 10,855,585 | 10,855,585 |
| Retained earnings | | 3,809,844 | 2,800,310 |
| Accumulated other comprehensive loss | | (38,837) | (110,806) |
| **Total equity** | | 14,626,592 | 13,545,089 |
| **Total liabilities and equity** | | 53,693,949 | 48,305,421 |
| Regulatory balances | 12 | 4,589,895 | 3,525,686 |
| **Total liabilities, equity and regulatory balances** | | $58,283,844 | $51,831,107 |

Commitments and contingencies (note 23)
Guarantee (note 24)

**APPROVED ON BEHALF OF THE BOARD:**

[redacted] Director

[redacted] Director

**ERIE THAMES POWERLINES CORPORATION**
**STATEMENT OF COMPREHENSIVE INCOME**
**FOR THE YEAR ENDED DECEMBER 31, 2016**

| | | 2016 | 2015 |
|---|---|---|---|
| **Revenues** | | | |
| Sale of energy | | $60,612,620 | $53,673,716 |
| Distribution revenue | | 10,098,899 | 9,790,667 |
| Other | 18 | 533,497 | 473,117 |
| | | 71,245,016 | 63,937,500 |
| **Operating expenses** | | | |
| Cost of power purchased | | 61,006,324 | 54,426,015 |
| Employee salaries and benefits | 19 | 3,182,316 | 3,338,522 |
| Operating expenses | 20 | 3,158,049 | 2,852,891 |
| Depreciation and amortization | | 1,741,257 | 1,544,499 |
| | | 69,087,946 | 62,161,927 |
| **Income from operating activities** | | 2,157,070 | 1,775,573 |
| Finance costs | 21 | 1,559,373 | 1,320,728 |
| **Income before income taxes** | | 597,697 | 454,845 |
| Income tax expense | 11 | 284,000 | 264,000 |
| **Net income for the year** | | 313,697 | 190,845 |
| Net movement in regulatory balances, net of tax | 12 | (695,837) | (762,959) |
| **Net income for the year and net movement in regulatory balances** | | **1,009,534** | **953,804** |
| | | | |
| **Other comprehensive income** | | | |
| Items that will be reclassified to profit or loss: | | | |
| Change in fair value of investments | | 4,169 | 610 |
| Items that will not be reclassified to profit or loss: | | | |
| Remeasurement of post-employment benefits | 16 | 67,800 | 500 |
| Tax on remeasurements | 11 | (19,000) | - |
| Net movement in regulatory balances, net of tax | 12 | 19,000 | - |
| **Other comprehensive income** | | 71,969 | 1,110 |
| **Total comprehensive income for the year** | | **$ 1,081,503** | **$ 954,914** |

**ERIE THAMES POWERLINES CORPORATION**
**STATEMENT OF CHANGES IN EQUITY**
**FOR THE YEAR ENDED DECEMBER 31, 2016**

| | Share capital | Retained earnings | Accumulated other comprehensive loss | Total |
|---|---|---|---|---|
| **Balance at January 1, 2015** | $10,855,585 | $ 3,846,506 | $ (111,916) | $14,590,175 |
| Net income and net movement in regulatory balances | - | 953,804 | - | 953,804 |
| Other comprehensive loss | - | - | 1,110 | 1,110 |
| Dividends | - | (2,000,000) | - | (2,000,000) |
| **Balance at December 31, 2015** | $10,855,585 | $ 2,800,310 | $ (110,806) | $13,545,089 |
| | | | | |
| **Balance at January 1, 2016** | $10,855,585 | $ 2,800,310 | $ (110,806) | $13,545,089 |
| Net income and net movement in regulatory balances | - | 1,009,534 | - | 1,009,534 |
| Other comprehensive income | - | - | 71,969 | 71,969 |
| **Balance at December 31, 2016** | $10,855,585 | $ 3,809,844 | $ (38,837) | $14,626,592 |

**ERIE THAMES POWERLINES CORPORATION**
**STATEMENT OF CASH FLOWS**
**FOR THE YEAR ENDED DECEMBER 31, 2016**

| | 2016 | 2015 |
|---|---|---|
| **Operating activities** | | |
| Net income and net movement in regulatory balances | $ 1,009,534 | $ 953,804 |
| Adjustments for: | | |
| Depreciation and amortization | 1,741,257 | 1,544,499 |
| Amortization of deferred revenue | (28,635) | (19,080) |
| Post-employee benefits | 35,800 | 34,700 |
| Loss (gain) on disposal of property, plant and equipment | (61,534) | 20,829 |
| Finance costs | 1,559,373 | 1,320,728 |
| Income tax expense | 284,000 | 264,000 |
| | 4,539,795 | 4,119,480 |
| **Changes in non-cash operating working capital:** | | |
| Accounts receivable | (992,628) | 203,616 |
| Due to related parties | (596,699) | (82,952) |
| Unbilled revenue | (1,201,097) | (657,507) |
| Materials and supplies | (1,633) | 83,454 |
| Prepaid expenses | (10,371) | 30,897 |
| Accounts payable and accrued liabilities | 2,575,669 | (979,943) |
| Customer deposits | 191,702 | 7,822 |
| | (35,057) | (1,394,613) |
| Regulatory balances | (695,837) | (762,959) |
| Income tax refund (paid) | 152,909 | (398,250) |
| **Net cash from operating activities** | 3,961,810 | 1,563,658 |
| **Investing activities** | | |
| Purchase of property, plant and equipment | (4,356,503) | (5,046,077) |
| Proceeds on disposal of property, plant and equipment | 61,534 | 21,583 |
| Purchase of intangible assets | (28,800) | (168,360) |
| Contributions received from customers | 587,128 | 781,458 |
| **Net cash used by investing activities** | (3,736,641) | (4,411,396) |
| **Financing activities** | | |
| Dividends paid | - | (2,000,000) |
| Interest paid | (1,559,373) | (1,320,728) |
| Proceeds from long-term debt | - | 10,000,000 |
| Proceeds from finance leases | 682,061 | - |
| Repayment of finance leases | (160,332) | (115,596) |
| **Net cash from financing activities** | (1,037,644) | 6,563,676 |
| Change in bank indebtedness | (812,475) | 3,715,938 |
| Bank indebtedness, beginning of year | (1,695,391) | (5,411,329) |
| **Bank indebtedness, end of year** | $ (2,507,866) | $ (1,695,391) |

## 1. Reporting entity

Erie Thames Powerlines Corporation ("the Corporation") is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the Town of Ingersoll. The address of the Corporation's registered office is 143 Bell Street, PO Box 157 Ingersoll ON (Canada) N5C 3K5.

The Corporation delivers electricity and related energy services to residential and commercial customers in Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, Thamesford, Clinton, Mitchell and Dublin. The Corporation is wholly owned by the following eight municipalities, each of whom has one voting common share: Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford, Zorra and West Perth.

The financial statements are for the Corporation as at and for the year ended December 31, 2016.

## 2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 20, 2017.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest dollar.

(d) Use of estimates and judgments

(i) Assumptions and estimation uncertainty

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

**2. Basis of presentation (continued)**

(d) Use of estimates and judgments (continued)

(i) Assumptions and estimation uncertainty (continued)

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Note 3(b) – measurement of unbilled revenue
(ii) Notes 9, 10 – estimation of useful lives of its property, plant and equipment and estimation of fair value of goodwill and intangible assets
(iii) Note 12 – recognition and measurement of regulatory balances
(iv) Note 16 – measurement of defined benefit obligations: key actuarial assumptions
(v) Note 23 – recognition and measurement of provisions and contingencies

(ii) Judgments

Information about judgments made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following notes:

- Note 9 – leases: whether an arrangement contains a lease

(e) Rate regulation

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The Corporation is required to bill customers for the debt retirement charge set by the province. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation ("OEFC") once each year.

Rate setting

*Distribution revenue*

For the distribution revenue included in sale of energy, the Corporation files a "Cost of Service" ("COS") rate application with the OEB every five years where rates are determined through a review of the forecasted annual amounts of operating and capital expenditures, debt and shareholder's equity required to support the Corporation's business. The Corporation forecasts electricity usage and the costs to service each customer class to determine the appropriate rates to be charged. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

**2. Basis of presentation (continued)**

(e) Rate regulation (continued)

In the intervening years an Incentive Rate Mechanism application (“IRM”) is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year’s rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand (“GDP IPI-FDD”) net of a productivity factor and a “stretch factor” determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application on June 26, 2012 for rates effective January 1, 2013 to April 30, 2013. On October 19, 2015 an IRM application was filed with the OEB for rates effective May 1, 2016 until April 30, 2017. Within this application the approved GDP IPI-FDD is 1.60%, the Corporation’s productivity factor is 0.00% and the stretch factor is 0.30%, resulting in a net increase of 1.80% to the previous year’s rates.

*Electricity rates*

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

**3. Significant accounting policies**

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments

All financial assets are classified as loans and receivables, except for investments which are classified as available for sale, and all financial liabilities are classified as other liabilities. These financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(f). Available for sale assets are subsequently measured at their fair value, with changes in fair value recognized in other comprehensive income (“OCI”) until the asset is sold.

The Corporation does not enter into derivative instruments. Hedge accounting has not been used in the preparation of these financial statements.

**3. Significant accounting policies (continued)**

(b) Revenue recognition

*Sale and distribution of electricity*

Revenue from the sale and distribution of electricity is recognized as the electricity is delivered to customers on the basis of cyclical meter readings and estimated customer usage since the last meter reading date to the end of the year. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

*Other revenue*

Revenue earned from the provision of services is recognized as the service is rendered.

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. Cash contributions are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Government grants and the related performance incentive payments under CDM programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Materials and supplies

Materials and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

**3. Significant accounting policies (continued)**

(d) Property, plant and equipment

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

| | Years |
|---|---|
| Buildings | 55 - 60 |
| Automotive equipment | 8 - 10 |
| Computer equipment | 5 - 15 |
| Services, office and other equipment | 5 - 8 |
| Transmission and distribution system | 12 - 60 |

**3. Significant accounting policies (continued)**

(e) Intangible assets

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost, less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

Goodwill represents the excess of cost over fair value of net assets of businesses acquired. Goodwill is measured at cost less accumulated impairment losses.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate.

The estimated useful lives are:

| | Years |
|---|---|
| Computer software | 5 - 10 |
| Goodwill | indefinite life |
| Land rights | indefinite life |

(f) Impairment

(i) Financial assets measured at amortized cost

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss is calculated as the difference between an asset’s carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

**3. Significant accounting policies (continued)**

(f) Impairment (continued)

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorate basis, if applicable.

An impairment loss in respect of goodwill is not reversed. For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(g) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

**3. Significant accounting policies (continued)**

(i) Regulatory balances

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“the Fund”), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

**3. Significant accounting policies (continued)**

(j) Post-employment benefits

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Remeasurements of the net defined benefit obligations, including actuarial gains and losses, are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(k) Leased assets

Leases, where the terms cause the Corporation to assume substantially all the risks and rewards of ownership, are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

All other leases are classified as operating leases and the leased assets are not recognized on the Corporation's statement of financial position. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease.

(l) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents and dividend income.

Finance costs comprise interest expense on borrowings, finance lease obligations and unwinding of the discount on provisions, net interest expense on post-employment benefits and impairment losses on financial assets. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(m) Income taxes

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

**3. Significant accounting policies (continued)**

(m) Income taxes (continued)

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

***4.*** **Standards issued but not yet adopted**

*Future accounting changes*

There are new standards, amendments to standards and interpretations which have not been applied in preparing these financial statements.

(a) *Annual Improvements to IFRS (2014-2016) cycle.* On December 8, 2016 the IASB issued narrow-scope amendments to three standards as part of its annual improvements process.

Each of the amendments has its own specific transition requirements and effective date.

Amendments were made to the following standards:

- Clarification that IFRS 12 *Disclosures of Interests in Other Entities* also applies to interests that are classified as held for sale, held for distribution, or discontinued operations, effective retrospectively for annual periods beginning on or after January 1, 2017;
- Removal of out-dated exemptions for first time adopters under IFRS 1 *First-time Adoption of International Financial Reporting Standards*, effective for annual periods beginning on or after January 1, 2018; and
- Clarification that the election to measure an associate or joint venture at fair value under IAS 28 *Investments in Associates and Joint Ventures* for investments held directly, or indirectly, through a venture capital or other qualifying entity can be made on an investment-by-investment basis. The amendments are effective retrospectively for annual periods beginning on or after January 1, 2018.

The Corporation intends to adopt these amendments in its financial statements for the annual period beginning on January 1, 2017 or 2018 as applicable. The extent of the impact of adoption of the amendments has not yet been determined.

**4. Standards issued but not yet adopted (continued)**

(b) On December 8, 2016, the IASB issued IFRIC Interpretation 22 *Foreign Currency Transactions and Advance Consideration.*

The Interpretation clarifies which date should be used for translation when a foreign currency transaction involves an advance payment or receipt.

The Interpretation is applicable for annual periods beginning on or after January 1, 2018. Earlier application is permitted.

The Interpretation clarifies that the date of the transaction for the purpose of determining the exchange rate to use on initial recognition of the related asset, expense or income (or part of it) is the date on which an entity initially recognizes the non-monetary asset or non-monetary liability arising from the payment or receipt of advance consideration.

The Interpretation may be applied either:

- retrospectively; or
- prospectively to all assets, expenses and income in the scope of the Interpretation initially recognized on or after:
- the beginning of the reporting period in which the entity first applies the Interpretation; or
- the beginning of a prior reporting period presented as comparative information in the financial statements.

The Company intends to adopt the Interpretation in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of adoption of the Interpretation has not yet been determined.

(c) On May 28, 2014 the IASB issued *IFRS 15 Revenue from Contracts with Customers*. The new standard is effective for annual periods beginning on or after January 1, 2018. Earlier application is permitted. IFRS 15 will replace IAS 11 Construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programs, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfer of Assets from Customers, and SIC 31 Revenue – Barter Transactions Involving Advertising Services.

On April 12, 2016, the IASB issued *Clarifications to IFRS 15, Revenue from Contracts with Customers*, which is effective at the same time as IFRS 15.

The standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized.

## 4. Standards issued but not yet adopted (continued)

The new standard applies to contracts with customers. It does not apply to insurance contracts, financial instruments or lease contracts, which fall in the scope of other IFRSs.

The clarifications to IFRS 15 provide additional guidance with respect to the five-step analysis, transition, and the application of the Standard to licenses of intellectual property.

The Company intends to adopt IFRS 15 and the clarifications in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of adoption of the standard has not yet been determined.

(d) On July 24, 2014 the IASB issued the complete *IFRS 9 (IFRS 9 (2014))*. The mandatory effective date of IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted. The restatement of prior periods is not required and is only permitted if information is available without the use of hindsight.

IFRS 9 (2014) introduces new requirements for the classification and measurement of financial assets. Under IFRS 9 (2014), financial assets are classified and measured based on the business model in which they are held and the characteristics of their contractual cash flows.

The standard introduces additional changes relating to financial liabilities.

It also amends the impairment model by introducing a new ‘expected credit loss’ model for calculating impairment.

IFRS 9 (2014) also includes a new general hedge accounting standard which aligns hedge accounting more closely with risk management. This new standard does not fundamentally change the types of hedging relationships or the requirement to measure and recognize ineffectiveness, however it will provide more hedging strategies that are used for risk management to qualify for hedge accounting and introduce more judgment to assess the effectiveness of a hedging relationship.

Special transitional requirements have been set for the application of the new general hedging model.

The Corporation intends to adopt IFRS 9 (2014) in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of adoption of the standard has not yet been determined.

(e) On January 13, 2016 the IASB issued *IFRS 16 Leases*. The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 Revenue from Contracts with Customers at or before the date of initial adoption of IFRS 16. IFRS 16 will replace IAS 17 Leases.

This standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments.

This standard substantially carries forward the lessor accounting requirements of IAS 17, while requiring enhanced disclosures to be provided by lessors.

**4. Standards issued but not yet adopted (continued)**

Other areas of the lease accounting model have been impacted, including the definition of a lease. Transitional provisions have been provided.

The Corporation intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The extent of the impact of adoption of the standard has not yet been determined.

(f) On January 7, 2016 the IASB issued *Disclosure Initiative* (Amendments to IAS 7). The amendments apply prospectively for annual periods beginning on or after January 1, 2017. Earlier application is permitted.

The amendments require disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flow and non-cash changes. One way to meet this new disclosure requirement is to provide a reconciliation between the opening and closing balances for liabilities from financing activities.

The Company will adopt the amendments to IAS 7 in its financial statements for the annual period beginning on January 1, 2017. The Company does not expect the amendments to have a material impact on the financial statements.

(g) On January 19, 2016 the IASB issued *Recognition of Deferred Tax Assets for Unrealized Losses* (Amendments to IAS 12). The amendments apply retrospectively for annual periods beginning on or after January 1, 2017. Earlier application is permitted.

The amendments clarify that the existence of a deductible temporary difference depends solely on a comparison of the carrying amount of an asset and its tax base at the end of the reporting period, and is not affected by possible future changes in the carrying amount or expected manner of recovery of the asset.

The amendments also clarify the methodology to determine the future taxable profits used for assessing the utilization of deductible temporary differences.

The Company will adopt the amendments to IAS 12 in its financial statements for the annual period beginning on January 1, 2017. The extent of the impact of adoption of the amendments has not yet been determined.

## 5. Change in accounting policies

There are new standards, amendments to standards and interpretations which have been applied in preparing these financial statements.

(a) *Annual Improvements to IFRS (2012-2014) cycle*. On September 25, 2014 the IASB issued narrow-scope amendments to a total of four standards as part of its annual improvements process. The amendments apply for annual periods beginning on or after January 1, 2016. Each of the amendments has its own specific transition requirements.

Amendments were made to clarify the following in their respective standards:

- Changes in method for disposal under IFRS 5 Non-current Assets Held for Sale and Discontinued Operations;
- ‘Continuing involvement’ for servicing contracts and offsetting disclosures in condensed interim financial statements under IFRS 7 Financial Instruments: Disclosures;
- Discount rate in a regional market sharing the same currency under IAS 19 Employee Benefits;
- Disclosure of information ‘elsewhere in the interim financial report’ under IAS 34 Interim Financial Reporting;

The Corporation adopted these amendments in its financial statements for the annual period beginning on January 1, 2016. The amendments did not have a material impact on the financial statements.

## 6. Accounts receivable

| | 2016 | 2015 |
|---|---|---|
| Trade receivables | $ 5,113,712 | $ 3,807,167 |
| Billable work | 731,834 | 1,045,750 |
| | $ 5,845,546 | $ 4,852,917 |

## 7. Materials and supplies

Amounts written down due to obsolescence in 2016 was nil (2015 - nil).

## 8. Investments

The Corporation holds 1,812 Common shares of Sunlife Financial with a fair value at December 31, 2016 of $25,584 (2015 - $21,415).

## 9. Property, plant and equipment

| | Land and buildings | Distribution equipment | Other fixed assets | Construction in progress | Total |
|---|---|---|---|---|---|
| *Cost or deemed cost* | | | | | |
| Balance at Jan. 1, 2016 | $ 220,945 | $ 32,390,048 | $ 2,561,581 | $ 1,198,503 | $ 36,371,077 |
| Additions | 74,506 | 18,638 | 811,014 | 3,452,345 | 4,356,503 |
| Transfers | - | 3,660,256 | - | (3,660,256) | - |
| Disposals/retirements | - | (853,930) | (487,093) | - | (1,341,023) |
| Balance at Dec. 31, 2016 | $ 295,451 | $ 35,215,012 | $ 2,885,502 | $ 990,592 | $ 39,386,557 |
| | | | | | |
| Balance at Jan. 1, 2015 | $ 220,945 | $ 28,712,833 | $ 2,077,928 | $ 701,998 | $ 31,713,704 |
| Additions | - | 3,238,593 | 608,981 | 1,198,503 | 5,046,077 |
| Transfers | - | 701,998 | - | (701,998) | - |
| Disposals/retirements | - | (263,376) | (125,328) | - | (388,704) |
| Balance at Dec. 31, 2015 | $ 220,945 | $ 32,390,048 | $ 2,561,581 | $ 1,198,503 | $ 36,371,077 |
| | | | | | |
| *Accumulated depreciation* | | | | | |
| Balance at Jan. 1, 2016 | $ 6,520 | $ 1,860,523 | $ 424,093 | $ - | $ 2,291,136 |
| Depreciation | 3,260 | 1,226,879 | 372,064 | - | 1,602,203 |
| Disposals/retirements | - | (853,930) | (487,093) | - | (1,341,023) |
| Balance at Dec. 31, 2016, | $ 9,780 | $ 2,233,472 | $ 309,064 | $ - | $ 2,552,316 |
| | | | | | |
| Balance at Jan. 1, 2015 | $ 3,260 | $ 934,267 | $ 278,988 | $ - | $ 1,216,515 |
| Depreciation | 3,260 | 1,147,220 | 270,432 | - | 1,420,912 |
| Disposals/retirements | - | (220,964) | (125,327) | - | (346,291) |
| Balance at Dec. 31, 2015, | $ 6,520 | $ 1,860,523 | $ 424,093 | $ - | $ 2,291,136 |
| | | | | | |
| *Carrying amounts* | | | | | |
| At December 31, 2016 | $ 285,671 | $ 32,981,540 | $ 2,576,438 | $ 990,592 | $ 36,834,241 |
| At December 31, 2015 | 214,425 | 30,529,525 | 2,137,488 | 1,198,503 | 34,079,941 |

The Corporation leases equipment under a number of finance agreements. The leased equipment secures the lease obligations (see note 15). At December 31, 2016, the net carrying amount of leased equipment was $936,592 (2015 - $700,940).

At December 31, 2016 all current and future personal property carrying amount of $36,834,241 (2015 - $34,079,941) are subject to a general security agreement.

During the year, borrowing costs of nil (2015 - nil) were capitalized as part of property, plant and equipment.

PP&E and intangible asset purchase commitments outstanding as at December 31, 2016 are nil (2015 - $335,995).

## 10. Intangible assets

| | Computer software | Land rights | Goodwill | Total |
|---|---|---|---|---|
| *Cost or deemed cost* | | | | |
| Balance at Jan. 1, 2016 | $ 708,510 | $ 43,879 | $ 76,667 | $ 829,056 |
| Additions | 27,000 | 1,800 | - | 28,800 |
| Balance at Dec. 31, 2016 | $ 735,510 | $ 45,679 | $ 76,667 | $ 857,856 |
| Balance at Jan. 1, 2015 | $ 540,150 | $ 43,879 | $ 76,667 | $ 660,696 |
| Additions | 168,360 | - | - | 168,360 |
| Balance at Dec. 31, 2015 | $ 708,510 | $ 43,879 | $ 76,667 | $ 829,056 |
| *Accumulated depreciation* | | | | |
| Balance at Jan. 1, 2016 | $ 231,206 | $ - | $ - | $ 231,206 |
| Depreciation | 139,055 | - | - | 139,055 |
| Balance at Dec. 31, 2016 | $ 370,261 | $ - | $ - | $ 370,261 |
| Balance at Jan. 1, 2015 | $ 107,619 | $ - | $ - | $ 107,619 |
| Depreciation | 123,587 | - | - | 123,587 |
| Balance at Dec. 31, 2015 | $ 231,206 | $ - | $ - | $ 231,206 |
| *Carrying amounts* | | | | |
| At December 31, 2016 | $ 365,249 | $ 45,679 | $ 76,667 | $ 487,595 |
| At December 31, 2015 | 477,304 | 43,879 | 76,667 | 597,850 |

## 11. Income tax expense

Income tax expense

| | 2016 | 2015 |
|---|---|---|
| Current tax | $ 35,000 | $ 28,000 |
| Deferred tax | 268,000 | 236,000 |
| | 303,000 | 264,000 |
| Net movement in regulatory balances | (268,000) | (236,000) |
| | $ 35,000 | $ 28,000 |

Reconciliation of effective tax rate

| | 2016 | 2015 |
|---|---|---|
| Income before taxes | 1,116,503 | 982,914 |
| Canada and Ontario statutory Income tax rates | 26.5 % | 26.5 % |
| Expected tax provision on income at statutory rates | 296,000 | 260,000 |
| Increase (decrease) in income taxes resulting from: | | |
| Permanent difference | 2,000 | 3,000 |
| Recognized deductible temporary differences due to/from customers | (268,000) | (236,000) |
| Other | 5,000 | 1,000 |
| Income tax expense | $ 35,000 | $ 28,000 |

## 11. Income tax expense (continued)

Significant components of the Corporation's deferred tax balances

| | 2016 | 2015 |
|---|---|---|
| Deferred tax assets (liabilities): | | |
| Property, plant and equipment | $ (477,000) | $ (209,000) |
| Cumulative eligible capital | 42,000 | 47,000 |
| Post-employment benefits | 211,000 | 220,000 |
| Other | (7,000) | (21,000) |
| | $ (231,000) | $ 37,000 |

## 12. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances

| | January 1, 2016 | Additions | Recovery/ reversal | December 31, 2016 |
|---|---|---|---|---|
| **Regulatory deferral account debit balances** | | | | |
| Regulatory assets account | $ 5,258,906 | $ (61,617) | $ 270,339 | $ 5,467,628 |
| PILS regulatory adjustment | 308,044 | - | (308,044) | - |
| Regulatory settlement account | 439,251 | 3,148,848 | (1,772,569) | 1,815,530 |
| Smart meters | (3,423) | - | 3,423 | - |
| Stranded meters | 9,773 | - | (9,773) | - |
| LRAM | 86,166 | 148,000 | 100,834 | 335,000 |
| Other regulatory accounts | 56,220 | 29,330 | (725) | 84,825 |
| Deferred income tax | - | 231,000 | - | 231,000 |
| | $ 6,154,937 | $ 3,495,561 | $ (1,716,515) | $ 7,933,983 |

Regulatory settlement account debit balances have a remaining recovery of 1 year. The remaining deferral debit balances have not yet been submitted to the OEB for recovery.

| | January 1, 2015 | Additions | Recovery/ reversal | December 31, 2015 |
|---|---|---|---|---|
| **Regulatory deferral account debit balances** | | | | |
| Regulatory assets account | $ 4,788,507 | $ (1,751,904) | $ 2,222,303 | $ 5,258,906 |
| PILS regulatory adjustment | 118,153 | - | 189,891 | 308,044 |
| Regulatory settlement account | 55,988 | 1,388,982 | (1,005,719) | 439,251 |
| Smart meters | 13,728 | (11,744) | (5,407) | (3,423) |
| Stranded meters | 9,810 | - | (37) | 9,773 |
| LRAM | - | 185,977 | (99,811) | 86,166 |
| Other regulatory accounts | 231 | 55,989 | - | 56,220 |
| | $ 4,986,417 | $ (132,700) | $ 1,301,220 | $ 6,154,937 |

All regulatory deferral account debit balances have a remaining recovery reversal of 2 years.

## 12. Regulatory balances (continued)

| | January 1, 2016 | Additions | Recovery/ reversal | December 31, 2016 |
|---|---|---|---|---|
| **Regulatory deferral account credit balances** | | | | |
| Regulatory liability account | $ 2,181,044 | $ (3,059,457) | $ 4,781,268 | $ 3,902,855 |
| Regulatory settlement account | 331,527 | - | (331,527) | - |
| MIFRS regulatory adjustments | 962,819 | (287,779) | - | 675,040 |
| Other regulatory accounts | 13,296 | - | (1,296) | 12,000 |
| Deferred income tax | 37,000 | - | (37,000) | - |
| | $ 3,525,686 | $ (3,347,236) | $ 4,411,445 | $ 4,589,895 |

The regulatory deferral credit balances have not yet been submitted to the OEB for recovery.

| | January 1, 2015 | Additions | Recovery/ reversal | December 31, 2015 |
|---|---|---|---|---|
| **Regulatory deferral account credit balances** | | | | |
| Regulatory liability account | $ 1,852,982 | $ (1,893,434) | $ 2,221,496 | $ 2,181,044 |
| Regulatory settlement account | 122,799 | - | 208,728 | 331,527 |
| MIFRS regulatory adjustments | 758,465 | 204,354 | - | 962,819 |
| LRAM disposition | 67,181 | - | (67,181) | - |
| Other regulatory accounts | 45,698 | - | (32,402) | 13,296 |
| Deferred income tax | 273,000 | - | (236,000) | 37,000 |
| | $ 3,120,125 | $ (1,689,080) | $ 2,094,641 | $ 3,525,686 |

All regulatory deferral account credit balances have a remaining recovery reversal of 2 years.

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

Settlement of the Group 1 deferral accounts is done on an annual basis through application to the OEB. An application has been made to the OEB to recover $39,783 of the Group 1 deferral accounts. These balances do not produce material rates for most customer classes at this time and as such will not be disposed until the next application.

The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers Acceptances three-month rate plus a spread of 25 basis points. In 2016, the rate was 1.10%.

## 13. Demand operating loan

Through a mirror banking agreement with its parent Company the Corporation has available to its use a $10,000,000 revolving line of credit. The Corporation provides a guarantee on this facility, as outlined in note 24.

## 14. Accounts payable and accrued liabilities

| | **2016** | **2015** |
|---|---|---|
| Trade payables | $ 10,843,802 | $ 8,275,375 |
| Payroll payables | 105,243 | 98,001 |
| | $ 10,949,045 | $ 8,373,376 |

## 15. Long-term debt

| | 2016 | 2015 |
|---|---|---|
| Demand note (a) | $ 10,000,000 | $ 10,000,000 |
| Shareholder notes (b) | 8,038,524 | 8,038,524 |
| Shareholder demand notes (c) | 2,083,391 | 2,083,391 |
| Finance lease obligation (d) | 811,488 | 289,759 |
| | 20,933,403 | 20,411,674 |
| Less: current portion | 192,612 | 108,049 |
| | $ 20,740,791 | $ 20,303,625 |

(a) Demand note

The Corporation has a demand promissory note payable to ERTH Corporation for $10,000,000 (2015 - $10,000,000) which bears interest at 7.25%. This note is unsecured. There are no fixed repayments terms associated with the principal outstanding and no principal is anticipated to be paid over the next thirteen months.

(b) Shareholder notes

The shareholder notes represents amounts owing to the municipal shareholders of ERTH Corporation for purchase of the respective Municipality's Hydro Electric Commission's net assets. The rate of interest is currently 7.25% and is set by the Board of Directors, from time to time. There are no fixed repayment terms associated with the principal outstanding and no principal is anticipated to be paid over the next thirteen months. The loan is secured by a second position General Security Agreement covering accounts receivable, inventory and equipment, including motor vehicles.

The amounts owing to the municipalities are as follows:

| | 2016 | 2015 |
|---|---|---|
| Aylmer | $ 1,694,863 | $ 1,694,863 |
| Central Elgin | 806,436 | 806,436 |
| East-Zorra Tavistock | 569,073 | 569,073 |
| Ingersoll | 3,402,080 | 3,402,080 |
| Norwich | 763,755 | 763,755 |
| South-west Oxford | 192,062 | 192,062 |
| Zorra | 610,255 | 610,255 |
| | $ 8,038,524 | $ 8,038,524 |

(c) Shareholder demand notes

The Corporation has a demand promissory note payable to the Municipality of West Perth for $900,000 (2015 - $ 900,000 ) which bears interest at 7.25% (2015 - 7%). Interest is payable in quarterly installments of $5,250. This note is unsecured. During the year, the terms were renegotiated such that there are no fixed repayment terms associated with the principal outstanding and no principal is anticipated to be paid over the next thirteen months.

The Corporation has a second demand promissory note payable to the Municipality of West Perth for $1,183,391 (2015 - $1,183,391) which bears interest at 7.25%. There are no fixed terms of repayment. This note is unsecured. During the year, the terms were renegotiated such that there are no fixed repayment terms associated with the principal outstanding and no principal is anticipated to be paid over the next thirteen months.

**15. Long-term debt (continued)**

(d) Finance lease obligations

| | Less than one year | Between one and five years | More than five years | Total |
|---|---|---|---|---|
| Future minimum lease payments | | | | |
| 2016 | $ 218,962 | $ 668,979 | $ - | $ 887,941 |
| 2015 | 121,872 | 190,628 | - | 312,500 |
| Interest | | | | |
| 2016 | $ 26,350 | $ 50,103 | $ - | $ 76,453 |
| 2015 | 13,823 | 8,918 | - | 22,741 |
| Present value of minimum lease payments | | | | |
| 2016 | $ 192,612 | $ 618,876 | $ - | $ 811,488 |
| 2015 | 108,049 | 181,710 | - | 289,759 |

**16. Post-employment benefits**

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2016, the Corporation made employer contributions of $403,239 to OMERS (2015 - $410,667).

As at December 31, 2016, OMERS had approximately 470,000 members, of whom 47 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2016, which reported that the plan was 93.4% funded, with an unfunded liability of $5.7 billion. This unfunded liability is likely to result in future payments by participating employers and members.

(b) Post-employment benefits other than pension

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expenses and remeasurements recognize for post-employment benefit plans.

Reconciliation of the obligation

| | **2016** | **2015** |
|---|---|---|
| Defined benefit obligation, beginning of year | $ 829,100 | $ 794,900 |
| Included in profit or loss | | |
| Current service cost | 27,100 | 26,100 |
| Interest cost | 32,600 | 31,300 |
| | 888,800 | 852,300 |
| Included in OCI | | |
| Actuarial gains arising from: | | |
| Changes in experience | (28,300) | (500) |
| Changes in demographic assumptions | (11,900) | - |
| Changes in financial assumptions | (27,600) | - |
| | 821,000 | 851,800 |
| Benefits paid | 23,900 | 22,700 |
| Defined benefit obligation, end of year | $ 797,100 | $ 829,100 |

## 16. Post-employment benefits (continued)

Actuarial assumptions

| | 2016 | 2015 |
|---|---|---|
| Discount rate | 4.00% | 4.00% |
| Salary levels | 2.00% | 2.50% |
| Medical costs | 7.00% | 8.00% |
| Dental costs | 4.00% | 4.50% |

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $144,400 decrease in the assumed discount rate would result in the defined benefits obligation increasing by $144,400.

## 17. Share capital

Authorized
Unlimited number of common shares

| | 2016 | 2015 |
|---|---|---|
| Issued capital | | |
| 10,000 Common shares | $ 10,855,585 | $ 10,855,585 |

(a) Dividends

The holders of the common shares are entitled to receive dividends as declared from time to time.

The Corporation paid aggregate dividends in the year on common shares of nil per share (2015 - $200), which amount to total dividends paid of nil during 2016 (2015 - $2,000,000).

## 18. Other revenue

| | 2016 | 2015 |
|---|---|---|
| Service | $ 504,862 | $ 454,037 |
| Contributions received from customers | 28,635 | 19,080 |
| | $ 533,497 | $ 473,117 |

## 19. Employee salaries and benefits

| | 2016 | 2015 |
|---|---|---|
| Salaries, wages and benefits | $ 2,566,071 | $ 2,727,121 |
| CPP and EI remittances | 177,206 | 166,034 |
| Contributions to OMERS | 403,239 | 410,667 |
| Post-employment benefit plans | 35,800 | 34,700 |
| | $ 3,182,316 | $ 3,338,522 |

The presentation of the comparative amounts has been reclassified to conform with the current year presentation which resulted in an increase of $132,777 to salaries, wages and benefits and a respective decrease to operating expenses.

**20. Operating expenses**

| | 2016 | 2015 |
|---|---|---|
| Contracting and consulting | $ 425,567 | $ 245,273 |
| Materials and supplies | 712,397 | 780,105 |
| Vehicle recovery | (141,306) | (190,810) |
| Billing and collecting | 706,184 | 822,342 |
| Office administration | 1,283,773 | 954,063 |
| Community relations | 150,231 | 131,404 |
| Loss (gain) on sale of equipment | (61,534) | 20,829 |
| Other | 82,737 | 89,685 |
| | $ 3,158,049 | $ 2,852,891 |

The presentation of the comparative amounts has been reclassified to conform with the current year presentation which resulted in a decrease of $65,586 to contracting and consulting, $521,151 to vehicles, $9,321 to office administration and an increase of $331,376 to materials and supplies, $131,404 to community relations and $132,777 to employee, wages and benefits.

**21. Finance costs**

| | 2016 | 2015 |
|---|---|---|
| Finance costs | | |
| Interest expense on long-term debt | 758,000 | 554,732 |
| Shareholder interest | 733,276 | 733,276 |
| Interest expense on customer deposits | (15,599) | 1,821 |
| Overdraft and other bank charges | 83,696 | 30,899 |
| Finance costs recognized in profit or loss | $ 1,559,373 | $ 1,320,728 |

The presentation of the comparative amounts has been reclassified to conform with the current year presentation which resulted in a $20,673 movement from interest expense on long-term debt to overdraft and other bank charges.

**22. Customer deposits**

The presentation of the comparative amounts has been reclassified to account for commercial deposits which can be held for up to seven years for customers with a good payment history as well as customer deposits which are not anticipated to be refunded in the next twelve months.

**23. Commitments and contingencies**

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2016, no assessments have been made.

## 24. Guarantee

The Corporation has guaranteed the operating and term loans of its parent Company ERTH Corporation up to 25% of the Corporations equity or $3,386,272. The loans are secured by a General Security Agreement covering all assets of the Corporation and a pledge of the shares of the Corporation. As the Corporation does not expect to be in a position where it would need to honour this guarantee in the foreseeable future, no liability has been recorded in these financial statements.

## 25. Operating leases

The Corporation is committed to lease agreements for various vehicles and equipment.

The future minimum non-cancelable annual lease payments are as follows:

| | 2016 | 2015 |
|---|---|---|
| Less than one year | $ 59,686 | $ 43,629 |
| Between one and five years | 70,299 | 25,480 |
| More than five years | - | - |
| | $ 129,985 | $ 69,109 |

During the year ended December 31, 2016 an expense of $73,285 (2015 - $59,833) was recognized in operating expenses in the statement of comprehensive income in respect of operating leases.

## 26. Related party transactions

(a) Shareholders and ultimate controlling party

The sole shareholder of the Corporation is ERTH Corporation, which in turn is wholly-owned by eight municipalities Alymer, Central Elgin, East-Zorra-Tavistock, Ingersoll, Norwich, South-West Oxford, Zorra and West Perth.

(b) Companies under common control

ERTH Corporation owns 100% of the issued and outstanding shares of ERTH Limited.

ERTH Business Technologies Inc., ERTH (Holdings) Inc. and J-Mar Line Maintenance Inc. are wholly-owned subsidiaries of ERTH Limited.

(c) Outstanding balances with related parties

The following represent due from/to in the normal course of operations:

| | 2016 | 2015 |
|---|---|---|
| Due from: | | |
| ERTH Corporation | $ 30,381 | $ 25,484 |
| ERTH (Holdings) Inc. | 44,164 | 71,544 |
| ERTH Business Technologies Inc. | 2,320 | 129 |
| J-Mar Line Maintenance Inc. | 64,948 | - |
| | $ 141,813 | $ 97,157 |

| | 2016 | 2015 |
|---|---|---|
| Due to: | | |
| ERTH Corporation | $ 52,446 | $ 588,753 |
| ERTH (Holdings) Inc | 78,742 | 96,105 |
| Town of Aylmer | 219,890 | 218,263 |
| | $ 351,078 | $ 903,121 |

**26. Related party transactions (continued)**

(c) Outstanding balances with related parties

The transactions between the Corporation and its related parties are measured at the exchange amount, which is the amount of consideration paid or received as established and agreed to by the related parties, unless otherwise noted.

The Corporation has contracted ERTH (Holdings) Inc. and ERTH Business Technologies Inc., to provide maintenance and upgrades to the existing capital infrastructure of the Corporation and administrative services.

(d) Transactions with parent

The Corporation has a contract with ERTH Corporation, the parent company, for management services and rental of facilities used by the Corporation.

During the year, the Corporation paid management services, consulting services and rental fees to its parent in the amount of $1,078,000, $200,000 and $210,500 respectively (2015 - $1,032,069, $222,281 and $212,820). The Corporation also charged its parent company $155,040 (2015 - $108,721) for operations and administrative services.

(e) Transactions with companies under common control

During the year, the Corporation had the following transactions with related parties as follows:

- sold operations and administration services of $2,768 (2015 - nil) to ERTH Business Technologies Inc.

- purchased capitalized items of $64,901 (2015 - $12,465) and operations, administration services of $2,642 (2015 - nil), sold operations, administration services of $7,032 (2015 - nil) and sold capital equipment of $29,589 (2015 – $12,000) to J-Mar Line Maintenance Inc.

- purchased capitalized items of $275,405 (2015 - $65,733), operations, maintenance and administration services of $800,011 (2015 - $524,710), sold operations, maintenance and admission services of $438,576 (2015 - $327,766) and sold capital assets of nil (2015 - $5,000) to ERTH (Holdings) Inc.

In the ordinary course of business, the Corporation delivers electricity to ERTH (Holdings) Inc. Electricity is billed to ERTH (Holdings) Inc. at prices and under terms approved by the OEB, if applicable.

(f) Transactions with ultimate parents

The Corporation delivers electricity to the eight municipalities throughout the year for the electricity needs of the municipalities and their related organizations. Electricity delivery charges are at prices under terms approved by the OEB. The Corporation also provides additional services to the Municipality or Norwich, the Town of Aylmer and the Town of Ingersoll for water and waste water billing and customer care services.

The Municipality of West Perth charges the Corporation for tree trimming and annual rent.

**27. Financial instruments and risk management**

Fair value disclosure

The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, due from/to related parties and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the long-term debt at December 31, 2016 is $19,248,053 (2015 - $19,248,053). The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rate used to calculate fair value at December 31, 2016 was 4.54% (2015 - 4.54%).

The fair value of available for sale financial assets is based on the closing value of the equity in the publicly traded markets.

Financial risks

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the municipalities of Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford, Zorra and West Perth. As a result, the Corporation did not earn a significant amount of revenue from any one individual customer.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the allowance for impairment at December 31, 2016 is $837,820 (2015 - $804,806). An impairment loss of $26,204 (2015 - $87,793) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2016, approximately $181,221 (2015 - $174,806) is considered 60 days past due. The Corporation has over 18,000 customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2016, the Corporation holds security deposits in the amount of $952,081 (2015 - $760,379).

**27. Financial instruments and risk management (continued)**

(b) Market risk

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

The Corporation minimizes interest rate risk by issuing long-term fixed rate debt.

(c) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $37 million credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2016, $31 million has been drawn under the Corporation's credit facility.

The Corporation also has a bilateral facility for $2.3 million for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $2,246,667 has been drawn and posted with the IESO (2015 - $2,246,667).

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days.

(d) Capital disclosures

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2016, shareholder's equity amounts to $14,626,592 (2015 - $13,545,089) and long-term debt amounts to $10,740,791 (2015- $10,303,625).

# ATTACHMENT 8

# FINANCIAL STATEMENTS – ERIE THAMES POWERLINES - 2015

Financial Statements of

# ERIE THAMES POWERLINES CORPORATION

Years ended December 31, 2015 and 2014

**KPMG LLP**
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Canada

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# INDEPENDENT AUDITORS' REPORT

To the Shareholder of Erie Thames Powerlines Corporation

We have audited the accompanying financial statements of Erie Thames Powerlines Corporation (the “Entity”), which comprise the statements of financial position as at December 31, 2015, December 31, 2014 and January 1, 2014, the statements of comprehensive income, changes in equity and cash flows for the years ended December 31, 2015, and December 31, 2014, and notes, comprising a summary of significant accounting policies and other explanatory information.

*Management’s Responsibility for the Financial Statements*

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

*Auditors’ Responsibility*

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity’s preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity’s internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

*Opinion*

In our opinion, the financial statements present fairly, in all material respects, the financial position of Erie Thames Powerlines Corporation as at December 31, 2015, December 31, 2014 and January 1, 2014, and its financial performance and its cash flows for the years ended December 31, 2015, and December 31, 2014 in accordance with International Financial Reporting Standards**.**

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
April 28, 2016
London, Canada

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative (”KPMG International”), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

# ERIE THAMES POWERLINES CORPORATION

Statements of Financial Position

| | Note | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|---|
| **Assets** | | | | |
| **Current assets** | | | | |
| Accounts receivable | 5 | $ 4,852,917 | $ 5,056,532 | $ 7,928,600 |
| Materials and supplies | 6 | 86,525 | 169,979 | 96,769 |
| Due from related parties | 24 | 97,157 | 48,371 | 47,387 |
| Unbilled revenue | | 5,616,740 | 4,959,235 | 4,376,148 |
| Payments in lieu of income taxes receivable | | 204,555 | --- | 190 |
| Prepaid expenses | | 82,070 | 112,967 | 122,226 |
| Total current assets | | 10,939,964 | 10,347,084 | 12,571,320 |
| **Non-current assets** | | | | |
| Property, plant and equipment | 8 | 34,079,941 | 30,497,189 | 28,066,972 |
| Intangible assets | 9 | 597,851 | 553,077 | 523,138 |
| Investment | 7 | 21,415 | 20,805 | 18,621 |
| Deferred tax assets | 10 | 37,000 | 273,000 | 423,000 |
| Total non-current assets | | 34,736,207 | 31,344,071 | 29,031,731 |
| **Total assets** | | 45,676,171 | 41,691,155 | 41,603,051 |
| Regulatory balances | 11 | 6,154,937 | 4,986,417 | 3,638,451 |
| **Total assets and regulatory balances** | | $ 51,831,108 | $ 46,677,572 | $ 45,241,502 |

See accompanying notes to the financial statements.

# ERIE THAMES POWERLINES CORPORATION

Statements of Financial Position

| | Note | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|---|
| **Liabilities** | | | | |
| **Current liabilities** | | | | |
| Bank overdraft | 12 | $ 1,695,391 | $ 5,411,329 | $ 6,033,352 |
| Accounts payable and accrued liabilities | 13 | 8,373,377 | 9,353,321 | 7,605,745 |
| Due to related parties | 24 | 903,121 | 937,287 | 642,810 |
| Payments in lieu of income taxes payable | | --- | 165,695 | --- |
| Long-term debt due within one year | 14 | 108,049 | 2,199,211 | 2,192,675 |
| Customer deposits | | 760,379 | 752,557 | 658,585 |
| Deferred revenue | | 472,282 | 347,415 | 246,707 |
| Total current liabilities | | 12,312,599 | 19,166,815 | 17,379,874 |
| **Non-current liabilities** | | | | |
| Long-term debt | 14 | 20,303,625 | 8,328,059 | 8,444,418 |
| Post-employment benefits | 15 | 829,100 | 794,900 | 650,200 |
| Deferred revenue | | 1,315,009 | 677,498 | --- |
| Total non-current liabilities | | 22,447,734 | 9,800,457 | 9,094,618 |
| **Total liabilities** | | 34,760,333 | 28,967,272 | 26,474,492 |
| **Equity** | | | | |
| Share capital | 16 | 10,855,585 | 10,855,585 | 10,855,585 |
| Retained earnings | | 2,800,310 | 3,846,506 | 2,647,986 |
| Accumulated other comprehensive loss | | (110,806) | (111,916) | --- |
| **Total equity** | | 13,545,089 | 14,590,175 | 13,503,571 |
| **Total liabilities and equity** | | 48,305,422 | 43,557,447 | 39,977,873 |
| Regulatory balances | 11 | 3,525,686 | 3,120,125 | 5,263,439 |
| **Total liabilities, equity and regulatory balances** | | $ 51,831,108 | $ 46,677,572 | $ 45,241,502 |

Commitments and contingencies (note 21).

Guarantees (note 22).

See accompanying notes to the financial statements.

On behalf of the Board:

[redacted] Director

[redacted] Director

# ERIE THAMES POWERLINES CORPORATION

Statements of Comprehensive Income
Year ended December 31, 2015, with comparative information for 2014

| | Note | 2015 | 2014 |
|---|---|---|---|
| **Revenue** | | | |
| Sale of energy | | $ 53,673,716 | $ 47,432,029 |
| Distribution revenue | | 9,790,667 | 9,620,820 |
| Other | 17 | 473,117 | 456,919 |
| | | 63,937,500 | 57,509,768 |
| **Operating expenses** | | | |
| Cost of power purchased | | 54,426,015 | 50,909,215 |
| Employee salaries and benefits | 18 | 3,205,747 | 3,116,586 |
| Operating expenses | 19 | 2,985,667 | 2,569,402 |
| Depreciation and amortization | | 1,544,499 | 1,474,236 |
| | | 62,161,928 | 58,069,439 |
| **Income from operating activities** | | 1,775,573 | (559,671) |
| Finance income | 20 | --- | 22,712 |
| Finance costs | 20 | 1,320,728 | 1,389,801 |
| **Income before income taxes** | | 454,845 | (1,926,760) |
| Income tax expense | 10 | 264,000 | 397,000 |
| **Net income for the year** | | **190,845** | **(2,323,760)** |
| Net movement in regulatory balances, net of tax | 11 | 762,959 | 3,522,280 |
| **Net income for the year and net movement in regulatory balances** | | **953,804** | **1,198,520** |
| **Other comprehensive income** | | | |
| Items that will be reclassified to profit or loss: | | | |
| Change in fair value of investments | | 610 | 2,184 |
| Items that will not be reclassified to profit or loss: | | | |
| Remeasurements of post-employment benefits | 15 | 500 | (114,100) |
| Tax on remeasurements | 10 | --- | 31,000 |
| Net movement in regulatory balances, net of tax | 11 | --- | (31,000) |
| **Other comprehensive income for the year** | | 1,110 | (111,916) |
| **Total comprehensive income for the year** | | $ 954,914 | $ 1,086,604 |

See accompanying notes to the financial statements.

# ERIE THAMES POWERLINES CORPORATION

Statements of Changes in Equity
Year ended December 31, 2015, with comparative information for 2014

| | Share capital | Retained earnings | Accumulated other comprehensive income (loss) | Total |
|---|---|---|---|---|
| **Balance at January 1, 2014** | $10,855,585 | $2,647,986 | $ --- | $13,503,571 |
| Net income and net movement in regulatory balances | --- | 1,198,520 | --- | 1,198,520 |
| Other comprehensive loss | --- | --- | (111,916) | (111,916) |
| **Balance at December 31, 2014** | $10,855,585 | $3,846,506 | $(111,916) | $14,590,175 |
| **Balance at January 1, 2015** | $10,855,585 | $3,846,506 | $(111,916) | $14,590,175 |
| Net income and net movement in regulatory balances | --- | 953,804 | --- | 953,804 |
| Other comprehensive income | --- | --- | 1,110 | 1,110 |
| Dividends | --- | (2,000,000) | --- | (2,000,000) |
| **Balance at December 31, 2015** | $10,855,585 | $2,800,310 | $(110,806) | $13,545,089 |

See accompanying notes to the financial statements.

# ERIE THAMES POWERLINES CORPORATION

Statements of Cash Flows
Year ended December 31, 2015, with comparative information for 2014

| | 2015 | 2014 |
|---|---|---|
| **Operating activities** | | |
| Net Income and net movement in regulatory balances | $ 953,804 | $ 1,198,520 |
| Adjustments for: | | |
| Depreciation and amortization | 1,544,499 | 1,474,236 |
| Amortization of deferred revenue | (19,080) | (6,758) |
| Post-employment benefits | 34,700 | 30,600 |
| Losses on disposal of property, plant and equipment | 20,829 | 9,843 |
| Net finance costs | 1,320,728 | 1,367,089 |
| Income tax expense | 264,000 | 397,000 |
| | 4,119,480 | 4,470,530 |
| Change in non-cash operating working capital: | | |
| Accounts receivable | 203,616 | 2,872,068 |
| Due to/from related parties | (82,952) | 293,493 |
| Unbilled revenue | (657,507) | (583,086) |
| Materials and supplies | 83,454 | (73,210) |
| Prepaid expenses | 30,897 | 9,259 |
| Accounts payable and accrued liabilities | (979,944) | 1,747,576 |
| Customer deposits | 7,822 | 93,972 |
| | (1,394,614) | 4,360,262 |
| Regulatory balances | (762,959) | (3,522,280) |
| Income tax paid | (398,250) | (50,305) |
| **Net cash from operating activities** | 1,563,657 | 5,258,207 |
| **Investing activities** | | |
| Purchase of property, plant and equipment | (5,046,075) | (3,828,618) |
| Proceeds on disposal of property, plant and equipment | 21,583 | 21,939 |
| Purchase of intangible assets | (168,361) | (137,557) |
| Contributions received from customers | 781,458 | 784,964 |
| **Net cash used by investing activities** | (4,411,395) | (3,159,272) |
| **Financing activities** | | |
| Dividends paid | (2,000,000) | --- |
| Interest paid | (1,320,728) | (1,389,801) |
| Interest received | --- | 22,712 |
| Proceeds from long-term debt | 10,000,000 | --- |
| Repayment of long-term debt | (115,596) | (109,823) |
| **Net cash from financing activities** | 6,563,676 | (1,476,912) |
| Change in bank indebtedness | 3,715,938 | 622,023 |
| Bank indebtedness, beginning of year | (5,411,329) | (6,033,352) |
| **Bank indebtedness, end of year** | $ (1,695,391) | $ (5,411,329) |

See accompanying notes to the financial statements.

## 1. Reporting entity

Erie Thames Powerlines Corporation (the “Corporation”) is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the Town of Ingersoll. The address of the Corporation’s registered office is 143 Bell Street, PO Box 157 Ingersoll ON (Canada) N5C 3K5.

The Corporation delivers electricity and related energy services to residential and commercial customers in Aylmer, Beachville, Belmont, Burgessville, Embro, Ingersoll, Norwich, Otterville, Port Stanley, Tavistock, Thamesford, Clinton, Mitchell and Dublin. The Corporation is wholly owned by ERTH Corporation who is wholly owned by the following eight municipalities, each of whom has one voting common share: Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford, Zorra and West Perth.

The financial statements are for the Corporation as at and for the year ended December 31, 2015.

## 2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

(b) Adoption of IFRS

These are the Corporation’s first financial statements prepared in accordance with IFRS and IFRS 1 *First-time Adoption of International Financial Reporting Standards* has been applied. An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Corporation is provided in note 26.

The financial statements were approved by the Board of Directors on April 28, 2016.

(c) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(d) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest dollar.

**2. Basis of presentation (continued)**

(e) Use of estimates and judgments

(i) Assumptions and estimation uncertainty

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Note 3(b) – measurement of unbilled revenue
(ii) Notes 8, 9 – estimation of useful lives of its property, plant and equipment and intangible assets
(iii) Note 11 – recognition and measurement of regulatory balances
(iv) Note 15 – measurement of defined benefit obligations: key actuarial assumptions
(v) Note 21 – recognition and measurement of provisions and contingencies

(ii) Judgements

Information about judgements made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following notes:

(i) Note 8 – leases: whether an arrangement contains a lease

(f) Rate regulation

The Corporation is regulated by the Ontario Energy Board (“OEB”), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies (“LDCs”), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The Corporation is required to bill customers for the debt retirement charge set by the province. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation (“OEFC”) once each year.

**2. Basis of presentation (continued)**

(f) Rate regulation (continued)

Rate setting

*Distribution revenue*

For the distribution revenue included in sale of energy, the Corporation files a “Cost of Service” (“COS”) rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder’s equity required to support the Corporation’s business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application (“IRM”) is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year’s rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand (“GDP IPI-FDD”) net of a productivity factor and a “stretch factor” determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application on June 26, 2012 for rates effective January 1, 2013 to April 30, 2013. On September 26, 2014 an IRM application was filed with the OEB for rates effective May 1, 2015 until April 30, 2016. Within this application the approved GDP IPI-FDD is 1.60%, the Corporation’s productivity factor is 0.00% and the stretch factor is 0.30%, resulting in a net increase of 1.30% to the previous year’s rates.

*Electricity rates*

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

## 3. Significant accounting policies

The accounting policies set out below have been applied consistently in all years presented in these financial statements and in preparing the opening IFRS statement of financial position at January 1, 2014 for the purpose of the transition to IFRS.

(a) Financial instruments

All financial assets are classified as loans and receivables, except for investments which are classified as available for sale, and all financial liabilities are classified as other liabilities. These financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(f). Available for sale assets are subsequently measured at their fair value, with changes in fair value recognized in other comprehensive income until the asset is sold.

The Corporation does not enter into derivative instruments. Hedge accounting has not been used in the preparation of these financial statements.

(b) Revenue recognition

*Sale and distribution of electricity*

Revenue from the sale and distribution of electricity is recognized as the electricity is delivered to customers on the basis of cyclical meter readings and estimated customer usage since the last meter reading date to the end of the year. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

*Other revenue*

Revenue earned from the provision of services is recognized as the service is rendered.

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. Cash contributions are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Government grants and the related performance incentive payments under CDM programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

**3. Significant accounting policies (continued)**

(c) Materials and supplies

Materials and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

(d) Property, plant and equipment

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date (see note 26(a)), less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

**3. Significant accounting policies (continued)**

(d) Property, plant and equipment (continued)

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

| | Years |
|---|---|
| Buildings | 55 - 60 |
| Automotive equipment | 8 - 10 |
| Computer equipment | 5 - 15 |
| Services, office and other equipment | 5 - 8 |
| Transmission and distribution system | 12 - 60 |

(e) Intangible assets

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date (see note 26(a)), less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

Goodwill represents the excess of cost over fair value of net assets of businesses acquired. Goodwill is measured at cost less accumulated impairment losses.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

| | Years |
|---|---|
| Computer software | 5 - 10 |
| Land rights | indefinite life |
| Goodwill | indefinite life |

**3. Significant accounting policies (continued)**

(f) Impairment

(i) Financial assets measured at amortized cost

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss is calculated as the difference between an asset's carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorate basis, if applicable.

An impairment loss in respect of goodwill is not reversed. For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

**3. Significant accounting policies (continued)**

(g) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(i) Regulatory balances

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

**3. Significant accounting policies (continued)**

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Remeasurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(k) Leased assets

Leases, where the terms cause the Corporation to assume substantially all the risks and rewards of ownership, are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

All other leases are classified as operating leases and the leased assets are not recognized on the Corporation's statement of financial position. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease.

**3. Significant accounting policies (continued)**

(l) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents and dividend income.

Finance costs comprise interest expense on borrowings, finance lease obligations and unwinding of the discount on provisions and impairment losses on financial assets. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(m) Income taxes

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

**4. Standards issued but not yet adopted**

*Future accounting changes*

There are new standards, amendments to standards and interpretations which have not been applied in preparing these financial statements.

a) *Annual Improvements to IFRS (2012-2014) cycle.* On September 25, 2014 the IASB issued narrow-scope amendments to a total of four standards as part of its annual improvements process. The amendments will apply for annual periods beginning on or after January 1, 2016. Earlier application is permitted, in which case, the related consequential amendments to other IFRSs would also apply. Each of the amendments has its own specific transition requirements.

   Amendments were made to clarify the following in their respective standards:

   - Changes in method for disposal under IFRS 5 Non-current Assets Held for Sale and Discontinued Operations;
   - 'Continuing involvement' for servicing contracts and offsetting disclosures in condensed interim financial statements under IFRS 7 Financial Instruments: Disclosures;
   - Discount rate in a regional market sharing the same currency under IAS 19 Employee Benefits;
   - Disclosure of information 'elsewhere in the interim financial report' under IAS 34 Interim Financial Reporting;

   The Corporation intends to adopt these amendments in its financial statements for the annual period beginning on January 1, 2016. The Corporation does not expect the amendments to have a material impact on the financial statements.

b) *Disclosure Initiative: Amendments to IAS 1*. On December 18, 2014 the IASB issued amendments to IAS 1 Presentation of Financial Statements as part of its major initiative to improve presentation and disclosure in financial reports (the "Disclosure Initiative"). The amendments are effective for annual periods beginning on or after 1 January 2016. Early adoption is permitted.

   These amendments will not require any significant change to current practice, but should facilitate improved financial statement disclosures.

   The Corporation intends to adopt these amendments in its financial statements for the annual period beginning on January 1, 2016. The extent of the impact of adoption of the amendments has not yet been determined.

**4. Standards issued but not yet adopted (continued)**

c) On May 28, 2014 the IASB issued *IFRS 15 Revenue from Contracts with Customers*. The new standard is effective for annual periods beginning on or after January 1, 2018. Earlier application is permitted. IFRS 15 will replace IAS 11 Construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programs, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfer of Assets from Customers, and SIC 31 Revenue – Barter Transactions Involving Advertising Services.

The standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized.

The new standard applies to contracts with customers. It does not apply to insurance contracts, financial instruments or lease contracts, which fall in the scope of other IFRSs.

The Corporation intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of adoption of the standard has not yet been determined.

d) On July 24, 2014 the IASB issued the complete *IFRS 9 (IFRS 9 (2014))*. The mandatory effective date of IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted. The restatement of prior periods is not required and is only permitted if information is available without the use of hindsight.

IFRS 9 (2014) introduces new requirements for the classification and measurement of financial assets. Under IFRS 9 (2014), financial assets are classified and measured based on the business model in which they are held and the characteristics of their contractual cash flows.

The standard introduces additional changes relating to financial liabilities.

It also amends the impairment model by introducing a new 'expected credit loss' model for calculating impairment.

IFRS 9 (2014) also includes a new general hedge accounting standard which aligns hedge accounting more closely with risk management. This new standard does not fundamentally change the types of hedging relationships or the requirement to measure and recognize ineffectiveness, however it will provide more hedging strategies that are used for risk management to qualify for hedge accounting and introduce more judgment to assess the effectiveness of a hedging relationship.

Special transitional requirements have been set for the application of the new general hedging model.

The Corporation intends to adopt IFRS 9 (2014) in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of adoption of the standard has not yet been determined.

## 4. Standards issued but not yet adopted (continued)

e) On January 13, 2016 the IASB issued *IFRS 16 Leases*. The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 Revenue from Contracts with Customers at or before the date of initial adoption of IFRS 16. IFRS 16 will replace IAS 17 Leases.

This standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments.

This standard substantially carries forward the lessor accounting requirements of IAS 17, while requiring enhanced disclosures to be provided by lessors.

Other areas of the lease accounting model have been impacted, including the definition of a lease. Transitional provisions have been provided.

The Corporation intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The extent of the impact of adoption of the standard has not yet been determined.

All of the above standards or amendments relate to the measurement and disclosure of financial assets and liabilities. The extent of the impact on adoption of these standards and amendments has not yet been determined.

## 5. Accounts receivable

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Trade receivables | $3,807,167 | $ 3,708,422 | $ 6,959,489 |
| Billable work | 1,045,750 | 1,348,110 | 969,111 |
| | $4,852,917 | $ 5,056,532 | $ 7,928,600 |

## 6. Materials and supplies

Amount written down due to obsolescence in 2015 was nil (2014 - nil).

## 7. Investment

The Corporation holds 386 Common shares of Sunlife Financial with a fair value of $21,415 at December 31, 2015 (2014 - $20,805).

## 8. Property, plant and equipment

| | Land and buildings | Distribution equipment | Other fixed assets | Construction -in-Progress | Total |
|---|---|---|---|---|---|
| *Cost or deemed cost* | | | | | |
| Balance at January 1, 2015 | $ 220,945 | $28,712,833 | $ 2,077,928 | $ 701,998 | $ 31,713,704 |
| Additions | --- | 3,940,591 | 608,981 | 1,198,503 | 5,748,075 |
| Transfers | --- | --- | --- | (701,998) | (701,998) |
| Disposals/retirements | --- | (263,376) | (125,328) | --- | (388,704) |
| Balance at December 31, 2015 | $ 220,945 | $32,390,048 | $ 2,561,581 | $1,198,503 | $ 36,371,077 |
| Balance at January 1, 2014 | $ 220,945 | $24,492,643 | $1,871,907 | $1,481,477 | $ 28,066,972 |
| Additions | --- | 4,359,633 | 248,463 | 701,998 | 5,310,094 |
| Transfers | --- | --- | --- | (1,481,477) | (1,481,477) |
| Disposals/retirements | --- | (139,443) | (42,442) | --- | (181,885) |
| Balance at December 31, 2014 | $ 220,945 | $28,712,833 | $2,077,928 | $ 701,998 | $ 31,713,704 |
| *Accumulated depreciation* | | | | | |
| Balance at January 1, 2015 | $ 3,260 | $ 934,267 | $278,988 | $ --- | $ 1,216,515 |
| Depreciation | 3,260 | 1,147,220 | 270,432 | --- | 1,420,912 |
| Disposals/retirements | --- | (220,964) | (125,327) | --- | (346,291) |
| Balance at December 31, 2015 | $ 6,520 | $1,860,523 | $424,093 | $ --- | $ 2,291,136 |
| Balance at January 1, 2014 | $ --- | $ --- | $ --- | $ --- | $ --- |
| Depreciation | 3,260 | 1,056,064 | 307,294 | --- | 1,366,618 |
| Disposals/retirements | --- | (121,797) | (28,306) | --- | (150,103) |
| Balance at December 31, 2014 | $ 3,260 | $ 934,267 | $278,988 | $ --- | $ 1,216,515 |
| *Carrying amounts* | | | | | |
| At December 31, 2015 | $ 214,424 | $30,529,524 | $2,137,488 | $1,198,503 | $ 34,079,941 |
| At December 31, 2014 | 217,685 | 27,778,566 | 1,798,940 | 701,998 | 30,497,189 |
| At January 1, 2014 | 220,945 | 24,492,643 | 1,871,907 | 1,481,477 | 28,066,972 |

The Corporation leases equipment under a number of finance lease agreements. The leased equipment secures the lease obligations (see note 14). At December 31, 2015 the net carrying amount of leased equipment was $469,934 thousand (2014 - $457,415).

During the year, borrowing costs of nil (2014 - nil) were capitalized as part of the cost of property, plant and equipment.

PP&E and intangible asset purchase commitments outstanding as at December 31, 2015 was $335,995 (2014 - $379,574).

## 9. Intangible assets

| | Computer software | Land rights | Goodwill | Total |
|---|---|---|---|---|
| *Cost or deemed cost* | | | | |
| Balance at January 1, 2015 | $ 540,150 | $ 43,879 | $ 76,667 | $ 660,696 |
| Additions | 168,360 | --- | --- | 168,360 |
| Balance at December 31, 2015 | $ 708,510 | $ 43,879 | $ 76,667 | $ 829,056 |
| Balance at January 1, 2014 | $ 402,592 | $ 43,879 | $ 76,667 | $ 523,138 |
| Additions | 137,558 | --- | --- | 137,558 |
| Balance at December 31, 2014 | $ 540,150 | $ 43,879 | $ 76,667 | $ 660,696 |
| *Accumulated depreciation* | | | | |
| Balance at January 1, 2015 | $ 107,619 | $ --- | $ --- | $ 107,619 |
| Depreciation | 123,587 | --- | --- | 123,587 |
| Balance at December 31, 2015 | $ 231,206 | $ --- | $ --- | $ 231,206 |
| Balance at January 1, 2014 | $ --- | $ --- | $ --- | $ --- |
| Depreciation | 107,619 | --- | --- | 107,619 |
| Balance at December 31, 2014 | $ 107,619 | $ --- | $ --- | $ 107,619 |
| *Carrying amounts* | | | | |
| At December 31, 2015 | $ 477,305 | $ 43,879 | $ 76,667 | $ 597,851 |
| At December 31, 2014 | 432,531 | 43,879 | 76,667 | 553,077 |
| At January 1, 2014 | 402,592 | 43,879 | 76,667 | 523,138 |

## 10. Income tax expense

Income tax expense

| | 2015 | 2014 |
|---|---|---|
| Current tax | $ 28,000 | $ 216,000 |
| Deferred tax expense | 236,000 | 181,000 |
| | 264,000 | 397,000 |
| Other comprehensive income: | | |
| Post-employment benefits | --- | (31,000) |
| | 264,000 | 366,000 |
| Net movement in regularity balances | (236,000) | (150,000) |
| | $ 28,000 | $ 216,000 |

**10. Income tax expense (continued)**

Reconciliation of effective tax rate

| | 2015 | 2014 |
|---|---|---|
| Income before taxes | $ 982,914 | $ 1,302,604 |
| Canada and Ontario statutory Income tax rates | 26.5% | 26.5% |
| Expected tax provision on income at statutory rates | 260,000 | 345,000 |
| Increase (decrease) in income taxes resulting from: | | |
| Permanent differences | 3,000 | 2,000 |
| Recognized deductible temporary differences due to/from customers | (236,000) | (150,000) |
| Other | 1,000 | 19,000 |
| Income tax expense | $ 28,000 | $ 216,000 |

Significant components of the Corporation's deferred tax balances

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Deferred tax assets (liabilities): | | | |
| Property, plant and equipment | $ (209,000) | $ 30,000 | $ 195,000 |
| Cumulative eligible capital | 47,000 | 51,000 | 56,000 |
| Post-employment benefits | 220,000 | 211,000 | 172,000 |
| Deferred revenue | (21,000) | (19,000) | --- |
| | $ 37,000 | $ 273,000 | $ 423,000 |

## 11. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances

| Regulatory deferral account debit balances | January 1, 2015 | Additions | Recovery/ reversal | December 31, 2015 | Remaining recovery/ reversal years |
|---|---|---|---|---|---|
| Regulatory settlement account | $4,788,507 | $(1,751,904) | $ 2,222,303 | $5,258,906 | 2 |
| PILS regulatory adjustment | 118,153 | --- | 189,891 | 308,044 | 2 |
| Regulatory assets account | 55,988 | 1,388,982 | (1,005,719) | 439,251 | 2 |
| Smart meters | 13,728 | (11,744) | (5,407) | (3,423) | 2 |
| Stranded meters | 9,810 | --- | (37) | 9,773 | 2 |
| LRAM | --- | 185,977 | (99,811) | 86,166 | 2 |
| Other regulatory accounts | 231 | 55,989 | (---) | 56,220 | 2 |
| | $4,986,417 | $ (132,700) | $ 1,301,220 | $6,154,937 | |

| Regulatory deferral account debit balances | January 1, 2014 | Additions | Recovery/ reversal | December 31, 2014 | Remaining years |
|---|---|---|---|---|---|
| Regulatory settlement account | $2,300,955 | $2,487,552 | $ (---) | $4,788,507 | 2 |
| PILS regulatory adjustment | --- | 118,153 | (---) | 118,153 | 2 |
| Regulatory assets account | 7,891 | 48,097 | (---) | 55,988 | 2 |
| Smart meters | 75,511 | --- | (61,783) | 13,728 | 2 |
| Stranded meters | 414,505 | --- | (404,695) | 9,810 | 2 |
| Other regulatory accounts | 839,589 | (839,358) | (---) | 231 | 2 |
| | $3,638,451 | $1,814,444 | $(466,478) | $4,986,417 | --- |

| Regulatory deferral account credit balances | January 1, 2015 | Additions | Recovery/ reversal | December 31, 2015 | Remaining years |
|---|---|---|---|---|---|
| Regulatory settlement account | $1,852,982 | $(1,893,434) | $2,221,496 | $2,181,044 | 2 |
| Regulatory liability account | 122,799 | --- | 208,728 | 331,527 | 2 |
| MIFRS regulatory adjustments | 758,465 | 204,354 | (---) | 962,819 | 2 |
| LRAM disposition | 67,181 | --- | (67,181) | --- | 2 |
| Other regulatory accounts | 45,698 | --- | (32,402) | 13,296 | --- |
| Deferred income tax | 273,000 | --- | (236,000) | 37,000 | --- |
| | $3,120,125 | $(1,689,080) | $2,094,641 | $3,525,686 | |

| Regulatory deferral account credit balances | January 1, 2014 | Additions | Recovery/ reversal | December 31, 2014 | Remaining years |
|---|---|---|---|---|---|
| Regulatory settlement account | $3,818,342 | $ --- | $(1,965,360) | $1,852,982 | 2 |
| Regulatory liability account | --- | 122,799 | (---) | 122,799 | 2 |
| MIFRS regulatory adjustments | 611,253 | 147,212 | (---) | 758,465 | 2 |
| LRAM disposition | | 67,181 | (---) | 67,181 | 2 |
| Other regulatory accounts | 410,844 | 27,000 | (392,146) | 45,698 | --- |
| Deferred income tax | 423,000 | --- | (150,000) | 273,000 | --- |
| | $5,263,439 | $ 364,192 | $(2,507,506) | $3,120,125 | --- |

## 11. Regulatory balances (continued)

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

Settlement of the Group 1 deferral accounts is done on an annual basis through application to the OEB. An application has been made to the OEB to recover $3,121,073 of the Group 1 deferral accounts. Approval is pending. Once approval is received, the approved account balance is moved to the regulatory settlement account. The balance is to be recovered over a period of two years. The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points. In 2015 the rate was 1.10%.

## 12. Demand operating loan

Through a mirror banking agreement with its parent Company the Corporation has available to its use a $10,000,000 revolving line of credit. The Corporation provides a guarantee on this facility, as outlined in note 21.

## 13. Accounts payable and accrued liabilities

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Trade | $ 8,275,376 | $ 9,105,552 | $ 7,326,566 |
| Payroll | 98,001 | 247,769 | 279,179 |
| | $ 8,373,377 | $ 9,353,321 | $ 7,605,745 |

## 14. Long-term debt

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Finance lease obligation | $ 289,759 | $ 405,355 | $ 514,727 |
| Demand note (a) | 10,000,000 | --- | --- |
| Shareholder notes (b) | 8,038,524 | 8,038,524 | 8,038,524 |
| Shareholder demand notes (c) | 2,083,391 | 2,083,391 | 2,083,391 |
| Bank loans | --- | --- | 451 |
| | 20,411,674 | 10,527,270 | 10,637,093 |
| Less: current portion | 108,049 | 2,199,211 | 2,192,675 |
| | $ 20,303,625 | $ 8,328,059 | $ 8,444,418 |

(a) Demand note

The Corporation has a demand promissory note payable to ERTH Corporation for $10,000,000 (2014 - nil) which bears interest at 7.25%. This note is unsecured. There are no fixed repayment terms associated with the principal outstanding and no principal amounts are anticipated to be paid over the next thirteen months.

(b) Shareholder notes

The long-term debt represents amounts owing to the municipal shareholders of ERTH Corporation for purchase of the respective Municipality's Hydro Electric Commission's net assets. The rate of interest is currently 7.25% and is set by the Board of Directors, from time to time. There are no fixed repayment terms associated with the principal outstanding and no principal amounts are anticipated to be paid over the next thirteen months. The loan is secured by a second position General Security Agreement covering accounts receivable, inventory and equipment, including motor vehicles.

The amounts owing to the municipalities are as follows:

| | 2015 | 2014 |
|---|---|---|
| Aylmer | $ 1,694,863 | $ 1,694,863 |
| Central Elgin | 806,436 | 806,436 |
| East Zorra Tavistock | 569,073 | 569,073 |
| Ingersoll | 3,402,080 | 3,402,080 |
| Norwich | 763,755 | 763,755 |
| Southwest Oxford | 192,062 | 192,062 |
| Zorra | 610,255 | 610,255 |
| | $ 8,038,524 | $ 8,038,524 |

## 14. Long-term debt (continued)

(c) Shareholder demand notes

The Corporation has a demand promissory note payable to the Municipality of West Perth for $900,000 (2014 - $900,000) which bears interest at 7%. Interest is payable in monthly instalments of $5,250. This note is unsecured. During the year, the terms were renegotiated such that there are no fixed repayment terms associated with the principal outstanding and no principal amounts are anticipated to be paid over the next thirteen months.

The Corporation has a second demand promissory note payable to the Municipality of West Perth for $1,183,391 (2014 - $1,183,391) which bears interest at 7.25%. There are no fixed terms of repayment. This note is unsecured. During the year, the terms were renegotiated such that there are no fixed repayment terms associated with the principal outstanding and no principal amounts are anticipated to be paid over the next thirteen months.

(d) Contractual maturities

| | Less than one year | Between one and five years | More than five years | Total |
|---|---|---|---|---|
| **Future min lease payments** | | | | |
| 2015 | $121,872 | $ 190,628 | - | $312,500 |
| 2014 | 136,241 | 312,500 | - | 448,741 |
| Jan 1, 2014 | 136,241 | 448,741 | - | 584,982 |
| **Interest** | | | | |
| 2015 | $ 13,822 | $ 8,967 | - | $ 22,741 |
| 2014 | 20,421 | 22,965 | - | 43,386 |
| Jan 1, 2014 | 27,408 | 42,847 | - | 70,255 |
| **Present value of min lease Payments** | | | | |
| 2015 | $108,049 | $181,710 | - | $289,759 |
| 2014 | 115,820 | 289,535 | - | 405,355 |
| Jan 1, 2014 | 108,833 | 405,894 | - | 514,727 |

## 15. Post-employment benefits

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2015, the Corporation made employer contributions of $410,667 to OMERS (2014 - $363,220). As at December 31, 2015, OMERS had approximately 461,000 members, of whom 46 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2015, which reported that the plan was 91.5% funded, with an unfunded liability of $7 billion. This unfunded liability is likely to result in future payments by participating employers and members.

**15. Post-employment benefits (continued)**

(b) Post-employment benefits other than pension

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and remeasurements recognized for post-employment benefit plans.

| Reconciliation of the obligation | 2015 | 2014 |
|---|---|---|
| Defined benefit obligation, beginning of year | $ 794,900 | $ 650,200 |
| Included in profit or loss | | |
| Current service cost | 26,100 | 19,800 |
| Interest cost | 31,300 | 32,100 |
| Past service cost | --- | --- |
| | 852,300 | 702,100 |
| Included in OCI | | |
| Actuarial (gains) losses arising from: | | |
| changes in experience | (500) | 1,300 |
| changes in financial assumptions | --- | 112,800 |
| | (500) | 114,100 |
| | 851,800 | 816,200 |
| Benefits paid | 22,700 | 21,300 |
| Defined benefit obligation, end of year | $ 829,100 | $ 794,900 |

| Actuarial assumptions | 2015 | 2014 |
|---|---|---|
| Discount (interest) rate | 4.00% | 4.00% |
| Salary levels | 2.50% | 2.50% |
| Medical Costs | 8.00% | 8.00% |
| Dental Costs | 4.50% | 4.50% |

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $150,900. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $150,900.

## 16. Share capital

| | 2015 | 2014 |
|---|---|---|
| Authorized: | | |
| Unlimited number of common shares | | |
| Issued: | | |
| 10,000 common shares | $10,855,585 | $10,855,585 |

Dividends

The holders of the common shares are entitled to receive dividends as declared from time to time.

The Corporation paid aggregate dividends in the year on common shares of $200 per share (2014 - nil), which amount to total dividends paid of $2,000,000 during 2015 (2014 - nil).

## 17. Other revenue

| | 2015 | 2014 |
|---|---|---|
| Service | $ 454,037 | $ 449,134 |
| Contributions received from customers | 19,080 | 6,758 |
| Dividends | --- | 1,027 |
| | $ 473,117 | $ 456,919 |

## 18. Employee salaries and benefits

| | 2015 | 2014 |
|---|---|---|
| Salaries, wages and benefits | $ 2,629,047 | $ 2,592,483 |
| CPP and EI remittances | 166,033 | 160,883 |
| Contributions to OMERS | 410,667 | 363,220 |
| | $ 3,205,747 | $ 3,116,586 |

## 19. Operating expenses

| | 2015 | 2014 |
|---|---|---|
| Contract/consulting | $ 310,859 | $ 224,898 |
| Materials and supplies | 448,729 | 433,129 |
| Vehicles | 330,341 | 314,802 |
| Billing and collecting | 822,342 | 760,321 |
| Office and administration | 963,384 | 749,749 |
| Losses on disposal of property, plant and equipment | 20,829 | 9,843 |
| Other | 89,683 | 76,660 |
| | $ 2,985,667 | $ 2,569,402 |

## 20. Finance income and costs

| | 2015 | 2014 |
|---|---|---|
| Finance income | | |
| Interest income on bank deposits | $ --- | $ 22,712 |
| Finance costs | | |
| Interest expense on long-term debt | 1,308,681 | 1,308,400 |
| Interest expense on customer deposits | 1,821 | 11,963 |
| Other | 10,226 | 69,438 |
| | 1,320,728 | 1,389,801 |
| Net finance costs recognized in profit or loss | $ 1,320,728 | $ 1,367,089 |

## 21. Commitments and contingencies

Contractual Obligations

As at December 31, 2015 the Corporation has entered into various purchase agreements to acquire a bucket truck in the amount of $335,995 to be paid in 2016.

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation’s financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2015, no assessments have been made.

## 22. Guarantees

The Corporation has guaranteed the operating and term loans of its parent Company ERTH Corporation up to 25% of the Corporations equity or $3,386,272. The loans are secured by a General Security Agreement covering all assets of the Corporation and a pledge of the shares of the Corporation. As the Corporation does not expect to be in a position where it would need to honour this guarantee in the foreseeable future, no liability has been recorded in these financial statements.

## 23. Operating leases

The Corporation is committed to lease agreements for various vehicles and equipment.

The future minimum non-cancellable annual lease payments are as follows:

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Less than one year | $ 43,629 | $ 59,833 | $ 64,674 |
| Between one and five years | 25,480 | 69,109 | 128,942 |
| More than five years | --- | --- | --- |
| | $ 69,109 | $ 128,942 | $ 193,616 |

During the year ended December 31, 2015 an expense of $59,833 (2014 - $64,674) was recognized in operating expenses in the statement of comprehensive income in respect of operating leases.

## 24. Related party transactions

(a) Parent and ultimate controlling party

The sole shareholder of the Corporation is ERTH Corporation, which in turn is wholly-owned by eight municipalities Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford, Zorra and West Perth.

(b) Companies under common control

ERTH Corporation owns 100% of the issued and outstanding shares ERTH Limited.

ERTH Business Technologies Inc., ERTH (Holdings) Inc. and J-Mar Line Maintenance Inc. are wholly-owned subsidiaries of ERTH Limited.

(c) Outstanding balances with related parties

The following represents due to/from in the normal course of operations:

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Due from: | | | |
| ERTH Corporation | $ 25,484 | $ 15,242 | $ 16,372 |
| ERTH (Holdings) Inc. | 71,544 | 32,891 | 29,811 |
| ERTH Business Technologies Inc. | 129 | 131 | 1,204 |
| J-Mar Line Maintenance Inc. | --- | 107 | --- |
| | $ 97,157 | $ 48,371 | $ 47,387 |

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Due to: | | | |
| ERTH Corporation | $ 588,753 | $ 412,109 | $ 109,205 |
| ERTH (Holdings) Inc. | 96,105 | 326,019 | 142,404 |
| Municipality of West Perth | --- | --- | 204,019 |
| Town of Aylmer | 218,263 | 199,159 | 187,182 |
| | $ 903,121 | $ 937,287 | $ 642,810 |

**24. Related party transactions (continued)**

(c) Outstanding balances with related parties (continued)

The transactions between the Corporation and its related parties are measured at the exchange amount, which is the amount of consideration paid or received as established and agreed to by the related parties, unless otherwise noted.

The Corporation has contracted ERTH (Holdings) Inc. and ERTH Business Technologies Inc., to provide maintenance and upgrades to the existing capital infrastructure of the Corporation and administrative services.

(d) Transactions with parent

The Corporation has a contract with ERTH Corporation, the parent company, for management services and rental of facilities used by the Corporation.

During the year, the Corporation paid management services, consulting services and rent fees to its parent in the amount of $1,032,069, $222,281 and $212,820 respectively (2014 - $1,645,262, $527,727 and $205,000). The Corporation also charged its parent company $108,721 (2014 - $134,947) for operations and administrative services.

(e) Transactions with companies under common control

During the year, the Corporation had the following transactions with related parties as follows:

- sold operations and administration services of nil (2014 - $1,508) to ERTH Business Technologies Inc.
- purchased capitalized items of $12,465 (2014 - $17,248) and sold operations, administration services of nil (2014 - $108) and sold capital equipment of $12,000 (2014 – nil) to J-Mar Line Maintenance Inc.
- purchased capitalized items of $65,733 (2014 - $142,613), operations, maintenance and administration services of $524,710 (2014 - $418,015), sold operations, maintenance and admission services of $327,766 (2014 - $220,531) and sold capital assets of $5,000 (2014 - nil) to ERTH (Holdings) Inc.

In the ordinary course of business, the Corporation delivers electricity to ERTH (Holdings) Inc. Electricity is billed to ERTH (Holdings) Inc. at prices and under terms approved by the OEB, if applicable.

(f) Transactions with ultimate parents

The Corporation delivers electricity to the eight municipalities throughout the year for the electricity needs of the municipalities and their related organizations. Electricity delivery charges are at prices and under terms approved by the OEB. The Corporation also provides additional services to the Municipality of Norwich, the Town of Aylmer and the Town of Ingersoll for water and waste water billing and customer care services.

The Municipality of West Perth charges the Corporation for tree trimming and annual rent.

## 25. Financial instruments and risk management

### Fair value disclosure

The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, due from/to related parties and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the long-term debt at December 31, 2015 is $19,248,053 (2014 - $9,661,081). The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rate used to calculate fair value at December 31, 2015 was 4.54% (2014 – 4.77%).

The fair value of available for sale financial assets is based on the closing value of the equity in the publically traded markets.

### Financial risks

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the municipalities of Aylmer, Central Elgin, East-Zorra Tavistock, Ingersoll, Norwich, South-West Oxford, Zorra and West Perth. As a result, the Corporation did not earn a significant amount of revenue from any one individual customer.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the allowance for impairment at December 31, 2015 is $804,806 (2014 - $684,944). An impairment loss of $87,793 (2014 - $22,618) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2015, approximately $174,806 (2014 - $79,217) is considered 60 days past due. The Corporation has over 18,000 customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2015, the Corporation holds security deposits in the amount of $760,379 (2014 - $ 752,557).

**25. Financial instruments and risk management (continued)**

(b) Market risk

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

The Corporation minimizes interest rate risk by issuing long-term fixed rate debt.

(c) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation, through its parent company has access to a $38 million credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2015, $30 million has been drawn under the parent company's credit facility.

The Corporation also has a bilateral facility for $2.3 million (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $2,246,667 has been drawn and posted with the IESO (2014 - $2,246,667).

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days.

(d) Capital disclosures

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2015, shareholder's equity amounts to $13,545,089 (2014 - $14,590,175) and long-term debt amounts to $10,411,674 (2014 - $10,527,270).

## 26. Explanation of transition to IFRS

As stated in note 2(b), these are the Corporation’s first financial statements prepared in accordance with IFRS.

The accounting policies set out in note 3 have been applied in preparing the financial statements for the year ended December 31, 2015, the comparative information presented in these financial statements for the year ended December 31, 2014, and in the preparation of the opening IFRS Statement of Financial Position as at January 1, 2014 (the Corporation’s date of transition).

In preparing its opening IFRS Statement of Financial Position, the Corporation has adjusted the amounts reported previously in the financial statements prepared in accordance with Canadian general accepted accounting principles (CGAAP). An explanation of how the transition from CGAAP to IFRS has affected the Corporation’s financial position, financial performance and cash flows is set out in the following tables and the notes accompanying the tables.

Regulatory accounts

IFRS14: *Regulatory Deferral Accounts*, permits an entity to continue to account for regulatory deferral account balances in its financial statements in accordance with its previous GAAP when it adopts IFRS. An entity is permitted to apply the requirements of this standard in its first IFRS financial statements if and only if it conducts rate-regulated activities and recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP. This standard exempts an entity from applying paragraph 11 of IAS8: *Accounting policies, changes in accounting estimates and errors*, to its accounting policies for the recognition, measurement, impairment and derecognition of regulatory deferral account balances.

IFRS 14 is effective from periods beginning on or after January 1, 2016, however, early application is permitted. The Corporation has elected to apply this Standard in its first IFRS financial statements.

IFRS 1 Exemptions

IFRS 1 *First-time adoption of International Financial Reporting Standards* sets out the procedures that the Corporation must follow when it adopts IFRS for the first time as the basis for preparing its financial statements. The Corporation is required to establish its IFRS accounting policies as at December 31, 2015 and, in general, apply these retrospectively to determine the IFRS opening statement of financial position as its date of transition, January 1, 2014. This standard provides a number of mandatory and optional exemptions to this general principle. These are set out below, together with a description in each case of the exemption adopted by the Corporation.

**26. Explanation of transition to IFRS (continued)**

(a) Business combinations

IFRS 1 provides an optional exemption whereby a first-time adopter may elect not to apply IFRS 3 Business Combinations retrospectively to business combinations that occurred prior to the date of transition. The Corporation has elected this exemption and did not restate business combinations that occurred prior to the date of transition.

(b) Deemed cost

IFRS 1 provides an optional exemption for a first-time adopter with rate-regulated activities to use the carrying amount of PP&E and intangible assets as deemed cost on transition date when the carrying amount includes costs that do not qualify for capitalization in accordance with IFRS. The Corporation elected this exemption and used the carrying amount of the PP&E and intangible assets under CGAPP as deemed cost on transition date. The carrying amount used as deemed cost is $28,066,972 for PP&E and $523,138 for intangible assets.

If an entity applies this exemption, at the date of transition to IFRS, it shall test for impairment each item for which this exemption is used. The assets were tested for impairment at the date of transition and it was determined that the assets were not impaired.

(c) Transfer of assets from customers

The corporation has elected to apply the transitional provisions in IFRIC 18 *Transfers of Assets from Customers.* This provision states that the effective date of this standard should be July 1, 2009 or the date of transition to IFRS whichever is the later.

## 26. Explanation of transition to IFRS (continued)

### Reconciliation of statement of financial position and statement of changes in equity

| January 1, 2014 | Note | CGAAP | Presentation differences | Measurement & recognition differences | IFRS |
|---|---|---|---|---|---|
| Accounts receivable | - | $12,304,748 | $(4,376,148) | $ --- | $ 7,928,600 |
| Due from related parties | - | 1,204 | 46,183 | --- | 47,387 |
| Unbilled revenue | - | --- | 4,376,148 | --- | 4,376,148 |
| Materials and supplies | - | 96,769 | --- | --- | 96,769 |
| Prepaid expenses | - | 122,226 | --- | --- | 122,226 |
| Current regulatory balances | - | 1,766,074 | (1,766,074) | --- | --- |
| Property, plant and equipment | (a),(c),(d) | 28,513,443 | (446,471) | --- | 28,066,972 |
| Intangible assets | (a) | 76,667 | 446,471 | --- | 523,138 |
| Investments | - | 18,621 | --- | --- | 18,621 |
| Long-term regulatory balances | - | 1,872,377 | (1,872,377) | --- | --- |
| Deferred tax assets | (e) | 566,000 | (150,000) | 7,000 | 423,000 |
| Payment in lieu of taxes receivable | | --- | 190 | --- | 190 |
| Total assets | - | 45,338,129 | (3,735,078) | 7,000 | 41,603,051 |
| Regulatory balances | - | --- | 3,638,451 | --- | 3,638,451 |
| Total assets and regulatory balances | - | $45,338,129 | $ (96,627) | $ 7,000 | $45,241,502 |
| Bank overdraft | - | $ 6,033,352 | $ --- | $ --- | $ 6,033,352 |
| Accounts payable and accrued liabilities | - | 7,605,555 | 190 | --- | 7,605,745 |
| Due to related parties | - | 596,627 | 46,183 | --- | 642,810 |
| Related party notes payable | - | 2,083,391 | (2,083,391) | --- | --- |
| Current portion of long-term debt | - | 109,284 | (109,284) | --- | --- |
| Long-term debt due within a year | - | --- | 2,192,675 | --- | 2,192,675 |
| Customer deposits | (c) | 905,292 | (246,707) | --- | 658,585 |
| Deferred revenue | (c) | --- | 246,707 | --- | 246,707 |
| Current regulatory balances | - | 1,084,879 | (1,084,879) | --- | --- |
| Long-term debt | - | 405,894 | 8,038,524 | --- | 8,444,418 |
| Long-term related party | - | 8,038,524 | (8,038,524) | --- | --- |
| Post-employment benefits | (f) | 622,500 | --- | 27,700 | 650,200 |
| Deferred tax liabilities | - | 566,000 | (566,000) | --- | --- |
| Long-term regulatory balances | - | 3,755,560 | (3,755,560) | --- | --- |
| Total liabilities | - | 31,806,858 | (5,360,066) | 27,700 | 26,474,492 |
| Share capital | - | 10,855,585 | --- | --- | 10,855,585 |
| Retained earnings | (f) | 2,675,686 | --- | (27,700) | 2,647,986 |
| Total liabilities and equity | - | 13,531,271 | --- | (27,700) | 13,503,571 |
| Regulatory balances | - | --- | 5,256,439 | 7,000 | 5,263,439 |
| Total liabilities, equity and regulatory balances | - | $45,338,129 | $ (96,627) | $ 7,000 | $45,241,502 |

## 26. Explanation of transition to IFRS (continued):

**Reconciliation of statement of financial position and statement of changes in equity**

| December 31, 2014 | Note | CGAAP | Presentation differences | Measurement & recognition differences | IFRS |
|---|---|---|---|---|---|
| Accounts receivable | - | $10,015,767 | $(4,959,235) | $ --- | $ 5,056,532 |
| Due from related parties | - | 238 | 48,133 | --- | 48,371 |
| Unbilled revenue | - | --- | 4,959,235 | --- | 4,959,235 |
| Material and supplies | - | 169,979 | --- | --- | 169,979 |
| Prepaid expenses | - | 112,967 | --- | --- | 112,967 |
| Current regulatory | - | 1,617,398 | (1,617,398) | --- | --- |
| Property, plant and equipment | (c),(d) | 30,169,411 | 327,778 | --- | 30,497,189 |
| Intangible assets | - | 76,667 | 476,410 | --- | 553,077 |
| Investment | - | 20,805 | --- | --- | 20,805 |
| Long-term regulatory balances | - | 3,369,019 | (3,369,019) | --- | --- |
| Deferred tax assets | (e) | 339,000 | (104,000) | 38,000 | 273,000 |
| Total assets | - | 45,891,251 | (4,200,096) | 38,000 | 41,660,155 |
| Regulatory balances | - | --- | 4,986,417 | --- | 4,986,417 |
| Total assets and regulatory balances | - | $45,891,251 | $ 786,321 | $ 38,000 | $46,677,572 |
| Bank overdraft | - | $5,411,329 | $ --- | $ --- | $5,411,329 |
| Accounts payable and accrued liabilities | - | 9,353,321 | --- | --- | 9,353,321 |
| Due to related parties | - | 889,154 | 48,133 | --- | 937,287 |
| Related parties notes payable | - | 2,083,391 | (2,083,391) | --- | --- |
| Current portion of long-term debt | - | 115,820 | (115,820) | --- | --- |
| Long-term debt due within one year | - | --- | 2,199,211 | --- | 2,199,211 |
| Customer deposits | (c) | 973,282 | (220,725) | --- | 752,557 |
| Deferred revenue | (c) | --- | 347,415 | --- | 347,415 |
| Current regulatory balances | - | 2,312,479 | (2,312,479) | --- | --- |
| Payment in lieu of income taxes | - | 165,694 | --- | --- | 165,694 |
| Long-term debt | - | 289,535 | 8,038,524 | --- | 8,328,059 |
| Long-term related party | - | 8,038,524 | (8,038,524) | --- | --- |
| Post-employment benefits | (f) | 653,100 | --- | 141,800 | 794,900 |
| Deferred revenue | - | --- | 677,498 | --- | 677,498 |
| Deferred tax liabilities | - | 339,000 | (339,000) | --- | ---- |
| Lont-term regulatory balances | - | 534,646 | (534,646) | --- | --- |
| Total liabilities | - | 31,159,276 | (2,333,804) | 141,800 | 28,967,272 |
| Share capital | - | 10,855,585 | --- | --- | 10,855,585 |
| Retained earnings | (f) | 3,876,390 | --- | (29,884) | 3,846,506 |
| Accumulated OCI | (f) | --- | --- | (111,916) | (111,916) |
| Total liabilities and equity | - | 45,891,251 | (2,333,804) | --- | 43,557,447 |
| Regulatory balances | - | --- | 3,082,125 | 38,000 | 3,120,125 |
| Total liabilities, equity and regulatory balances | - | $45,891,251 | $ 786,321 | $ 38,000 | $46,677,572 |

## 26. Explanation of transition to IFRS (continued)

### Reconciliation of net income for 2014

| | Note | CGAAP | Presentation differences | Measurement & recognition differences | IFRS |
|---|---|---|---|---|---|
| Revenue | | | | | |
| Sale of energy | - | $49,839,585 | $(2,407,556) | $ --- | $47,432,029 |
| Distribution revenue | - | 9,620,820 | --- | --- | 9,620,820 |
| Service income | - | 449,135 | (449,135) | --- | --- |
| Interest income | - | 3,210 | (3,210) | --- | --- |
| Other | (c) | --- | 456,919 | --- | 456,919 |
| Operating expenses | | | | | |
| Cost of power purchased | - | 49,839,585 | 1,069,630 | --- | 50,909,215 |
| Billing and collecting | - | 1,095,410 | (1,095,410) | --- | --- |
| Community relations | - | 34,599 | (34,599) | --- | --- |
| Direct operations | - | 3,605,188 | (3,605,188) | --- | --- |
| Office and administration | - | 715,150 | (715,150) | --- | --- |
| Regulatory and professional | - | 225,798 | (225,798) | --- | --- |
| Employee salaries and benefits | - | --- | 3,116,586 | --- | 3,116,586 |
| Operating expenses | - | --- | 2,569,402 | --- | 2,569,402 |
| Depreciation and amortization | (c) | 1,467,478 | 6,758 | --- | 1,474,236 |
| MIFRS regulatory adjustment | - | 147,212 | (147,212) | --- | --- |
| Finance income | - | 69,802 | (47,090) | --- | 22,712 |
| Finance costs | - | 1,425,585 | (35,784) | --- | 1,389,801 |
| Income tax expense | - | 216,000 | 181,000 | --- | 397,000 |
| Loss on sale of equipment | (d) | 9,843 | (9,843) | --- | --- |
| Net income for the year | - | 1,200,704 | (3,524,464) | --- | (2,323,760) |
| Net movement in regulatory balances, net of tax | - | --- | 3,522,280 | --- | 3,522,280 |
| Net income and net movement in regulatory balances | - | 1,200,704 | (2,184) | --- | 1,198,520 |
| Other comprehensive income | | | | | |
| Fair value instruments | - | --- | 2,184 | --- | 2,184 |
| Remeasurement of post-employment benefits | (f) | --- | --- | (114,100) | (114,100) |
| Tax on remeasurements | (e) | --- | --- | 31,000 | 31,000 |
| Net movement in regulatory balances, net of tax | (e) | --- | --- | (31,000) | (31,000) |
| Total comprehensive income for the year | - | $ 1,200,704 | $ --- | $ (114,100) | $ 1,086,604 |

**26. Explanation of transition to IFRS (continued)**

**Notes to the reconciliations**

The impact on deferred tax of the adjustments described below is set out in note (e).

(a) The Corporation has elected under IFRS 1 to use the carrying value of items of PP&E and intangible assets as the deemed cost at the date of transition. Therefore, there has been no change to the net PP&E and intangible assets at January 1, 2014. The effect of this transitional adjustment is a decrease to the original cost and accumulated depreciation of the affected PP&E and intangible assets by $17,365,438 and $760,874 respectively, the CGAAP accumulated depreciation amount, on January 1, 2014.

(b) IFRS requires that borrowing costs related to the construction of the qualifying assets be capitalized. The Corporation has applied IAS 23 to all qualifying assets that were in progress or commenced since January 1, 2014. No qualifying assets were identified and therefore no borrowing costs were capitalized for the year ended December 31, 2014.

(c) Under CGAAP, customer contributions were netted against the cost of PP&E and amortized to profit or loss as an offset to depreciation expense, on the same basis as the related assets. Under IFRS, customer contributions are recognized as deferred revenue, not netted against PP&E, and amortized into profit or loss over the life of the related asset.

The effect of the above is to increase deferred revenue by $246,707 at January 1, 2014 and by $911,739 at December 31, 2014; to decrease construction deposits by $246,707 at January 1, 2014 and by $220,725 at December 31, 2014; to increase PP&E by $810,946 at December 31, 2014 and to increase other revenue and decrease depreciation expense by $119,932 for the year ended December 31, 2014.

(d) Under CGAAP for rate regulated entities, the Corporation removed assets from the accounts at the end of their estimated useful lives. IFRS requires assets to be removed from the accounts when they have been removed from service.

The effect is to decrease PP&E by $31,785 at December 31, 2014 and to increase loss on retirement of PP&E by $9,843 for the year ended December 31, 2014.

(e) The Corporation adopted the revised Employee Benefits standard effective January 1, 2014. This revised standard requires recognition of actuarial gains and losses through other comprehensive income. This increased post-employment benefits and decreased retained earnings by $27,700 respectively at January 1, 2014 and increased post-employment benefits by $141,800 at December 31, 2014 with a corresponding decrease to retained earnings of $27,700 and an increase to OCI of $144,100.

**26. Explanation of transition to IFRS (continued)**

(f) The above changes increased the deferred tax asset as follows based on a tax rate of 26.5%:

| | Note | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Post-employment benefits | (e) | $ 31,000 | $ 7,000 |

The effect on the statement of comprehensive income for the year ended December 31, 2014 was to decrease the previously reported income taxes by nil.

Explanation of material adjustments to the statement of cash flows for 2014

There are no material differences between the statement of cash flows presented under IRFS and the statement of cash flows presented under CGAAP.

# ATTACHMENT 9

## FINANCIAL STATEMENTS – WEST COAST HURON ENERGY - 2016

# West Coast Huron Energy Inc.
# Financial Statements
# December 31, 2016

CHARTERED PROFESSIONAL ACCOUNTANTS
Takalo & Burt

Ronald E. Takalo, B.Math., CPA, CA
Ronald F. Burt, B. Comm., CPA, CA

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N7A 1M4
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## INDEPENDENT AUDITORS' REPORT

To the Shareholder of
West Coast Huron Energy Inc.

We have audited the accompanying financial statements of West Coast Huron Energy Inc., which comprise the balance sheet as at December 31, 2016, and the statements of earnings and other comprehensive income, changes in equity and cash flows for the year then ended and a summary of significant accounting policies and other explanatory information.

**Management's Responsibility for the Financial Statements**
Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

**Auditors' Responsibility**
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, these financial statements present fairly, in all material respects, the financial position of West Coast Huron Energy Inc. as at December 31, 2016 and the results of its operations and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

TAKALO & BURT

LICENSED PUBLIC ACCOUNTANTS
CHARTERED PROFESSIONAL ACCOUNTANTS
CHARTERED ACCOUNTANTS

Goderich, Ontario
July 20, 2017

## West Coast Huron Energy Inc.
## Statement of Earnings and Other Comprehensive Income

| For the year ended December 31 | 2016 | 2015 (expressed in CDN$) |
|---|---|---|
| **Revenue** | | |
| Sale of energy | **$ 11,271,592** | $ 10,081,745 |
| Distribution revenue | **2,332,148** | 2,348,941 |
| Regulatory adjustment to sale of energy | **294,557** | 415,305 |
| Other revenue (Note 17) | **182,758** | 148,863 |
| Contributions in aid of construction | **8,899** | 6,840 |
| | **14,089,954** | 13,001,694 |
| **Cost of power** | | |
| Power purchased | **11,271,592** | 10,081,745 |
| **Net distribution revenue** | **2,818,362** | 2,919,949 |
| **Expenditures** | | |
| Administration and general | **908,418** | 794,774 |
| Billing and collecting (Note 19) | **477,549** | 428,709 |
| Maintenance | **297,310** | 390,269 |
| Amortization (Note 18) | **279,897** | 257,196 |
| Operations | **136,321** | 140,160 |
| Community relations | **14,341** | 8,460 |
| | **2,113,836** | 2,019,568 |
| **Earnings from operations** | **704,526** | 900,381 |
| Finance income (Note 21) | **3,596** | 6,803 |
| Finance charge (Note 21) | **(222,487)** | (218,542) |
| **Net earnings before taxes and net regulatory movements** | **485,635** | 688,642 |
| Payments-in-lieu of taxes (Note 22) | **23,526** | 25,500 |
| Future taxes (Note 22) | **22,970** | 22,060 |
| **Net earnings before net regulatory movements** | **439,139** | 641,082 |
| Net movements in regulatory balances | **(294,557)** | (415,305) |
| **Net income and regulatory movements** | **144,582** | 225,777 |
| Other comprehensive income | - | - |
| **Total earnings and other comprehensive income for the year** | **$ 144,582** | $ 225,777 |

See accompanying notes to the financial statements

# West Coast Huron Energy Inc.
## Statement of Changes in Shareholder's Equity
**For the year ended December 31**

| | Stock | Other Income | Retained Earnings |
|---|---|---|---|
| Balance, January 1, 2015 | $ 3,410,092 | $ (89,250) | $ 2,236,883 |
| Total income and other comprehensive income for the year | - | - | 225,777 |
| Dividend | - | - | (100,000) |
| Balance, December 31, 2015 | 3,410,092 | (89,250) | 2,362,660 |
| Total income and other comprehensive income for the year | - | - | 144,582 |
| Dividend | - | - | (175,000) |
| Balance, December 31, 2016 | $ 3,410,092 | $ (89,250) | $ 2,332,242 |

See accompanying notes to the financial statements

## West Coast Huron Energy Inc.
## Balance Sheet
**As at December 31**

| | 2016 | 2015 |
|---|---|---|
| **ASSETS** | | |
| **Current** | | |
| Cash | $ 1,536,278 | $ 1,611,038 |
| Receivables (Note 6) | 1,331,292 | 811,886 |
| Unbilled revenue | 1,248,924 | 1,161,982 |
| Payments-in-lieu of corporate taxes receivable | 13,556 | 8,739 |
| Prepaids | 10,510 | 10,510 |
| Total current assets | 4,140,560 | 3,604,155 |
| Property, plant and equipment - net (Note 8) | 9,618,422 | 9,236,214 |
| Intangibles (Note 9) | 124,462 | 138,153 |
| **Total assets** | 13,883,444 | 12,978,522 |
| Regulatory balances (Note 7) | 65,671 | 373,789 |
| **Total assets and regulatory balances** | $ 13,949,115 | $ 13,352,311 |
| **LIABILITIES** | | |
| **Current** | | |
| Payables and accruals (Note 10) | $ 1,968,600 | $ 1,588,809 |
| Town of Goderich demand loan (Note 12) | 2,000,000 | 2,000,000 |
| Dividends payable | 175,000 | 100,000 |
| Current portion of bank loans | 705,286 | 152,322 |
| Current portion of customer deposits | 50,000 | 50,000 |
| **Total current liabilities** | 4,898,886 | 3,891,131 |
| **Long-term** | | |
| Note payable (Note 14) | 974,454 | 974,454 |
| Bank loans (Note 13) | 1,546,204 | 2,037,628 |
| Contributions in aid of construction (Note 11) | 425,046 | 311,168 |
| Post-employment benefits obligation (Note 15) | 291,961 | 303,457 |
| Customer deposits | 93,193 | 94,093 |
| | 3,330,858 | 3,720,800 |
| Future income taxes (Note 22) | 43,409 | 20,439 |
| **Total liabilities** | 8,273,153 | 7,632,370 |
| **SHAREHOLDER'S EQUITY** | | |
| Share capital (Note 23) | 3,410,092 | 3,410,092 |
| Retained earnings | 2,332,242 | 2,362,660 |
| Other comprehensive income | (89,250) | (89,250) |
| **Total shareholder's equity** | 5,653,084 | 5,683,502 |
| **Total liabilities and shareholder's equity** | 13,926,237 | 13,315,872 |
| Regulatory balances (Note 7) | 22,878 | 36,439 |
| **Total liabilities, shareholder's equity and regulatory balances** | $ 13,949,115 | $ 13,352,311 |

**APPROVED ON BEHALF OF THE BOARD:**

[redacted] Director

Director

## West Coast Huron Energy Inc.
## Statement of Cash Flows
**For the year ended December 31**

| | 2016 | 2015 |
|---|---|---|
| **Operating activities** | | |
| Net earnings | $ 144,582 | $ 225,777 |
| Adjustments for non-cash items | | |
| Amortization of property, plant and equipment and intangibles | 279,899 | 257,196 |
| Amortization of contributions in aid of construction | (8,899) | (6,840) |
| Loss (gain) on disposal of property, plant and equipment | 42,510 | 16,046 |
| Increase in post-employment benefits obligation | (11,496) | (10,816) |
| Non-cash adjustments to regulatory asset/liabilities | 36,253 | 36,254 |
| Change in non-cash working capital balances (Note 25) | (208,404) | (416,332) |
| Net cash provided by operating activities | 274,445 | 101,285 |
| **Financing activities** | | |
| Increase in bank loan | 61,540 | 244,800 |
| Dividends paid | (100,000) | (125,000) |
| Increase (decrease) in customer deposits | (900) | (4,513) |
| Net cash provided by financing activities | (39,360) | 115,287 |
| **Investing activities** | | |
| Purchase of property, plant and equipment | (727,179) | (506,021) |
| Purchase of intangibles | - | (36,555) |
| Decrease (increase) in regulatory assets/liabilities | 294,557 | 415,305 |
| Proceeds of contributions in aid of construction | 122,777 | 46,777 |
| Net cash provided by investing activities | (309,845) | (80,494) |
| **Net increase (decrease) in cash** | (74,760) | 136,078 |
| **Cash**, beginning of year | 1,611,038 | 1,474,960 |
| **Cash**, end of year | $ 1,536,278 | $ 1,611,038 |

| | | |
|---|---|---|
| **Cash consists of:** | | |
| Cash | $ 1,536,278 | $ 1,611,038 |

## 1. NATURE OF BUSINESS

West Coast Huron Energy Inc. was incorporated on October 19, 1999 under the Business Corporations Act(Ontario) in accordance with the Electricity Act. The Corporation is a wholly owned subsidiary of the Corporation of the Town of Goderich and is domiciled in Canada. The address of the Corporation's registered office is 57 West Street, Goderich, Ontario.

The Town of Goderich passed a Bylaw transferring certain assets and liabilities of the Public Utilities Commission of the Town of Goderich Municipal Electrical Utility to this corporation. In exchange for these assets, the Town of Goderich received a promissory note and common shares.

The principal activity of the corporation is to distribute electricity to residents and businesses in the Town of Goderich under license issued by the Ontario Energy Board ("OEB"). The Company is regulated by the Ontario Energy Board ("OEB") and adjustments to the distribution and power rates require OEB approval.

## 2. BASIS OF PRESENTATION

### Statement of compliance

The financial statement of the corporation have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Standards Board ("IASB") and interpretations as issued by the International Financial Reporting Interpretations Committee 9"IFRIC") of the IASB.

**The financial statements were authorized by the Board of Directors on July 20, 2017.**

### Basis of measurement

The financial statements have been prepared on a historical cost basis.

### Presentation currency

The financial statements are presented in Canadian dollars, which is also the functional currency of the Corporation. All financial information has been rounded to the nearest dollar except when otherwise noted.

### Use of estimates and judgements

The preparation of financial statements in accordance with IFRS requires management to make estimates, assumptions and judgements that affect the application of accounting policies and the reported amounts and disclosures made in the financial statements. Actual results could differ from the current estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected.

Significant sources of estimation uncertainty include the following:

i) **Useful lives of depreciable assets**
Depreciation and amortization expense is based on estimates of the useful lives of property, plant and equipment and intangible assets. Management estimates the useful lives of its property, plant and equipment and intangible assets based on judgement, historical experience and an assets study conducted by an independent consulting firm on assets most commonly used in the distributors of electricity in Ontario at the request of the Ontario Energy Board.

ii) **Employee future benefits**
The cost of post employment medical and insurance benefits are determined using actuarial valuation. This valuation is complex and involves making numerous assumptions . The long-term nature, complexity and sensitivity of the valuation to changes in interest rates, post employment medical and insurance benefits assumptions makes the reported liability subject to uncertainty. Assumptions are reviewed annually and valuations are recalculated when any significant changes occur.

iii) **Other areas**
There are a number of other areas that require management to make estimates; these include accounts receivable, and income taxes. These amounts are reported based on amounts expected to be recovered/refunded and an appropriate allowance has been provided for estimated unrecoverable amounts based on management's best estimate.

## 3. REGULATION

The Ontario Energy Board has regulatory oversight powers over electricity matters in Ontario. The OEB issues distribution licences to all owners or operators of a distribution system in Ontario. This licence sets out requirements for regulatory accounting principles, the filing process for rate setting purposes as well as many other conditions for operation. The OEB has the authority to approve and fix rates charged for the transmission and distribution of electricity and thereby also to provide rate protection to electricity customers. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from IFRS for enterprises operating in a non-rate regulated environment.

The utility purchases electricity from the wholesale market administered by the Independent Electricity System Operator ("IESO") and recovers the costs of electricity and certain other costs in accordance with procedures mandated by the OEB.

The OEB's regulatory framework for electricity distributors typically regulates the electricity rates using a combination of detailed cost of service reviews and formulatic adjustments based on inflationary factors net of a productivity factor and efficiency factor as determined relative to other electricity distributors.

Operation of the utility in this regulated environment expose it to the following risks:

**Regulatory risk**
Regulatory risk is the risk that the Province and its regulatory, the OEB, could establish a regulatory regime that imposes conditions that restrict the utility from achieving an acceptable rate of return that supports the financial sustainability of its operations. All requests for changes in electricity distribution charges required the approval of the OEB.

**Recovery risk**
Regulatory developments in Ontario's electricity industry including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other allowable recoveries in the future. The corporation is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (a) to recover the forecasted operating costs including depreciation, income taxes and (b) to provide a fair and reasonable return on utility investment. Actual operating conditions may vary from the forecast and actual returns can differ from the approved returns.

## 4. SIGNIFICANT ACCOUNTING POLICIES

The preparation and presentation of financial statements can be significantly affected by the accounting policies selected by the corporation. The financial statements reflect the following significant accounting policies.

**Revenue Recognition**

**Electricity distribution and sale**
Revenue from the sale of energy and distribution of electricity are recorded on the basis of cyclical billings based on electricity usage and includes unbilled revenue accrued in respect of electricity delivered but not yet billed.
The utility is required to charge its customers for the following amounts ( all of which, other than distribution rates, represent a pass through to customers of amounts payable to third parties):

**Commodity charge**
The commodity charge represents the price of electricity consumed by customers and is passed through the IESO to operators of generating stations.

**Retail transmission rate**
The retail transmission rate represents the pass through of costs charged to the utility for the transmission of electricity from generating stations to local distribution networks.

**Wholesale market service charge**
The wholesale market service charge represents a pass through of various wholesale market support costs charged by the IESO.

**Distribution charge**
The distribution charge is designed to recover the costs incurred by the utility in delivering electricity to its customers, as well as the ability to earn the OEB allowed rate of return. The distribution charge is regulated by the OEB and generally consists of a fixed monthly charge and a usage-based (consumption) charge.

The difference between the amounts charged by the utility to its customers, based on regulated rates, and the corresponding commodity, retail transmission and wholesale market service costs billed by the IESO to the utility is recorded as a settlement variance. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the utility's balance sheet and within net movements in regulatory balances, on the utility's statement of earnings and comprehensive income.

**Other revenue**
Other revenue, which includes revenue from services ancillary to the distribution of electricity is recognized as the services are rendered.

Capital contributions received from electricity customers to construct or acquire property, plant and equipment for the purpose of connecting a customer to a network are recorded as contributions in aid of construction and amortized into revenue at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

**Financial assets - classified as loans and receivables**
These financial assets include cash and bank, accounts receivable and unbilled revenue. Collectibility of accounts receivable is reviewed by management on an ongoing basis. Amounts that are known to be uncollectible are written off. A provision for doubtful receivables is recorded when there is evidence that the utility will not be able to collect the amount due. The amount of the provision is recognized in the statement of earnings.

**Financial liabilities**
Accounts payable and accruals, customer deposits and long-term debt are classified as financial liabilities. These liabilities are measured at amortized cost.

**Cash and cash equivalents**
Cash equivalents include cash in bank accounts and short-term investments with maturities of three months or less when purchased.

**Regulatory balances**
The following regulatory treatment has resulted in accounting treatments which differ from IFRS for enterprises operating in an unregulated environment and regulated entities that did not adopt IFRS 14 Regulatory Deferral Accounts:

The corporation has early adopted IFRS 14 Regulatory Deferral Accounts. In accordance with IFRS 14, the corporation has continued to apply the accounting policies it applied in accordance with pre-changeover Canadian GAAP for the recognition, measurement and impairment of assets and liabilities arising from rate regulation.

Regulatory balances provide useful information about the utility's financial position, financial performance and cash flows. Under rate regulated accounting the timing and recognition of certain revenues and expenses may differ from those otherwise expected under other IFRS's in order to reflect the impact of regulatory decisions. The regulatory balances that arise from the timing differences and qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and OEB prescribed accounting principles are segregated on the utility's balance sheet. The netting of regulatory debit and credit balances is not permitted. These regulatory balances represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers based on approvals by the OEB. The change in regulatory balances during the fiscal period is reflected on the statement of earnings and comprehensive income as net movements in regulated balances.

Regulatory deferral balances are recognized and measured initially and subsequently at cost. They are assessed for impairment on the same basis as other non-financial assets as follows:

The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgements, the balances will be recorded in the utility's statement of earning and other comprehensive income in the period the assessment is made.

**Accounts receivable and unbilled revenue**
Accounts receivable are recorded at the invoiced amount and overdue amounts bear interest at the OEB prescribed rate. Unbilled revenue is recorded based on an estimated amount of electricity delivered but not billed. The carrying amount of accounts receivable and unbilled revenue is reduced through an allowance for doubtful accounts, if applicable, and the amount of the related impairment loss is recognized in the statement of earnings and comprehensive income.

Accounts receivable and unbilled revenue are assessed at year end to determine whether there is evidence of impairment. The utility considers historical trends on the timing of recoveries and the amount of loss incurred as well as current economic and credit conditions.

**Inventory**
Inventories consist primarily of small consumable materials mainly related to the maintenance of the electricity infrastructure. The utility classifies all major construction related spare components of its electricity distribution infrastructure as property, plant and equipment. Inventories are measured at the lower of cost and net realizable value, with cost being determined on an average cost basis net of any provision for obsolescence.

**Property, plant and equipment**
Property, plant and equipment are measured at cost less accumulated depreciation and any accumulated impairment losses, if applicable. For property, plant and equipment used in rate-regulated activities, the utility elected to use the exemption available for assets subject to rate regulation such that the previous Canadian GAAP carrying amount became deemed cost under IFRS at the date of transition

The cost of property, plant and equipment includes costs directly attributable to the acquisition of the asset. The cost of self constructed assets includes the cost of materials and direct labour, and any other costs directly attributable to bringing the asset to a working condition for its intended use.

The gain or loss on disposal of an item of property, plant and equipment is determined as the difference between the sale proceeds less the carrying amount of the asset and costs of removal and is recognized in the statement of earning and comprehensive income when that asset is disposed.

Depreciation begins when an asset becomes available for use. Depreciation of property, plant and equipment is recognized in the statement of earnings and comprehensive income on a straight-line basis over the estimated useful life of each part or component of an item of property, plant and equipment. Land is not depreciated. Construction in progress assets are not depreciated until the project is complete and in service. The estimated useful lives of the various assets used in the calculation of depreciation are summarized below:

| | Straight-line method estimated life (in years) |
|---|---|
| Buildings | 25 |
| Substation Equipment | 25 |
| Overhead Distribution System | 45 |
| Underground Distribution System | 45 |
| Services | 60 |
| Line Transformers | 40 |
| Meters | 15 - 25 |
| Trucks and Equipment | 4 - 8 |
| Computer Equipment | 10 |
| Office Equipment | 10 |

**Contributions in aid of construction**
Contributions in aid of construction are contributions received from electricity customers to construct or acquire property, plant and equipment. The contributions are deferred and amortized into revenue on a straight-line basis at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

**Intangible Assets**
Computer software that is acquired or developed by the corporation which has finite useful lives, is measured at cost less accumulated amortization and accumulated impairment losses.

Goodwill arising on the acquisition of subsidiaries or on amalgamation is measured at cost and is not amortized.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. Half of a year's amortization is taken in the first year of service. Amortization and useful lives of intangible assets are reviewed at each reporting date. The estimated useful lives for intangibles assets are as follows:

| | |
|---|---|
| Computer software | 10 years |

**Customer deposits**
Customers may be required to post security to obtain electricity or other services. Deposits to be refunded to customers within the next fiscal year are classified as a current liability. Interest rates paid on customer deposits are based on the Bank of Canada prime business rate less 2%.

**Employee future benefits**

**a) Multi-employer pension plan**
The utility provides a pension plan for all its full-time employees through the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards and school boards. The Fund is a contributory defined benefit pension plan which is financed by equal contributions from participating employers and employees and by the investment earnings in the Fund. Plan assets and pension obligations are not segregated into separate accounts for each member entity. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members. In this case the utility and its employees could face the prospect of higher contributions until the funded status of the Fund is restored. The utility is only able to recover additional contribution amounts in distribution rates if increased contribution rates are factored into the utility's rebasing rate applications before the OEB.

The OMERS plan is accounted for as a defined contribution plan and the contributions are recognized as an employee benefit expense in the statement of earning and comprehensive income in the period that service is rendered by the employee.

**b) Post-employment benefits - other than pension**
The Company provides some of its retired employees with extended health benefits and life insurance. The extended health benefits and life insurance plan is unfunded. The cost of these employee future benefit is recognized in the period in which the employees render the services.

The accrued benefit obligation and any current service costs are actuarially determined using the projected unit credit method and are based on assumptions that reflect management's best estimate of future salary levels, retirement ages of employees, health care costs and other actuarial factors. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses. Any actuarial gains(losses) will require a remeasurement of the net defined benefit liability or asset and will be recognized as other comprehensive income or loss in the year that it is known.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at December 31, 2013.

**Payments-In-Lieu of corporate taxes (PILS)**
The Company is a Municipal Electricity Utility for the purposes of the PILS regime contained in the Electricity Act, 1998 and is thereby exempt from tax under the Canadian Income Tax Act. It is required to make annual PILS payments to the Ontario Electricity Financial Corporation that are effectively equal to the tax that would be payable under the Canadian Income Tax Act .

The provision of PILS is comprised of current and deferred tax and is recognized directly in net income except to the extent that it relates to items recognized directly in equity or regulatory deferral accounts. Current PILS are recognized on the taxable income or loss for the current year plus any adjustment in respect of previous years. Current PILS are determined using tax rates and tax laws that have been enacted or substantively enacted by the year end date.

Deferred tax assets and liabilities are recognized where the carrying amount of an asset or liability differs from its tax base. The deferred tax asset or liability is measured at the amount expected to be recovered or paid using tax rates and tax laws that have been enacted or substantively enacted by year end and are expected to apply when the deferred tax asset/liability is settled.

Recognition of deferred tax assets for unused tax losses is restricted to those instances where it is probable that future taxable net income will be available against which the deferred tax asset can be utilized.

Management reassesses both recognized and unrecognized deferred tax assets at the end of each reporting period.

**Impairment of non-financial assets**
The carrying amount of the Utility's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the assets's recoverable amount is estimated. Goodwill and intangible assets with indefinite lives are tested annually for impairment and when circumstances indicate that the carrying value may be impaired. An impairment loss is recognized if the carrying amount of an asset exceeds its recoverable amounts.

**Future accounting pronouncements**
A number of new standards, amendments and interpretations have been published by the International Accounting Standards Board (IASB) but are not yet effective and have not been adopted early by the utility.

Information on new standards, amendments and interpretations that are expected to be relevant to the corporation's financial statements is provided below:

**IFRS 9 - financial instruments**
IFRS 9 amends the guidance on classification and measurement of financial instruments and replaces *IFRS 39 - Financial Instruments - Recognition and Measurement.* The new standard includes a new model for measuring impairment and carries forward the guidance in IFRS 39 related to the recognition and derecognition of financial instruments. The standard is effective January 1, 2018. The utility is in the process of assessing the impact of this new standard.

**IFRS 15 - revenue from contracts with customers**
IFRS 15 replaces all revenue recognition guidance and contains a single model that applies to contracts with customers and may impact the timing and amount of revenue recognized. The standard is effective January 1, 2018. The utility is in the process of assessing the impact of this new standard.

## 5. SEASONALITY

The corporation's operations are affected by seasonal weather changes. The corporation's revenues tend to be higher in the first and third quarter of the year as a result of higher energy consumption for winter heating in the first quarter and air conditioning and cooling in the third quarter. The volume of electricity consumed by customers during any period is governed by events largely outside of the corporation's control (principally, sustained periods of hot or cold weather which increases the consumption of electricity, and sustained periods of moderate weather which decreases the consumption of electricity).

## 6. ACCOUNTS RECEIVABLE

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Trade receivables | $ **982,087** | $ 732,148 |
| Other miscellaneous receivables | **364,205** | 90,640 |
| | **1,346,292** | 822,788 |
| Less: allowance for doubtful accounts (Note 19) | **(15,000)** | (10,902) |
| | $ **1,331,292** | $ 811,886 |

## 7. REGULATORY BALANCES

Debit balances consist of the following:

| | January 1, 2016 | Balances arising in the period | Recovery | Carrying Charges | December 31, 2016 |
|---|---|---|---|---|---|
| Settlement variances | $ 133,680 | $ (25,896) | $ (263,753) | $ (1,062) | $ **(157,031)** |
| Stranded meters | 74,080 | (44,422) | - | 616 | **30,274** |
| Extraordinary event | 183,296 | (102,943) | - | 1,318 | **81,671** |
| RARA - Sept 2012 | 3,251 | - | (3,251) | - | - |
| RARA - May 2015 | - | (159,934) | 268,987 | 1,704 | **110,757** |
| | $ 394,307 | $ (333,195) | $ 1,983 | $ 2,576 | $ **65,671** |

| | January 1, 2015 | Balances arising in the period | Recovery | Carrying Charges | December 31, 2015 |
|---|---|---|---|---|---|
| Settlement variances | $ 259,907 | $ (128,928) | $ - | $ 2,701 | $ 133,680 |
| Stranded meters | 116,953 | (44,016) | - | 1,143 | 74,080 |
| Extraordinary event | 282,712 | 2,682 | (102,098) | - | 183,296 |
| RARA - Sept 2012 | 3,618 | - | (367) | - | 3,251 |
| RARA - May 2014 | 161,011 | - | (181,800) | 271 | (20,518) |
| | $ 824,201 | $ (170,262) | $ (284,265) | $ 4,115 | $ 373,789 |

Credit balances consist of the following:

| | January 1, 2016 | Balances arising in the period | Recovery | Carrying Charges | December 31, 2016 |
|---|---|---|---|---|---|
| IFRS Transition | $ 36,254 | $ (36,254) | $ - | $ - | $ - |
| RARA - 2014 | 20,518 | - | - | - | **20,518** |
| Other | 185 | 1,214 | 961 | - | **2,360** |
| | $ 56,957 | $ (35,040) | $ 961 | $ - | $ **22,878** |

| | January 1, 2015 | Balances arising in the period | Recovery | Carrying Charges | December 31, 2015 |
|---|---|---|---|---|---|
| IFRS transition | $ 72,507 | $ (36,253) | $ - | $ - | $ 36,254 |
| Other | (961) | 1,152 | - | (6) | 185 |
| | $ 71,546 | $ (35,101) | $ - | $ (6) | $ 36,439 |

The following provides a summary of approved recovery periods for the variance noted above:

| | |
|---|---|
| Stranded meters | 4 years beginning September 2013 |
| Extraordinary event | 4 years beginning September 2013 |
| RARA - May 2012 | one year beginning September 2013 |
| RARA - May 2014 | one year beginning May 2014 |
| RARA - May 2015 | one year beginning May 2016 |
| IFRS transition variance | 4 years beginning September 2013 |

The "Balances arising in the period" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery" column consists of amount collected through rate riders .

**Settlement variances**
The variance represents the difference between the amount charged by the utility to its customers based on regulated rates and the corresponding costs incurred by the company for electricity and non-competitive electricity charges incurred by the utility. The utility has deferred the difference between the costs incurred and the related recoveries in accordance with the criteria included in the accounting principles prescribed by the OEB. The variance primarily consist of service charges, non-competitive electricity charges and the global adjustment. The variance will be recovered in future billing periods and through future hydro rates as approved by the Ontario Energy Board.

Interest is added monthly, calculated and recorded using simple interest at a prescribed rate on the carrying value to compensate the utility for the timing difference. The offsetting credit/debit is recorded as interest income/expense.

**Stranded meters**
This variance account represents the net book value of mechanical meters that were replaced by smart meters less amounts recovered via an approved rate rider that is effective September 1, 2013 to August 31, 2017.

**Extraordinary event costs**
In August 2011, the Town of Goderich was hit by an F3 tornado. This storm resulted in significant damage to the utility's distribution system. Under regulatory procedures set by the OEB, costs related to an extraordinary event may be considered for recovery if the event meets several criteria.

The utility applied for recovery of the expenditures through the cost of service rate rate process and a rate rider was approved that is effective from September 1, 2013 to August 31, 2017.

The variance balance consists of the costs incurred less recoveries via rider plus carrying charges accrued annually on the net uncollected principal balance.

**IFRS transition**
This regulatory balance relates to the difference arising from accounting policy changes for property, plant and equipment and intangible assets due to transition from Canadian GAAP to IFRS and is primarily due to useful life changes as part of componentization. This balance is reduced annually by $36,254 for a four year period beginning in 2013 with the amount charged against depreciation expense.

**Regulatory Asset/Liability Recovery Account (RARA)**
The RARA consists of balances of regulatory assets and regulatory liabilities that have been approved for disposition through Ontario Energy Board approved rate riders. The RARA is subject to carrying charges using rates approved by the Ontario Energy Board and calculated monthly using the simple interest method. Revenues collected via these specific distribution rate riders are allocated to the RARA as they are intended to offset or recover the approved amounts.

Any over/under recovery of these approved amounts will be factored into future rate approvals.

## 8. PROPERTY, PLANT AND EQUIPMENT

(a) Cost or deemed cost

| | Balance at January 1, 2015 | Additions | Transfers | Disposals | Balance at December 31, 2015 |
|---|---|---|---|---|---|
| Land | $ 21,747 | $ - | $ - | $ - | **$ 21,747** |
| Buildings | 43,065 | - | - | - | **43,065** |
| Substation equipment | 73,138 | - | - | - | **73,138** |
| Overhead distribution | 2,933,940 | 40,373 | 318,948 | (2,492) | **3,290,769** |
| Underground distribution | 1,765,134 | 49,510 | 200,070 | - | **2,014,714** |
| Services | 353,296 | 41,949 | - | - | **395,245** |
| Line transformers | 1,395,767 | 56,380 | 279,225 | (15,310) | **1,716,062** |
| Meters | 657,613 | 15,368 | - | - | **672,981** |
| Trucks and equipment | 665,293 | 46,208 | - | - | **711,501** |
| Leasehold improvements | - | 8,560 | - | - | **8,560** |
| Computer equipment | 28,407 | - | - | - | **28,407** |
| Office equipment | 6,550 | 558 | - | - | **7,108** |
| Construction in progress | 808,597 | 434,746 | (798,243) | - | **445,100** |
| Major parts and supplies | 581,220 | - | (100,374) | - | **480,846** |
| | $ 9,333,767 | $ 693,652 | $ (100,374) | $ (17,802) | **$ 9,909,243** |

| | Balance at January 1, 2016 | Additions | Transfers | Disposals | Balance at December 31, 2016 |
|---|---|---|---|---|---|
| Land | $ 21,747 | $ - | $ - | $ - | **$ 21,747** |
| Buildings | 43,065 | - | - | - | **43,065** |
| Substation equipment | 73,138 | 6,643 | - | - | **79,781** |
| Overhead distribution | 3,290,769 | 321,394 | 225,601 | (13,301) | **3,824,463** |
| Underground distribution | 2,014,714 | 240,835 | 82,832 | - | **2,338,381** |
| Services | 395,245 | 65,066 | 24,109 | - | **484,420** |
| Line transformers | 1,716,062 | 111,446 | 54,381 | (32,435) | **1,849,454** |
| Meters | 672,981 | 52,234 | 11,163 | - | **736,378** |
| Trucks and equipment | 711,501 | 27,855 | - | - | **739,356** |
| Leasehold improvement | 8,560 | - | - | - | **8,560** |
| Computer equipment | 28,407 | 4,532 | - | - | **32,939** |
| Office equipment | 7,108 | - | - | - | **7,108** |
| Construction in progress | 445,100 | 58,019 | (398,086) | - | **105,033** |
| Major parts and supplies | 480,846 | - | (73,589) | - | **407,257** |
| | $ 9,909,243 | $ 888,024 | $ (73,589) | $ (45,736) | **$ 10,677,942** |

(b) Accumulated depreciation

| | Balance at January 1, 2015 | Amortization | Impairment Loss | Reversals | Balance at December 31, 2015 |
|---|---|---|---|---|---|
| Buildings | $ 3,240 | $ 3,237 | $ - | $ - | $ **6,477** |
| Substation equipment | 6,090 | 6,090 | - | - | **12,180** |
| Overhead distribution | 76,601 | 83,380 | - | (133) | **159,848** |
| Underground distribution | 48,113 | 50,141 | - | - | **98,254** |
| Services | 7,818 | 7,145 | - | - | **14,963** |
| Line transformers | 35,411 | 57,360 | - | (1,623) | **91,148** |
| Meters | 47,900 | 50,376 | - | - | **98,276** |
| Trucks and equipment | 77,682 | 101,812 | - | - | **179,494** |
| Leasehold improvements | 214 | - | - | - | **214** |
| Computer equipment | 4,587 | 6,577 | - | - | **11,164** |
| Office equipment | 327 | 684 | - | - | **1,011** |
| | $ 307,983 | $ 366,802 | $ - | $ (1,756) | $ **673,029** |

| | Balance at January 1, 2016 | Amortization | Impairment Loss | Reversals | Balance at December 31, 2016 |
|---|---|---|---|---|---|
| Buildings | $ 6,477 | $ 3,237 | $ - | $ - | $ **9,714** |
| Substation equipment | 12,180 | 6,223 | - | - | **18,403** |
| Overhead distribution | 159,848 | 91,009 | - | (862) | **249,995** |
| Underground distribution | 98,254 | 56,506 | - | - | **154,760** |
| Services | 14,963 | 8,238 | - | - | **23,201** |
| Line transformers | 91,148 | 62,224 | - | (2,365) | **151,007** |
| Meters | 98,276 | 53,002 | - | - | **151,278** |
| Trucks and equipment | 179,494 | 103,988 | - | - | **283,482** |
| Leasehold improvement | 214 | 428 | - | - | **642** |
| Computer equipment | 11,164 | 4,152 | - | - | **15,316** |
| Office equipment | 1,011 | 711 | - | - | **1,722** |
| | $ 673,029 | $ 389,718 | $ - | $ (3,227) | $ **1,059,520** |

(c) Carrying amounts

| | **2016** | 2015 |
|---|---|---|
| Land | $ **21,747** | $ 21,747 |
| Buildings | **33,351** | 36,588 |
| Substation equipment | **61,378** | 60,958 |
| Overhead distribution | **3,574,468** | 3,130,921 |
| Underground distribution | **2,183,621** | 1,916,460 |
| Services | **461,219** | 380,282 |
| Line transformers | **1,698,447** | 1,624,914 |
| Meters | **585,100** | 574,705 |
| Trucks and equipment | **455,874** | 532,007 |
| Leasehold improvements | **7,918** | 8,346 |
| Computer equipment | **17,623** | 17,243 |
| Office equipment | **5,386** | 6,097 |
| Construction in progress | **105,033** | 445,100 |
| Major parts and supplies | **407,257** | 480,846 |
| | $ **9,618,422** | $ 9,236,214 |

## 9. INTANGIBLES

| | Computer Software | Goodwill | Total |
|---|---|---|---|
| **Cost** | | | |
| January 1, 2015 | $ 57,479 | $ 68,119 | $ 125,598 |
| Additions | 36,555 | - | 36,555 |
| December 31, 2015 | 94,034 | 68,119 | 162,153 |
| Additions | - | - | - |
| December 31, 2016 | $ 94,034 | $ 68,119 | $ 162,153 |
| **Accumulated Amortization** | | | |
| January 1, 2015 | $ 10,310 | $ - | $ 10,310 |
| Amortization | 13,690 | - | 13,690 |
| December 31, 2015 | 24,000 | - | 24,000 |
| Amortization | 13,691 | - | 13,691 |
| December 31, 2016 | $ 37,691 | $ - | $ 37,691 |
| **Carrying amounts** | | | |
| January 1, 2015 | $ 47,169 | $ 68,119 | $ 115,288 |
| December 31, 2015 | $ 70,034 | $ 68,119 | $ 138,153 |
| December 31, 2016 | $ 56,343 | $ 68,119 | $ 124,462 |

## 10. ACCOUNTS PAYABLE AND ACCRUALS

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Trade payables | **$ 1,883,288** | $ 1,490,606 |
| Accrued liabilities | **85,532** | 85,637 |
| Government remittances | **(220)** | 12,566 |
| | **$ 1,968,600** | $ 1,588,809 |

## 11. CONTRIBUTIONS IN AID OF CONSTRUCTION

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Deferred contributions, beginning of year | **$ 311,168** | $ 271,231 |
| Contributions in aid of construction received | **122,777** | 46,777 |
| Contributions in aid of construction recognized as revenue | **(8,899)** | (6,840) |
| Deferred contributions, end of year | **$ 425,046** | $ 311,168 |

## 12. TOWN OF GODERICH DEMAND LOAN

The demand loan bears interest at prime plus 1% and secured by a general security interest over all present and future assets.

## 13. BANK LOANS

| | **2016** | 2015 |
|---|---|---|
| Bank loan bearing interest at prime plus 0.4% annually; due February 2018; repayable with monthly payments of $7,072 plus interest; secured by a general security agreement over all property | $ **1,457,124** | $ 1,541,800 |
| Bank loan bearing interest at prime plus 0.4% annually; due December 2017; repayable with monthly payments of $1,571 plus interest; secured by a general security agreement over all property | **571,816** | 377,000 |
| Bank loan bearing interest at prime plus 0.4% annually; due February 2018; repayable with monthly payments of $4,050 plus interest; secured by a general security agreement over all property | **222,550** | 271,150 |
| | **2,251,490** | 2,189,950 |
| Current portion | **705,286** | 152,322 |
| | $ **1,546,204** | $ 2,037,628 |

The approximate principal payments due are as follows:

| | |
|---|---|
| 2016 | $ 705,286 |
| 2017 | 1,546,204 |
| | $ 2,251,490 |

## 14. NOTE PAYABLE

The note is payable to the shareholder of the company, is due upon demand and bears interest at 7.25% per annum. The note is secured by a general security agreement over all of the Company's assets. The note has been classified as long-term because it is not the intent of the shareholder to demand repayment within the next year. Interest expense for the year is **$70,048** (2015 - $70,648).

## 15. EMPLOYEE FUTURE BENEFITS

### Pension

The assets and pension obligations of this multi-employer plan are not segregated into separate accounts for each member entity. As at December 31, 2015, the plan was **2016 - 93.4%** (2015 - 91.5%) funded. The plan's most recent actuarial valuation was performed at December 31, 2015. The Primary Plan is reporting actuarial liabilities of **$86.9** billion (2015 - $81.9 billion) and actuarial net assets available for benefits of **$81.2** billion (2015 - $74.9 billion) creating an actuarial deficit of **$5.7** billion (2015 - $7 billion). Total contributions for all participating employers and employees into the Primary Plan for 2016 was approximately **$3.9** billion (2015 - $3.8 billion). The total contributions of the utility and its employees for 2016 was **$119,107** (2015 - $113,458). The utility expects to contribute approximately $119,000 in 2017.

### Post employment medical and life insurance plan

The utility provides post-retirement life insurance benefits to all retirees and extended health, dental and vision benefits until age of 65 for employees meeting specific age and service requirements. This benefit plan is unfunded. The utility has recorded its share of the defined benefit costs and the related liability in these financial statements based on calculations made by an actuary. The most recent actuarial valuation was performed as at January 1, 2013 and provides the basis for the reported accrued benefit liability and expenses for 2014 and 2015. the data presented for 2016 is based on values estimated to be consistent with the actuarial report pending an updated valuation.

The plan is exposed to several risks including interest rate risk, longevity risk and health care benefit cost risk. Changes in interest rates used to discount the liability, changes to assumptions related to the life span of its employees and changes in the costs of providing the health care benefits will all impact the assumptions used in the actuarial valuation of the accrued benefit liability.

| **Defined benefit obligation** | **2016** | 2015 |
|---|---|---|
| Defined benefit obligation, beginning of year | $ **303,457** | $ 314,273 |
| Amounts recognized in net earnings | | |
| Current service cost | **13,916** | 13,916 |
| Interest cost on obligation | **5,010** | 5,010 |
| Benefit payments | **(30,422)** | (29,742) |
| Defined benefit obligation, end of year | $ **291,961** | $ 303,457 |

| **Significant assumptions** | **2016** | 2015 |
|---|---|---|
| Discount rate used in the calculation of the defined benefit obligation | **3.65 %** | 3.65 % |
| Rate of increase in dental costs | **4.60 %** | 4.60 % |
| Rate of increase in health benefits costs | **6.70 %** | 6.70 % |
| Rate of compensation increase | **-** | - |
| Age of retirement | **60** | 60 |

**Sensitivity analysis (in thousands)**

| | **As reported** | **1% increase** | **1% decrease** |
|---|---|---|---|
| Health and dental cost | 386 | 399 | 375 |

Retirement age change to 58 from 60 would increase the obligation from $386 to $414.

## 16. CREDIT FACILITIES

The company has a revolving demand facility with an authorized limit of $1,000,000 available under the credit facility with a Canadian chartered bank. The line of credit bears interest at the bank's prime rate, calculated and payable monthly. The facility is secured by a general security agreement covering all company assets excluding real property. A priority agreement has also been obtained in favour of the bank over the Town of Goderich. The Company has not drawn on this facility as at December 31, 2016.

The company has arranged a second credit facility which is available by way of letters of credit or letter of guarantee. This facility is a revolving demand facility with an authorized limit of $583,000. The company has provided the letter of credit described below by using this facility. Fees of 0.75% are paid quarterly.

The company has arranged a third credit facility. This facility is a non-revolving term facility with an authorized limit of $1,000,000. The company has drawn **$571,816** (2015 - $377,000) from this facility by way of a term loan to finance a portion of its investment in distribution assets and equipment. The terms of the loan are described in Note 13.

**Letter of credit**
The company has provided prudentials, in the form of an irrevocable letter of credit, in the amount of **$582,133** (2015 - $582,133) in favour of the Independent Electricity System Operator. The prudentials serves as security for power purchased from the Independent Electricity Market Operator.

## 17. OTHER REVENUE (EXPENSES)

| | 2016 | 2015 |
|---|---|---|
| Miscellaneous service revenue | $ **114,600** | $ 45,033 |
| Conservation funding | **80,252** | 299,712 |
| Water and sewer collection fees | **43,100** | 42,580 |
| Specific service charges | **21,480** | 22,655 |
| Rental from electric property | **16,599** | 16,599 |
| Bank interest | **11,321** | 10,659 |
| SSS admin | **11,084** | 10,942 |
| Late payment charges | **11,009** | 8,884 |
| Service transaction requests | **3,640** | 4,420 |
| Retail service charges | **2,364** | 3,137 |
| Feed in tariff | **(4,336)** | - |
| Gain (loss) on disposal of property, plant and equipment | **(42,510)** | (16,046) |
| Conservation expenses | **(85,845)** | (299,712) |
| | $ **182,758** | $ 148,863 |

## 18. AMORTIZATION EXPENSE

| | 2016 | 2015 |
|---|---|---|
| Property, plant and equipment | $ **302,461** | $ 279,759 |
| Intangibles | **13,690** | 13,690 |
| Transition variance | **(36,254)** | (36,253) |
| | **279,897** | 257,196 |
| Vehicles - allocated to other accounts | **87,256** | 87,256 |
| | $ **367,153** | $ 344,452 |

## 19. BAD DEBTS EXPENSE

Bad debt expense is included in Billing and Collection expense on the Statement of Earnings and Comprehensive Income and includes the following activity for the year:

| | 2016 | 2015 |
|---|---|---|
| Write-offs during the year | $ **16,969** | $ 11,113 |
| Recoveries during the year | **(1,196)** | (1,015) |
| Opening allowance | **(10,902)** | (10,000) |
| Closing allowance | **15,000** | 10,902 |
| | $ **19,871** | $ 11,000 |

## 20. SALARIES AND BENEFITS EXPENDITURES

The utility charges salaries and benefits expense to each function based on time spent. The costs were allocated as follows:

| | 2016 | 2015 |
|---|---|---|
| Operations and maintenance | $ 289,162 | $ 323,128 |
| Capital asset construction and work in progress | 249,956 | 168,950 |
| Administration and general | 168,654 | 167,904 |
| Billing and collecting | 160,696 | 173,632 |
| Streetlight maintenance services | 7,744 | 13,545 |
| | $ 876,212 | $ 847,159 |

## 21. FINANCING INCOME AND CHARGES

| | 2016 | 2015 |
|---|---|---|
| **Finance income** | | |
| Carrying charges on regulatory deferrals | $ 3,596 | $ 6,803 |
| **Finance charges** | | |
| Demand loan | $ 74,002 | $ 75,488 |
| Note payable | 70,648 | 70,648 |
| Bank loan | 65,941 | 60,497 |
| Other | 11,896 | 11,909 |
| | $ 222,487 | $ 218,542 |

## 22. PAYMENTS IN LIEU OF CORPORATE TAXES

The provision for payment in lieu of income taxes recognized in income is as follows:

| | 2016 | 2015 |
|---|---|---|
| **Current tax** | | |
| Based on current taxable income | $ 23,526 | $ 25,500 |
| **Deferred tax** | | |
| Origination and reversal of timing differences | 22,970 | 22,060 |
| | $ 46,496 | $ 47,560 |

The provision for PILS differs from the amount that would have been recorded using the combined Canadian federal and provincial statutory income tax rate. Statutory Canadian federal and provincial tax rates for the current year comprise 15% (2015 - 15%) for federal corporate tax and 11% (2015 - 11.5%) for corporate tax in Ontario. For corporations with assets of less than $15 million the statutory rate is reduced on the first $500,000 of taxable income to 15% The reconciliation between the statutory and effective rates is provided as follows:

| | 2016 | 2015 |
|---|---|---|
| Income before provision for PILS | $ **439,139** | $ 273,337 |
| Statutory Canadian federal and provincial income tax rate | **15%** | 15.5% |
| Expected tax provision on income at statutory rates | $ **65,871** | $ 42,367 |
| Increase (decrease) in income taxes resulting from: | | |
| Capital cost allowance in excess of amortization | **(51,322)** | (40,808) |
| Other | **8,977** | 23,941 |
| Provision for PILS | $ **23,526** | $ 25,500 |

**Deferred payments in lieu of income taxes**

Significant components of the Utility's deferred payments in lieu balances are as follows:

| **Deferred PILs liability** | 2016 | 2015 |
|---|---|---|
| Property, plant and equipment and intangibles | $ **93,592** | $ 50,373 |
| Other | **(6,389)** | 17,102 |
| Employee benefits | **(43,794)** | (47,036) |
| | $ **43,409** | $ 20,439 |

## 23. SHARE CAPITAL

| | 2016 | 2015 |
|---|---|---|
| Authorized share capital | | |
| Unlimited number of common shares with no par value | | |
| Issued share capital | | |
| 1 common share; fully paid | $ **3,410,092** | $ 3,410,092 |

There has been no movement in share capital during 2016 or 2015.

## 24. DIVIDENDS

Dividends of **$175,000** (2015 - $100,000) were declared. The amount of dividends declared each year is at the discretion of the Board of Directors.

## 25. SUPPLEMENTAL CASH FLOW INFORMATION

| | 2016 | 2015 |
|---|---|---|
| Change in non-cash operating working capital | | |
| Increase in receivables | $ **(519,406)** | $ (404,804) |
| Decrease (increase) in unbilled revenue | **(86,942)** | (85,119) |
| Increase (decrease) in deferred revenue | **-** | (4,932) |
| Increase (decrease) in payables and accruals | **379,791** | 37,558 |
| Increase in future income tax asset/liability | **22,970** | 22,060 |
| Decrease in payments-in-lieu of corporate taxes receivable/payable | **(4,817)** | 18,905 |
| | $ **(208,404)** | $ (416,332) |

## 26. RELATED PARTY TRANSACTIONS

West Coast Huron Energy is wholly owned by the Corporation of the Town of Goderich. Since the parent of the utility is a local government, the utility is exempt from some the general disclosure requirements of IAS 24 related to its transactions with its parent company.

The following summarizes the utility's related party transactions for the year. The transactions occurred in the normal course of operations and are measured at the exchange amount which is the amount of consideration established and agreed to by the related parties. The exchange value approximates the arm's length value of the sales or services provided.

| | 2016 | 2015 |
|---|---|---|
| **Revenues** | | |
| Streetlight hydro | $ **155,220** | $ 250,629 |
| Water and sewer collection fees | **43,100** | 42,580 |
| Streetlight maintenance | **9,577** | 28,407 |
| **Expenses** | | |
| Dividends | **175,000** | 100,000 |
| Interest on debt | **144,650** | 146,136 |
| Rent | **106,439** | 104,352 |
| Administration and services fees | **79,000** | 79,000 |
| Health and Safety services | **12,000** | 12,000 |
| Environmental services | **28,037** | - |

Streetlight revenues were charged to the shareholder based on rates approved by the OEB consistent with rates determined for all other customers.

During the year, the directors of the utility received compensation in the amount of **$42,825** (2015 - $45,597).

At year end, the utility owed the Corporation of the Town of Goderich the following:

| | 2016 | 2015 |
|---|---|---|
| Water and sewer revenue, net of fees | $ **305,905** | $ 292,614 |
| Dividends | **175,000** | 100,000 |
| Health and safety services fees | **12,000** | 12,000 |
| Environmental services fees | **28,037** | - |

## 27. COMMITMENT

The Company has the following obligations under operating leases for operations premises and office space:

| | |
|---|---|
| 2016 | $ 106,100 |
| 2017 | $ 106,100 |
| 2018 | $ 106,100 |
| 2019 | $ 106,100 |
| 2020 | $ 106,100 |

The operating leases have a 20 year term. The lease for the operations premise expires in 2033 and the office space lease term expires in 2030.

## 28. CAPITAL DISCLOSURES

The Company's capital structure consists of its share capital, retained earnings and the accumulated balance in other comprehensive income as well as the long-term note payable to its shareholder. The Company's main objectives when managing its capital are as follows:

- deliver a reasonable return on the investments of its shareholder;
- to ensure adequate liquidity to maintain and improve its distributions system and meet it financial obligations;
- to align its capital structure for regulated activities with the debt to equity structure deemed by the Ontario Energy Board

The Company's note payable agreement does not contain any covenants.

## 29. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

### Fair value of financial instruments

The Company's financial instruments include cash, bank indebtedness, receivables, unbilled revenue, accounts payables, accrued liabilities, dividends payable and customer deposits. The carrying value of these instruments approximates their fair value due to their immediate or short-term maturity.

Financial instruments also include the note payable with terms as disclosed in Note 12 and 14 . The fair value has not been determined or disclosed as the cash flows related to this liability are uncertain.

The estimated fair value of long-term debt is **$1,546,204** (2015 - $2,037,628). The fair value is calculated based on the present value of the future principal and interest cash flows, discounted at the current rate of interest at the reporting date.

Fair value estimates are subjective by nature and contain uncertainties and matters of significant judgement. The estimates are based on market prices and information available at the time and may not necessarily be indicative of actual amounts the Utility will receive or incur in actual market transactions.

### Determination of fair value

Financial instruments which are disclosed at fair value are to be classified using a three- level hierarchy. Each level reflects the inputs used to measure the fair values disclosed for financial liability as follows:

Level 1: inputs are unadjusted quoted prices of identical instruments in active markets;

Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability either directly or indirectly; and,

Level 3: inputs for the liabilities that are not based on observable market data (unobservable inputs).

The Utility's fair value hierarchy is classified as Level 2 for long-term debt. The classification for disclosure purposes has been determined using the discounted cash flow model based on the contractual terms of the debt instrument discounted using an appropriate market rate of interest.

**Financial risk management**
As part of its operations, the company carries out transactions that expose it to financial risks such as credit, liquidity and market risks. The following is a discussion of risks and mitigation strategies identified by management. However, the risks described below are not exhaustive of all the risks nor will the mitigation strategies eliminate the utility's exposure to all risks listed.

**Credit risk**
The risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation. The maximum credit exposure is limited to the carrying amount of cash and receivables and unbilled revenue presented on the balance sheet.

The Company limits its credit risk related to cash by placing its cash with a high quality financial institution.

The Company is exposed to credit risk related to accounts receivable arising from its electricity and service revenue. Exposure to credit risk from its accounts receivable is limited due to the corporation's diverse customer base. As of December 31, 2016 the utility has approximately 3,840 customers. In addition, the Company holds customer and construction deposits which are recognized as liabilities on the balance sheet. The Company does not have material customer accounts receivable balances greater than 90 days outstanding. As a result, the Company believes that its accounts receivable represent a low credit risk.

The utility has one customer that generated revenue of **$1,411,896** (2015 - $1,294,689) which represents more than 10% of total revenue for the year.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts. The balance of the allowance for impairment as at December 31, 2016 is **$15,000** (2015 - $10,902). An impairment loss of **$19,871** (2015 - $11,000) has been recognized in net earnings.

Accounts receivable aging analysis is as follows

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Outstanding for not more than 30 days | **$ 962,787** | $ 701,194 |
| Outstanding for more than 30 days and not more than 90 days | **4,180** | 11,441 |
| Outstanding for more than 90 days | **15,120** | 19,513 |
| | **982,087** | 732,148 |
| Unbilled revenue | **1,248,924** | 1,161,982 |
| | **$ 2,231,011** | $ 1,894,130 |

Unbilled revenue represents amounts for which the Utility has a contractual right to receive cash through future billings but are unbilled at year end. Unbilled revenue is considered to be current and no allowance for doubtful accounts has been provided.

**Market risk**

Market risk refers to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Utility does not have any direct exposure to commodity or foreign exchange risk.

The Utility manages its exposure to interest rate risk by issuing long-term fixed rate debt in the form of bank loans and promissory note. It also ensures that all payment obligations can be met through proper capital planning.

The Utility has a revolving demand credit facility which it can utilize for working capital and/or capital expenditure purposes. Such short term borrowings may expose the Utility to fluctuations in short-term interest rates. The Town of Goderich demand note payable is also at a variable rate further exposing the entity to short-term rate fluctuations.

A sensitivity analysis was conducted to determine the impact of a 1% increase in the prime lending rate. This interest rate variation with all other variable held constant would result in an estimated increase of **$41,753** (2015 - $41,900) in annual finance cost.

**Liquidity risk**

Liquidity risk is the risk that the company will encounter difficulty in meeting obligations associated with financial liabilities as they come due. The Company monitors and manages its liquidity risk to ensure, as far as possible, access to sufficient funds to meet operational and investing requirements. It monitors its cash balances to ensure sufficient levels of liquidity are on hand to meet its financial commitments as they come due while minimizing interest exposure.

Liquidity risk associated with financial commitments are as follows:

| | 0 - 3 mo | 3 mo - 1yr | 1 - 5yr | Thereafter | Total |
|---|---|---|---|---|---|
| Accounts payable | $ 1,968,600 | $ - | $ - | $ - | $ 1,968,600 |
| Dividends payable | 175,000 | - | - | - | 175,000 |
| Customer deposits | - | 50,000 | 93,193 | - | 143,193 |
| Long-term debt | 38,079 | 667,207 | 1,546,204 | - | 2,251,490 |
| | $ 2,181,679 | $ 717,207 | $ 1,639,397 | $ - | $ 4,538,283 |

## 30. INSURANCE

The Company holds insurance with major insurers at appropriate types and levels as determined by management. It is a member of the Municipal Electricity Association Reciprocal Insurance Exchange (MEARIE) for its liability coverage. This reciprocal insurance exchange is formed to exchange reciprocal contracts of indemnity or inter-insurance among the members of the group. All members of the pool are subject to assessment for losses experienced by the pool, for the years in which they were members. As at December 31, 2016, the Utility has not been made aware of any assessment for losses. Insurance premiums are charged to each member as a fee per thousands of dollars of service revenue with an adjustment to reflect the member's claims experience. The coverage provided by this insurance is to a level of $20,000,000 per occurrence. The utility does not currently hold insurance coverage for its distribution assets.

# ATTACHMENT 10

## FINANCIAL STATEMENTS – WEST COAST HURON ENERGY - 2015

# West Coast Huron Energy Inc.
# Financial Statements
# December 31, 2015

CHARTERED PROFESSIONAL ACCOUNTANTS
Takalo & Burt

**Ronald E. Takalo, B.Math., CPA, CA**
**Ronald F. Burt, B. Comm., CPA, CA**

40 The Square
Goderich, Ontario
N7A 1M4
Tel: 519-524-2677
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## INDEPENDENT AUDITORS' REPORT

To the Shareholder of
West Coast Huron Energy Inc.

We have audited the accompanying financial statements of West Coast Huron Energy Inc., which comprise the balance sheet as at December 31, 2015, December 31, 2014 and January 1, 2014, and the statement of earnings and other comprehensive income and cash flows for the years ending December 31, 2015 and December 31, 2014 and a summary of significant accounting policies and other explanatory information.

**Management's Responsibility for the Financial Statements**
Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

**Auditors' Responsibility**
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**
In our opinion, these financial statements present fairly, in all material respects, the financial position of West Coast Huron Energy Inc. as at December 31, 2015, December 31, 2014 and January 1, 2014 and its operations and its cash flows for the years ended December 31, 2015 and December 31, 2014 in accordance with International Financial Reporting Standards.

Takalo & Burt

LICENSED PUBLIC ACCOUNTANTS
CHARTERED PROFESSIONAL ACCOUNTANTS
CHARTERED ACCOUNTANTS

Goderich, Ontario
April 26, 2016

## West Coast Huron Energy Inc.
## Statement of Earnings and Other Comprehensive Income

| For the year ended December 31 | 2015 | 2014 (expressed in CDN$) |
|---|---|---|
| **Revenue** | | |
| Sale of energy | **$ 10,081,745** | $ 9,511,677 |
| Distribution revenue | **2,348,941** | 2,386,460 |
| Regulatory adjustment to sale of energy | **415,305** | 432,060 |
| Other revenue (Note 17) | **148,863** | 222,832 |
| Contributions in aid of construction | **6,840** | 3,147 |
| | **13,001,694** | 12,556,176 |
| **Cost of power** | | |
| Power purchased | **10,081,745** | 9,511,677 |
| **Net distribution revenue** | **2,919,949** | 3,044,499 |
| **Expenditures** | | |
| Administration and general | **794,774** | 772,189 |
| Billing and collecting | **428,709** | 423,956 |
| Maintenance | **390,269** | 266,708 |
| Amortization (Note 18) | **257,196** | 212,036 |
| Operations | **140,160** | 208,223 |
| Community relations | **8,460** | 13,949 |
| | **2,019,568** | 1,897,061 |
| **Earnings from operations before the following** | **900,381** | 1,147,438 |
| Finance income (Note 21) | **6,803** | 18,692 |
| Finance charge (Note 21) | **(218,542)** | (204,987) |
| **Net earnings before payments-in-lieu of taxes and regulatory items** | **688,642** | 961,143 |
| Net movements in regulatory balances | **(415,305)** | (432,060) |
| **Net earnings before payment in lieu of taxes** | **273,337** | 529,083 |
| Payments-in-lieu of taxes (Note 22) | **25,500** | 27,952 |
| Future taxes (Note 22) | **22,060** | 71,550 |
| | **47,560** | 99,502 |
| **Net earnings for the year** | **225,777** | 429,581 |
| Other comprehensive income | - | - |
| **Total earnings and other comprehensive income for the year** | **$ 225,777** | $ 429,581 |

See accompanying notes to the financial statements

# West Coast Huron Energy Inc.
## Statement of Changes in Shareholder's Equity
**For the year ended December 31**

| | Capital Stock | Other Comprehensive income | Retained earnings |
|---|---|---|---|
| Balance as at January 1, 2014 | $ 3,410,092 | $ (89,250) | $ 1,932,302 |
| Total income and other comprehensive income for the year | - | - | 429,581 |
| Dividend | - | - | (125,000) |
| Balance as at December 31, 2014 | 3,410,092 | (89,250) | 2,236,883 |
| Total income and other comprehensive income for the year | - | - | 225,777 |
| Dividend | - | - | (100,000) |
| Balance as at December 31, 2015 | $ 3,410,092 | $ (89,250) | $ 2,362,660 |

See accompanying notes to the financial statements

## West Coast Huron Energy Inc.
## Balance Sheet

| | As at December 31, 2015 | As at December 31, 2014 | As at January 1, 2014 |
|---|---|---|---|
| **ASSETS** | | | |
| **Current** | | | |
| Cash | $ **1,611,038** | $ 1,474,960 | $ - |
| Receivables (Note 6) | **811,886** | 407,082 | 485,938 |
| Unbilled revenue | **1,161,982** | 1,076,863 | 1,144,515 |
| Payments-in-lieu of corporate taxes receivable | **8,739** | 27,644 | - |
| Prepaids | **10,510** | 10,510 | 10,510 |
| Total current assets | **3,604,155** | 2,997,059 | 1,640,963 |
| Property, plant and equipment - net (Note 8) | **9,236,214** | 9,025,998 | 8,115,819 |
| Goodwill | **68,119** | 68,119 | 68,119 |
| Intangibles (Note 9) | **70,034** | 47,169 | 57,479 |
| Future income tax asset (Note 22) | **-** | 1,621 | 73,171 |
| **Total assets** | **12,978,522** | 12,139,966 | 9,955,551 |
| Regulatory balances (Note 7) | **373,789** | 825,162 | 1,293,477 |
| **Total assets and regulatory balances** | $ **13,352,311** | $ 12,965,128 | $ 11,249,028 |
| **LIABILITIES** | | | |
| **Current** | | | |
| Bank indebtedness | $ - | $ - | $ 386,756 |
| Payables and accruals (Note 10) | **1,588,809** | 1,551,250 | 1,827,149 |
| Payments-in-lieu of corporate taxes payable | - | - | 17,731 |
| Deferred revenue | - | 4,932 | 106,237 |
| Town of Goderich demand loan (Note 12) | **2,000,000** | 2,000,000 | 2,000,000 |
| Dividends payable | **100,000** | 125,000 | - |
| Current portion of bank loan | **152,322** | 132,312 | - |
| Current portion of customer deposits | **50,000** | 50,000 | 50,000 |
| **Total current liabilities** | **3,891,131** | 3,863,494 | 4,387,873 |
| **Long-term** | | | |
| Note payable (Note 14) | **974,454** | 974,454 | 974,454 |
| Bank loans (Note 13) | **2,037,628** | 1,812,838 | - |
| Contributions in aid of construction (Note 11) | **311,168** | 271,231 | - |
| Post-employment benefits obligation (Note 15) | **303,457** | 314,273 | 329,069 |
| Customer deposits | **94,093** | 98,606 | 195,727 |
| | **3,720,800** | 3,471,402 | 1,499,250 |
| Future income taxes (Note 22) | **20,439** | - | - |
| **Total liabilities** | **7,632,370** | 7,334,896 | 5,887,123 |
| **SHAREHOLDER'S EQUITY** | | | |
| Share capital (Note 23) | **3,410,092** | 3,410,092 | 3,410,092 |
| Retained earnings | **2,362,660** | 2,236,883 | 1,932,302 |
| Other comprehensive income | **(89,250)** | (89,250) | (89,250) |
| **Total shareholder's equity** | **5,683,502** | 5,557,725 | 5,253,144 |
| **Total liabilities and shareholder's equity** | **13,315,872** | 12,892,621 | 11,140,267 |
| Regulatory balances (Note 7) | **36,439** | 72,507 | 108,761 |
| **Total liabilities, shareholder's equity and regulatory balances** | $ **13,352,311** | $ 12,965,128 | $ 11,249,028 |

**APPROVED ON BEHALF OF THE BOARD:**

[redacted] Director [redacted] Director

## West Coast Huron Energy Inc.
## Statement of Cash Flows

| For the year ended December 31 | 2015 | 2014 |
|---|---|---|
| **Operating activities** | | |
| Net earnings | **$ 225,777** | $ 429,581 |
| Adjustments for non-cash items | | |
| Amortization of property, plant and equipment and intangibles | **257,196** | 212,036 |
| Amortization of contributions in aid of construction | **(6,840)** | (3,147) |
| Loss (gain) on disposal of property, plant and equipment | **16,046** | (34,107) |
| Increase in post-employment benefits obligation | **(10,816)** | (14,796) |
| Non-cash adjustments to regulatory asset/liabilities | **36,254** | 36,254 |
| Change in non-cash working capital balances (Note 25) | **(441,332)** | (79,521) |
| Net cash provided by operating activities | **76,285** | 546,300 |
| **Financing activities** | | |
| Increase in bank loan | **244,800** | 1,945,150 |
| Dividends paid | **(100,000)** | (125,000) |
| Increase (decrease) in customer deposits | **(4,513)** | (97,121) |
| Net cash provided by financing activities | **140,287** | 1,723,029 |
| **Investing activities** | | |
| Purchase of property, plant and equipment | **(506,021)** | (1,153,631) |
| Purchase of intangibles | **(36,555)** | - |
| Decrease (increase) in regulatory assets/liabilities | **415,305** | 432,061 |
| Proceeds on disposal of property, plant and equipment | - | 39,579 |
| Proceeds of contributions in aid of construction | **46,777** | 274,378 |
| Net cash provided by investing activities | **(80,494)** | (407,613) |
| **Net increase in cash** | **136,078** | 1,861,716 |
| **Cash**, beginning of year | **1,474,960** | (386,756) |
| **Cash**, end of year | **$ 1,611,038** | $ 1,474,960 |
| **Cash consists of:** | | |
| Cash | **$ 1,611,038** | $ 1,474,960 |

## 1. NATURE OF BUSINESS

West Coast Huron Energy Inc. was incorporated on October 19, 1999 under the Business Corporations Act(Ontario) in accordance with the Electricity Act. The Corporation is a wholly owned subsidiary of the Corporation of the Town of Goderich and is domiciled in Canada. The address of the Corporation's registered office is 57 West Street, Goderich, Ontario.

The Town of Goderich passed a Bylaw transferring certain assets and liabilities of the Public Utilities Commission of the Town of Goderich Municipal Electrical Utility to this corporation. In exchange for these assets, the Town of Goderich received a promissory note and common shares.

The principal activity of the corporation is to distribute electricity to residents and businesses in the Town of Goderich under license issued by the Ontario Energy Board ("OEB"). The Company is regulated by the Ontario Energy Board ("OEB") and adjustments to the distribution and power rates require OEB approval.

## 2. BASIS OF PRESENTATION

### Statement of compliance

These financial statements are the first annual financial statements of the Corporation prepared in accordance with International Financial Reporting Standards (IFRS) and IFRS 1 *First-time Adoption of International Financial Reporting Standards* (IFRS 1) has been applied. An explanation of the impact on the reported financial position, financial performance and cashflows of the transition to IFRS has been provided in Note 31.

### Basis of measurement

The financial statements have been prepared on a historical cost basis.

### Presentation currency

The financial statements are presented in Canadian dollars, which is also the functional currency of the Corporation. All financial information has been rounded to the nearest dollar except when otherwise noted.

### Use of estimates and judgements

The preparation of financial statements in accordance with IFRS requires management to make estimates, assumptions and judgements that affect the application of accounting policies and the reported amounts and disclosures made in the financial statements. Actual results could differ from the current estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected.

Significant sources of estimation uncertainty include the following:

i) **Useful lives of depreciable assets**
Depreciation and amortization expense is based on estimates of the useful lives of property, plant and equipment and intangible assets. Management estimates the useful lives of its property, plant and equipment and intangible assets based on judgement, historical experience and an assets study conducted by an independent consulting firm on assets most commonly used in the distributors of electricity in Ontario at the request of the Ontario Energy Board.

ii) **Employee future benefits**
The cost of post employment medical and insurance benefits are determined using actuarial valuation. This valuation is complex and involves making numerous assumptions . The long-term nature, complexity and sensitivity of the valuation to changes in interest rates, post employment medical and insurance benefits assumptions makes the reported liability subject to uncertainty. Assumptions are reviewed annually and valuations are recalculated when any significant changes occur.

iii) **Other areas**
There are a number of other areas that require management to make estimates; these include accounts receivable, and income taxes. These amounts are reported based on amounts expected to be recovered/refunded and an appropriate allowance has been provided for estimated unrecoverable amounts based on management's best estimate.

## 3. REGULATION

The Ontario Energy Board has regulatory oversight powers over electricity matters in Ontario. The OEB issues distribution licences to all owners or operators of a distribution system in Ontario. This licence sets out requirements for regulatory accounting principles, the filing process for rate setting purposes as well as many other conditions for operation. The OEB has the authority to approve and fix rates charged for the transmission and distribution of electricity and thereby also to provide rate protection to electricity customers. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from IFRS for enterprises operating in a non-rate regulated environment.

The utility purchases electricity from the wholesale market administered by the Independent Electricity System Operator ("IESO") and recovers the costs of electricity and certain other costs in accordance with procedures mandated by the OEB.

The OEB's regulatory framework for electricity distributors typically regulates the electricity rates using a combination of detailed cost of service reviews and formulatic adjustments based on inflationary factors net of a productivity factor and efficiency factor as determined relative to other electricity distributors.

Operation of the utility in this regulated environment expose it to the following risks:

**Regulatory risk**
Regulatory risk is the risk that the Province and its regulatory, the OEB, could establish a regulatory regime that imposes conditions that restrict the utility from achieving an acceptable rate of return that supports the financial sustainability of its operations. All requests for changes in electricity distribution charges required the approval of the OEB.

**Recovery risk**
Regulatory developments in Ontario's electricity industry including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other allowable recoveries in the future. The corporation is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (a) to recover the forecasted operating costs including depreciation, income taxes and (b) to provide a fair and reasonable return on utility investment. Actual operating conditions may vary from the forecast and actual returns can differ from the approved returns.

## 4. SIGNIFICANT ACCOUNTING POLICIES

The financial statements are the representations of management prepared in accordance with IFRS. The accounting policies set out below have been applied consistently to all years presented in these financial statements and in preparing the opening IFRS balance sheet at January 1, 2014 for the purpose of the transition to IFRS unless otherwise indicated.

The financial statements reflect the following significant accounting policies:

### Revenue Recognition

**Electricity distribution and sale**
Revenue from the sale of energy and distribution of electricity are recorded on the basis of cyclical billings based on electricity usage and includes unbilled revenue accrued in respect of electricity delivered but not yet billed.
The utility is required to charge its customers for the following amounts ( all of which, other than distribution rates, represent a pass through to customers of amounts payable to third parties):

**Commodity charge**
The commodity charge represents the price of electricity consumed by customers and is passed through the IESO to operators of generating stations.

**Retail transmission rate**
The retail transmission rate represents the pass through of costs charged to the utility for the transmission of electricity from generating stations to local distribution networks.

**Wholesale market service charge**
The wholesale market service charge represents a pass through of various wholesale market support costs charged by the IESO.

**Distribution charge**
The distribution charge is designed to recover the costs incurred by the utility in delivering electricity to its customers, as well as the ability to earn the OEB allowed rate of return. The distribution charge is regulated by the OEB and generally consists of a fixed monthly charge and a usage-based (consumption) charge.

The difference between the amounts charged by the utility to its customers, based on regulated rates, and the corresponding commodity, retail transmission and wholesale market service costs billed by the IESO to the utility is recorded as a settlement variance. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the utility's balance sheet and within net movements in regulatory balances, on the utility's statement of earnings and comprehensive income.

**Other revenue**
Other revenue, which includes revenue from services ancillary to the distribution of electricity is recognized as the services are rendered.

Capital contributions received from electricity customers to construct or acquire property, plant and equipment for the purpose of connecting a customer to a network are recorded as contributions in aid of construction and amortized into revenue at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

**Financial assets - classified as loans and receivables**
These financial assets include cash and bank, accounts receivable and unbilled revenue. Collectibility of accounts receivable is reviewed by management on an ongoing basis. Amounts that are known to be uncollectible are written off. A provision for doubtful receivables is recorded when there is evidence that the utility will not be able to collect the amount due. The amount of the provision is recognized in the statement of earnings.

**Financial liabilities**
Accounts payable and accruals, customer deposits and long-term debt are classified as financial liabilities. These liabilities are measured at amortized cost.

**Cash and cash equivalents**
Cash equivalents include cash in bank accounts and short-term investments with maturities of three months or less when purchased.

**Regulatory balances**
The following regulatory treatment has resulted in accounting treatments which differ from IFRS for enterprises operating in an unregulated environment and regulated entities that did not adopt IFRS 14 Regulatory Deferral Accounts:

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous GAAP. IFRS 14 is restricted to first-time adopters of IFRS and will remain in force until it is either repealed or replaced by permanent guidance on rate regulated accounting from the IASB. The standard is effective for annual periods beginning on or after January 1, 2016. Early adoption is permitted. The utility has elected to early adopt IFRS 14 in its first statements under IFRS.

Regulatory balances provide useful information about the utility's financial position, financial performance and cash flows. Under rate regulated accounting the timing and recognition of certain revenues and expenses may differ from those otherwise expected under other IFRS's in order to reflect the impact of regulatory decisions. The regulatory balances that arise from the timing differences and qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and OEB prescribed accounting principles are segregated on the utility's balance sheet. The netting of regulatory debit and credit balances is not permitted. These regulatory balances represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers based on approvals by the OEB. The change in regulatory balances during the fiscal period is reflected on the statement of earnings and comprehensive income as net movements in regulated balances.

Regulatory deferral balances are recognized and measured initially and subsequently at cost. They are assessed for impairment on the same basis as other non-financial assets as follows:

The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgements, the balances will be recorded in the utility's statement of earning and other comprehensive income in the period the assessment is made.

### Accounts receivable and unbilled revenue

Accounts receivable are recorded at the invoiced amount and overdue amounts bear interest at the OEB prescribed rate. Unbilled revenue is recorded based on an estimated amount of electricity delivered but not billed. The carrying amount of accounts receivable and unbilled revenue is reduced through an allowance for doubtful accounts, if applicable, and the amount of the related impairment loss is recognized in the statement of earnings and comprehensive income.

Accounts receivable and unbilled revenue are assessed at year end to determine whether there is evidence of impairment. The utility considers historical trends on the timing of recoveries and the amount of loss incurred as well as current economic and credit conditions.

### Inventory

Inventories consist primarily of small consumable materials mainly related to the maintenance of the electricity infrastructure. The utility classifies all major construction related spare components of its electricity distribution infrastructure as property, plant and equipment. Inventories are measured at the lower of cost and net realizable value, with cost being determined on an average cost basis net of any provision for obsolescence.

### Property, plant and equipment

Property, plant and equipment are measured at cost less accumulated depreciation and any accumulated impairment losses, if applicable. For property, plant and equipment used in rate-regulated activities, the utility elected to use the exemption available for assets subject to rate regulation such that the previous Canadian GAAP carrying amount became deemed cost under IFRS at the date of transition - Note 31.

The cost of property, plant and equipment includes costs directly attributable to the acquisition of the asset. The cost of self constructed assets includes the cost of materials and direct labour, and any other costs directly attributable to bringing the asset to a working condition for its intended use.

The gain or loss on disposal of an item of property, plant and equipment is determined as the difference between the sale proceeds less the carrying amount of the asset and costs of removal and is recognized in the statement of earning and comprehensive income when that asset is disposed.

Depreciation begins when an asset becomes available for use. Depreciation of property, plant and equipment is recognized in the statement of earnings and comprehensive income on a straight-line basis over the estimated useful life of each part or component of an item of property, plant and equipment. Land is not depreciated. Construction in progress assets are not depreciated until the project is complete and in service. The estimated useful lives of the various assets used in the calculation of depreciation are summarized below:

| | Straight-line method estimated life (in years) |
|---|---|
| Buildings | 25 |
| Substation Equipment | 25 |
| Overhead Distribution System | 45 |
| Underground Distribution System | 45 |
| Services | 60 |
| Line Transformers | 40 |
| Meters | 15 - 25 |
| Trucks and Equipment | 4 - 8 |
| Computer Equipment | 10 |
| Office Equipment | 10 |

**Contributions in aid of construction**
Contributions in aid of construction are contributions received from electricity customers to construct or acquire property, plant and equipment. The contributions are deferred and amortized into revenue on a straight-line basis at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

**Goodwill**
Goodwill arising on the acquisition of subsidiaries or on amalgamation is measured at cost and is not amortized.

**Customer deposits**
Customers may be required to post security to obtain electricity or other services. Deposits to be refunded to customers within the next fiscal year are classified as a current liability. Interest rates paid on customer deposits are based on the Bank of Canada prime business rate less 2%.

**Employee future benefits**

a) Multi-employer pension plan

The utility provides a pension plan for all its full-time employees through the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards and school boards. The Fund is a contributory defined benefit pension plan which is financed by equal contributions from participating employers and employees and by the investment earnings in the Fund. Plan assets and pension obligations are not segregated into separate accounts for each member entity. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members. In this case the utility and its employees could face the prospect of higher contributions until the funded status of the Fund is restored. The utility is only able to recover additional contribution amounts in distribution rates if increased contribution rates are factored into the utility's rebasing rate applications before the OEB.

The OMERS plan is accounted for as a defined contribution plan and the contributions are recognized as an employee benefit expense in the statement of earning and comprehensive income in the period that service is rendered by the employee.

**b) Post-employment benefits - other than pension**
The Company provides some of its retired employees with extended health benefits and life insurance. The extended health benefits and life insurance plan is unfunded. The cost of these employee future benefit is recognized in the period in which the employees render the services.

The accrued benefit obligation and any current service costs are actuarially determined using the projected unit credit method and are based on assumptions that reflect management's best estimate of future salary levels, retirement ages of employees, health care costs and other actuarial factors. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses. Any actuarial gains(losses) will require a remeasurement of the net defined benefit liability or asset and will be recognized as other comprehensive income or loss in the year that it is known.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at December 31, 2013.

**Payments-In-Lieu of corporate taxes (PILS)**
The Company is a Municipal Electricity Utility for the purposes of the PILS regime contained in the Electricity Act, 1998 and is thereby exempt from tax under the Canadian Income Tax Act. It is required to make annual PILS payments to the Ontario Electricity Financial Corporation that are effectively equal to the tax that would be payable under the Canadian Income Tax Act .

The provision of PILS is comprised of current and deferred tax and is recognized directly in net income except to the extent that it relates to items recognized directly in equity or regulatory deferral accounts. Current PILS are recognized on the taxable income or loss for the current year plus any adjustment in respect of previous years. Current PILS are determined using tax rates and tax laws that have been enacted or substantively enacted by the year end date.

Deferred tax assets and liabilities are recognized where the carrying amount of an asset or liability differs from its tax base. The deferred tax asset or liability is measured at the amount expected to be recovered or paid using tax rates and tax laws that have been enacted or substantively enacted by year end and are expected to apply when the deferred tax asset/liability is settled.

Recognition of deferred tax assets for unused tax losses is restricted to those instances where it is probable that future taxable net income will be available against which the deferred tax asset can be utilized.

Management reassesses both recognized and unrecognized deferred tax assets at the end of each reporting period.

**Impairment of non-financial assets**
The carrying amount of the Utility's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the assets's recoverable amount is estimated. Goodwill and intangible assets with indefinite lives are tested annually for impairment and when circumstances indicate that the carrying value may be impaired. An impairment loss is recognized if the carrying amount of an asset exceeds its recoverable amounts.

**Future accounting pronouncements**
A number of new standards, amendments and interpretations have been published by the International Accounting Standards Board (IASB) but are not yet effective and have not been adopted early by the utility.

Information on new standards, amendments and interpretations that are expected to be relevant to the corporation's financial statements is provided below:

**IFRS 9 - financial instruments**
IFRS 9 amends the guidance on classification and measurement of financial instruments and replaces *IFRS 39 - Financial Instruments - Recognition and Measurement.* The new standard includes a new model for measuring impairment and carries forward the guidance in IFRS 39 related to the recognition and derecognition of financial instruments. The standard is effective January 1, 2018. The utility is in the process of assessing the impact of this new standard.

**IFRS 15 - revenue from contracts with customers**
IFRS 15 replaces all revenue recognition guidance and contains a single model that applies to contracts with customers and may impact the timing and amount of revenue recognized. The standard is effective January 1, 2018. The utility is in the process of assessing the impact of this new standard.

## 5. SEASONALITY

The corporation's operations are seasonal. The corporation's revenues tend to be higher in the first and third quarter of the year as a result of higher energy consumption for winter heating in the first quarter and air conditioning and cooling in the third quarter. The volume of electricity consumed by customers during any period is governed by events largely outside of the corporation's control (principally, sustained periods of hot or cold weather which increases the consumption of electricity, and sustained periods of moderate weather which decreases the consumption of electricity).

## 6. ACCOUNTS RECEIVABLE

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Trade receivables | **$ 732,148** | $ 506,540 | $ 857,692 |
| Other miscellaneous receivables | **90,640** | (89,458) | (370,694) |
| | **822,788** | 417,082 | 486,998 |
| Less: allowance for doubtful accounts (Note 19) | **(10,902)** | (10,000) | (1,060) |
| | **$ 811,886** | $ 407,082 | $ 485,938 |

## 7. REGULATORY BALANCES

Debit balances consist of the following:

| | January 1, 2015 | Balances arising in the period | Recovery | Carrying Charges | December 31, 2015 |
|---|---|---|---|---|---|
| Settlement variances | $ 259,907 | $ (128,928) | $ - | $ 2,701 | **$ 133,680** |
| Stranded meters | 116,953 | (44,016) | - | 1,143 | **74,080** |
| Extraordinary event | 282,712 | 2,682 | (102,098) | - | **183,296** |
| RARA - Sept 2012 | 3,618 | - | (367) | - | **3,251** |
| RARA - May 2014 | 161,011 | - | (181,800) | 271 | **(20,518)** |
| | $ 824,201 | $ (170,262) | $ (284,265) | $ 4,115 | **$ 373,789** |

| | January 1, 2014 | Balances arising in the period | Recovery | Carrying Charges | December 31, 2014 |
|---|---|---|---|---|---|
| Settlement variances | $ 753,260 | $ 188,917 | $ (529,483) | $ 11,842 | $ 424,536 |
| Stranded meters | 158,479 | - | (43,561) | 2,035 | 116,953 |
| Extraordinary event | 379,827 | - | (101,881) | 4,766 | 282,712 |
| Other | 1,911 | (997) | - | 47 | 961 |
| | $1,293,477 | $ 187,920 | $ (674,925) | $ 18,690 | $ 825,162 |

Credit balances consist of the following:

| | January 1, 2015 | Balances arising in the period | Recovery | Carrying Charges | December 31, 2015 |
|---|---|---|---|---|---|
| IFRS Transition | $ 72,507 | $ (36,253) | $ - | $ - | **$ 36,254** |
| Other | (961) | 1,152 | - | (6) | **185** |
| | $ 71,546 | $ (35,101) | $ - | $ (6) | **$ 36,439** |

| | January 1, 2014 | Balances arising in the period | Recovery | Carrying Charges | December 31, 2014 |
|---|---|---|---|---|---|
| IFRS transition | $ 108,761 | $ (36,254) | $ - | $ - | $ 72,507 |

The following provides a summary of approved recovery periods for the variance noted above:

| | |
|---|---|
| Stranded meters | 4 years beginning September 2013 |
| Extraordinary event | 4 years beginning September 2013 |
| RARA - May 2014 | one year beginning May 2014 |
| IFRS transition variance | 4 years beginning September 2013 |

The settlement variances and RARA Sept 2012 will be requested for recovery in either the next IRM or Cost of Service application process.

The "Balances arising in the period" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery" column consists of amount collected through rate riders .

**Settlement variances**
The variance represents the difference between the amount charged by the utility to its customers based on regulated rates and the corresponding costs incurred by the company for electricity and non-competitive electricity charges incurred by the utility. The utility has deferred the difference between the costs incurred and the related recoveries in accordance with the criteria included in the accounting principles prescribed by the OEB. The variance primarily consist of service charges, non-competitive electricity charges and the global adjustment. The variance will be recovered in future billing periods and through future hydro rates as approved by the Ontario Energy Board.

Interest is added monthly, calculated and recorded using simple interest at a prescribed rate on the carrying value to compensate the utility for the timing difference. The offsetting credit/debit is recorded as interest income/expense.

### Stranded meters

This variance account represents the net book value of mechanical meters that were replaced by smart meters less amounts recovered via an approved rate rider that is effective September 1, 2013 to August 31, 2017.

### Extraordinary event costs

In August 2011, the Town of Goderich was hit by an F3 tornado. This storm resulted in significant damage to the utility's distribution system. Under regulatory procedures set by the OEB, costs related to an extraordinary event may be considered for recovery if the event meets several criteria.

The utility applied for recovery of the expenditures through the cost of service rate rate process and a rate rider was approved that is effective from September 1, 2013 to August 31, 2017.

The variance balance consists of the costs incurred less recoveries via rider plus carrying charges accrued annually on the net uncollected principle balance.

### IFRS transition

This regulatory balance relates to the difference arising from accounting policy changes for property, plant and equipment and intangible assets due to transition from Canadian GAAP to IFRS and is primarily due to useful life changes as part of componentization. This balance is reduced annually by $36,254 for a four year period beginning in 2013 with the amount charged against depreciation expense.

### Regulatory Asset/Liability Recovery Account (RARA)

The RARA consists of balances of regulatory assets and regulatory liabilities that have been approved for disposition through Ontario Energy Board approved rate riders. The RARA is subject to carrying charges using rates approved by the Ontario Energy Board and calculated monthly using the simple interest method. Revenues collected via these specific distribution rate riders are allocated to the RARA as they are intended to offset or recover the approved amounts.

Any over/under recovery of these approved amounts will be factored into future rate approvals.

## 8. PROPERTY, PLANT AND EQUIPMENT

(a) Cost or deemed cost

| | Balance at January 1, 2014 | Additions | Transfers | Disposals | Balance at December 31, 2014 |
|---|---|---|---|---|---|
| Land | $ 21,747 | $ - | $ - | $ - | **$ 21,747** |
| Buildings | 43,065 | - | - | - | **43,065** |
| Substation equipment | 73,138 | - | - | - | **73,138** |
| Overhead distribution | 2,881,767 | 45,616 | 6,557 | - | **2,933,940** |
| Underground distribution | 1,221,874 | 279,823 | 263,437 | - | **1,765,134** |
| Services | 327,075 | 25,536 | 685 | - | **353,296** |
| Line transformers | 1,206,521 | 125,398 | 63,848 | - | **1,395,767** |
| Meters | 641,642 | 15,971 | - | - | **657,613** |
| Trucks and equipment | 279,183 | 292,735 | 98,847 | (5,472) | **665,293** |
| Computer equipment | 24,428 | 3,979 | - | - | **28,407** |
| Office equipment | - | 6,550 | - | - | **6,550** |
| Construction in progress | 775,179 | 466,792 | (433,374) | - | **808,597** |
| Major parts and supplies | 620,200 | - | (38,980) | - | **581,220** |
| | $ 8,115,819 | $ 1,262,400 | $ (38,980) | $ (5,472) | **$ 9,333,767** |

| | Balance at January 1, 2015 | Additions | Transfers | Disposals | Balance at December 31, 2015 |
|---|---|---|---|---|---|
| Land | $ 21,747 | $ - | $ - | $ - | **$ 21,747** |
| Buildings | 43,065 | - | - | - | **43,065** |
| Substation equipment | 73,138 | - | - | - | **73,138** |
| Overhead distribution | 2,933,940 | 40,373 | 318,948 | (2,492) | **3,290,769** |
| Underground distribution | 1,765,134 | 49,510 | 200,070 | - | **2,014,714** |
| Services | 353,296 | 41,949 | - | - | **395,245** |
| Line transformers | 1,395,767 | 56,380 | 279,225 | (15,310) | **1,716,062** |
| Meters | 657,613 | 15,368 | - | - | **672,981** |
| Trucks and equipment | 665,293 | 46,208 | - | - | **711,501** |
| Leasehold improvement | - | 8,560 | - | - | **8,560** |
| Computer equipment | 28,407 | - | - | - | **28,407** |
| Office equipment | 6,550 | 558 | - | - | **7,108** |
| Construction in progress | 808,597 | 434,746 | (798,243) | - | **445,100** |
| Major parts and supplies | 581,220 | - | (100,374) | - | **480,846** |
| | $ 9,333,767 | $ 693,652 | $ (100,374) | $ (17,802) | **$ 9,909,243** |

(b) Accumulated depreciation

| | Balance at January 1, 2014 | Amortization | Impairment Loss | Reversals | Balance at December 31, 2014 |
|---|---|---|---|---|---|
| Buildings | $ - | $ 3,240 | $ - | $ - | **$ 3,240** |
| Substation equipment | - | 6,090 | - | - | **6,090** |
| Overhead distribution | - | 76,601 | - | - | **76,601** |
| Underground distribution | - | 48,113 | - | - | **48,113** |
| Services | - | 7,818 | - | - | **7,818** |
| Line transformers | - | 35,411 | - | - | **35,411** |
| Meters | - | 47,900 | - | - | **47,900** |
| Trucks and equipment | - | 77,682 | - | - | **77,682** |
| Computer equipment | - | 4,587 | - | - | **4,587** |
| Office equipment | - | 327 | - | - | **327** |
| | $ - | $ 307,769 | $ - | $ - | **$ 307,769** |

| | Balance at January 1, 2015 | Amortization | Impairment Loss | Reversals | Balance at December 31, 2015 |
|---|---|---|---|---|---|
| Buildings | $ 3,240 | $ 3,237 | $ - | $ - | **$ 6,477** |
| Substation equipment | 6,090 | 6,090 | - | - | **12,180** |
| Overhead distribution | 76,601 | 83,380 | - | (133) | **159,848** |
| Underground distribution | 48,113 | 50,141 | - | - | **98,254** |
| Services | 7,818 | 7,145 | - | - | **14,963** |
| Line transformers | 35,411 | 57,360 | - | (1,623) | **91,148** |
| Meters | 47,900 | 50,376 | - | - | **98,276** |
| Trucks and equipment | 77,682 | 101,812 | - | - | **179,494** |
| Leasehold improvement | - | 214 | - | - | **214** |
| Computer equipment | 4,587 | 6,577 | - | - | **11,164** |
| Office equipment | 327 | 684 | - | - | **1,011** |
| | $ 307,769 | $ 367,016 | $ - | $ (1,756) | **$ 673,029** |

(c) Carrying amounts

| | 2015 | 2014 |
|---|---|---|
| Land | **$ 21,747** | $ 21,747 |
| Buildings | **36,588** | 39,825 |
| Substation equipment | **60,958** | 67,048 |
| Overhead distribution | **3,130,921** | 2,857,339 |
| Underground distribution | **1,916,460** | 1,717,021 |
| Services | **380,282** | 345,478 |
| Line transformers | **1,624,914** | 1,360,356 |
| Meters | **574,705** | 609,713 |
| Trucks and equipment | **532,007** | 587,611 |
| Leasehold improvements | **8,346** | - |
| Computer equipment | **17,243** | 23,820 |
| Office equipment | **6,097** | 6,223 |
| Construction in progress | **445,100** | 808,597 |
| Major parts and supplies | **480,846** | 581,220 |
| | **$ 9,236,214** | $ 9,025,998 |

## 9. INTANGIBLE ASSETS

a) The utility's intangible assets consist of computer software.

| | |
|---|---|
| **Cost** | |
| January 1, 2014 | $ 57,479 |
| Additions | - |
| December 31, 2014 | 57,479 |
| Additions | 36,555 |
| December 31, 2015 | $ 94,034 |
| **Accumulated Amortization** | |
| January 1, 2014 | $ - |
| Amortization | 10,310 |
| December 31, 2014 | 10,310 |
| Amortization | 13,690 |
| December 31, 2015 | $ 24,000 |
| **Carrying amounts** | |
| January 1, 2014 | $ 57,479 |
| December 31, 2014 | $ 47,169 |
| December 31, 2015 | $ 70,034 |

Computer software is recorded at cost and amortized on a straight-line basis over 10 years.

## 10. ACCOUNTS PAYABLE AND ACCRUALS

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Trade payables | **$ 1,490,606** | $ 1,513,035 | $ 1,795,078 |
| Accrued liabilities | **85,637** | 54,048 | 88,679 |
| Government remittances | **12,566** | (13,679) | (56,608) |
| Due to (from) Town of Goderich | **-** | (2,154) | - |
| | **$ 1,588,809** | $ 1,551,250 | $ 1,827,149 |

## 11. CONTRIBUTIONS IN AID OF CONSTRUCTION

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Deferred contributions, beginning of year | **$ 271,231** | $ - | $ - |
| Contributions in aid of construction received | **46,777** | 274,378 | - |
| Contributions in aid of construction recognized as revenue | **(6,840)** | (3,147) | - |
| | **$ 311,168** | $ 271,231 | $ - |

## 12. TOWN OF GODERICH DEMAND LOAN

The demand loan bears interest at prime plus 1% and secured by a general security interest over all present and future assets.

## 13. BANK LOANS

| | 2015 | 2014 |
|---|---|---|
| Bank loan bearing interest at prime plus 0.4% annually; due February 2017; repayable with monthly payments of $7,072 plus interest; secured by a general security agreement over all property | **$ 1,541,800** | $ 1,625,400 |
| Bank loan bearing interest at prime plus 0.4% annually; due February 2017; repayable with monthly payments of $1,571 plus interest; secured by a general security agreement over all property | **377,000** | - |
| Bank loan bearing interest at prime plus 0.4% annually; due February 2017; repayable with monthly payments of $4,050 plus interest; secured by a general security agreement over all property | **271,150** | 319,750 |
| | **2,189,950** | 1,945,150 |
| Current portion | **152,322** | 132,312 |
| | **$ 2,037,628** | $ 1,812,838 |

The approximate principal payments due are as follows:

| | |
|---|---|
| 2016 | $ 152,322 |
| 2017 | 2,037,628 |
| | $ 2,189,950 |

## 14. NOTE PAYABLE

The note is payable to the shareholder of the company, is due upon demand and bears interest at 7.25% per annum. The note is secured by a general security agreement over all of the Company's assets. The note has been classified as long-term because it is not the intent of the shareholder to demand repayment within the next year. Interest expense for the year is **$70,048** (2014 - $70,648).

## 15. EMPLOYEE FUTURE BENEFITS

### Pension

The assets and pension obligations of this multi-employer plan are not segregated into separate accounts for each member entity. As at December 31, 2015, the plan was 91.5% (2014 - 90.8%) funded. The plan's most recent actuarial valuation was performed at December 31, 2015. The Primary Plan is reporting actuarial liabilities of $81.9 billion (2014 - $77 billion) and actuarial net assets available for benefits of $74.9 billion (2014 - $69.9 billion) creating an actuarial deficit of $7 billion (2014 - $7.1 billion). Total contributions for all participating employers and employees into the Primary Plan for 2015 was approximately $3.8 billion (2014 - $3.7 billion) The total contributions of the utility and its employees for 2015 was **$113,458** (2014 - $113,510). The utility expects to contribute approximately $113,000 in 2016.

### Post employment medical and life insurance plan

The utility provides post-retirement life insurance benefits to all retirees and extended health, dental and vision benefits until age of 65 for employees meeting specific age and service requirements. This benefit plan is unfunded. The utility has recorded its share of the defined benefit costs and the related liability in these financial statements based on calculations made by an actuary. The most recent actuarial valuation was performed as at January 1, 2013 and provides the basis for the reported accrued benefit liability and expenses for 2014 and 2015.

The plan is exposed to several risks including interest rate risk, longevity risk and health care benefit cost risk. Changes in interest rates used to discount the liability, changes to assumptions related to the life span of its employees and changes in the costs of providing the health care benefits will all impact the assumptions used in the actuarial valuation of the accrued benefit liability.

| **Defined benefit obligation** | **2015** | 2014 |
|---|---|---|
| Defined benefit obligation, beginning of year | **$ 314,273** | $ 329,069 |
| Amounts recognized in net earnings | | |
| Current service cost | **13,916** | 13,916 |
| Interest cost on obligation | **5,010** | 5,010 |
| Benefit payments | **(29,742)** | (33,722) |
| Defined benefit obligation, end of year | **$ 303,457** | $ 314,273 |

**Significant assumptions**

| | **2015** | 2014 |
|---|---|---|
| Discount rate used in the calculation of the defined benefit obligation | **3.65 %** | 3.65 % |
| Rate of increase in dental costs | **4.60 %** | 4.60 % |
| Rate of increase in health benefits costs | **6.70 %** | 6.70 % |
| Rate of compensation increase | **-** | - |
| Age of retirement | **60** | 60 |

**Sensitivity analysis - (in thousands)**

| | As reported | 1% increase | 1% decrease |
|---|---|---|---|
| Health and dental cost | 386 | 399 | 375 |

Retirement age change to 58 from 60 would increase the obligation from $386 to $414

## 16. CREDIT FACILITIES

The company has a revolving demand facility with an authorized limit of $1,000,000 available under the credit facility with a Canadian chartered bank. The line of credit bears interest at the bank's prime rate, calculated and payable monthly. The facility is secured by a general security agreement covering all company assets excluding real property. A priority agreement has also been obtained in favour of the bank over the Town of Goderich.

The company has arranged a second credit facility. This facility is a non-revolving demand facility with an authorized limit of $525,000. It bears interest at the bank's prime rate, calculated and payable monthly.

**Letter of credit**

The company has provided prudentials, in the form of an irrevocable letter of credit, in the amount of **$582,133** (2014 - $582,133) in favour of the Independent Electricity System Operator. The prudentials serves as security for power purchased from the Independent Electricity Market Operator.

## 17. OTHER REVENUE (EXPENSES)

| | 2015 | 2014 |
|---|---|---|
| Conservation funding | $ **299,712** | $ 163,014 |
| Miscellaneous service revenue | **45,033** | 70,474 |
| Water and sewer collection fees | **42,580** | 42,418 |
| Specific service charges | **22,655** | 22,365 |
| Rental from electric property | **16,599** | 15,340 |
| SSS admin | **10,942** | 10,964 |
| Bank interest | **10,659** | 6,703 |
| Late payment charges | **8,884** | 10,538 |
| Service transaction requests | **4,420** | 3,580 |
| Retail service charges | **3,137** | 2,754 |
| Non-utility operations - water heaters | - | 3,742 |
| Non-utility operations - water heater expenses | - | (153) |
| Gain (loss) on disposal of property, plant and equipment | **(16,046)** | 34,107 |
| Conservation expenses | **(299,712)** | (163,014) |
| | $ **148,863** | $ 222,832 |

## 18. AMORTIZATION EXPENSE

| | 2015 | 2014 |
|---|---|---|
| Property, plant and equipment | $ **279,759** | $ 237,980 |
| Intangibles | **13,690** | 10,310 |
| Transition variance | **(36,253)** | (36,254) |
| | **257,196** | 212,036 |
| Vehicles - allocated to other accounts | **87,256** | 69,791 |
| | $ **344,452** | $ 281,827 |

## 19. BAD DEBTS EXPENSE

Bad debt expense is included in Billing and Collection expense on the Statement of Earnings and Comprehensive Income and includes the following activity for the year:

| | 2015 | 2014 |
|---|---|---|
| Write-offs during the year | $ 11,113 | $ - |
| Recoveries during the year | (1,015) | - |
| Opening allowance | (10,000) | (1,060) |
| Closing allowance | 10,902 | 10,000 |
| | $ 11,000 | $ 8,940 |

## 20. SALARIES AND BENEFITS EXPENDITURES

The utility charges salaries and benefits expense to each function based on time spent. The costs were allocated as follows:

| | 2015 | 2014 |
|---|---|---|
| Operations and maintenance | $ 323,128 | $ 353,908 |
| Billing and collecting | 173,632 | 167,254 |
| Capital asset construction and work in progress | 168,950 | 149,427 |
| Administration and general | 167,904 | 172,778 |
| Streetlight maintenance services | 13,545 | 38,515 |
| | $ 847,159 | $ 881,882 |

## 21. FINANCING INCOME AND CHARGES

| | 2015 | 2014 |
|---|---|---|
| **Finance income** | | |
| Carrying charges on regulatory deferrals | $ 6,803 | $ 18,692 |
| **Finance charges** | | |
| Demand loan | $ 75,488 | $ 80,000 |
| Note payable | 70,648 | 70,648 |
| Bank loan | 60,497 | 40,697 |
| Other | 11,909 | 13,642 |
| | $ 218,542 | $ 204,987 |

## 22. PAYMENTS IN LIEU OF CORPORATE TAXES

The provision for payment in lieu of income taxes recognized in income is as follows:

| | 2015 | 2014 |
|---|---|---|
| **Current tax** | | |
| Based on current taxable income | $ 25,500 | $ 27,952 |
| **Deferred tax** | | |
| Origination and reversal of timing differences | 22,060 | 71,550 |
| | $ 47,560 | $ 99,502 |

The provision for PILS differs from the amount that would have been recorded using the combined Canadian federal and provincial statutory income tax rate. Statutory Canadian federal and provincial tax rates for the current year comprise 15% (2014 - 15%) for federal corporate tax and 11.5% (2014 - 11.5%) for corporate tax in Ontario. For corporations with assets of less than $15 million the statutory rate is reduced on the first $500,000 of taxable income to 15.5% The reconciliation between the statutory and effective rates is provided as follows:

| | **2015** | 2014 |
|---|---|---|
| Income before provision for PILS | $ **273,337** | $ 529,083 |
| Statutory Canadian federal and provincial income tax rate | **15.5%** | 15.5% |
| Expected tax provision on income at statutory rates | $ **42,367** | $ 82,008 |
| Increase (decrease) in income taxes resulting from: | | |
| Capital cost allowance in excess of amortization | **(40,808)** | (46,659) |
| Other | **23,941** | (7,397) |
| Provision for PILS | $ **25,500** | $ 27,952 |

**Deferred payments in lieu of income taxes**
Significant components of the Utility's deferred payments in lieu balances are as follows:

| **Deferred PILs liability** | **2015** | 2014 |
|---|---|---|
| Property, plant and equipment and intangibles | $ **50,373** | $ (14,229) |
| Employee benefits | **(47,036)** | (48,712) |
| Other | **17,102** | 61,320 |
| | $ **20,439** | $ (1,621) |

## 23. SHARE CAPITAL

| | **2015** | 2014 |
|---|---|---|
| Authorized share capital | | |
| Unlimited number of common shares with no par value | | |
| Issued share capital | | |
| 1 common share; fully paid | $ **3,410,092** | $ 3,410,092 |

There has been no movement in share capital during 2015 or 2014.

## 24. DIVIDENDS

Dividends of **$100,000** (2014 - $125,000) were declared. The amount of dividends declared each year is at the discretion of the Board of Directors.

## 25. SUPPLEMENTAL CASH FLOW INFORMATION

| | 2015 | 2014 |
|---|---|---|
| Change in non-cash operating working capital | | |
| Increase in receivables | $ **(404,804)** | $ 78,856 |
| Decrease (increase) in unbilled revenue | **(85,119)** | 67,652 |
| Decrease in dividends payable | **(25,000)** | 125,000 |
| Increase(decrease) in deferred revenue | **(4,932)** | (101,305) |
| Increase (decrease) in payables and accruals | **37,558** | (275,899) |
| Increase in future income tax asset/liability | **22,060** | 71,550 |
| Decrease in payments-in-lieu of corporate taxes receivable/payable | **18,905** | (45,375) |
| | $ **(441,332)** | $ (79,521) |

## 26. RELATED PARTY TRANSACTIONS

West Coast Huron Energy is wholly owned by the Corporation of the Town of Goderich. Since the parent of the utility is a local government, the utility is exempt from some the general disclosure requirements of IAS 24 related to its transactions with its parent company.

The following summarizes the utility's related party transactions for the year. The transactions occurred in the normal course of operations and are measured at the exchange amount which is the amount of consideration established and agreed to by the related parties. The exchange value approximates the arm's length value of the sales or services provided.

| | 2015 | 2014 |
|---|---|---|
| **Revenues** | | |
| Streetlight hydro | $ **250,629** | $ 224,114 |
| Water and sewer collection fees | **42,580** | 42,418 |
| Streetlight maintenance | **28,407** | 34,697 |
| **Expenses** | | |
| Interest on debt | **146,136** | 150,648 |
| Rent | **104,352** | 103,319 |
| Dividends | **100,000** | 125,000 |
| Administration and services fees | **79,000** | 79,000 |
| Health and Safety services | **12,000** | - |
| Environmental services | **-** | 31,330 |

Streetlight revenues were charged to the shareholder based on rates approved by the OEB consistent with rates determined for all other customers.

During the year, the directors of the utility received compensation in the amount of **$45,597** (2014 - $46,888).

At year end, the utility owed the Corporation of the Town of Goderich the following:

| | | **2015** | | 2014 |
|---|---|---|---|---|
| Water and sewer revenue, net of fees | $ | **292,614** | $ | 284,867 |
| Dividends | | **100,000** | | 125,000 |
| Health and safety services fees | | **12,000** | | - |
| Environmental services fees | | - | | 9,201 |

## 27. COMMITMENT

The Company has the following obligations under operating leases for operations premises and office space:

| | |
|---|---|
| 2016 | $ 106,100 |
| 2017 | $ 106,100 |
| 2018 | $ 106,100 |
| 2019 | $ 106,100 |
| 2020 | $ 106,100 |

The operating leases have a 20 year term. The lease for the operations premise expires in 2033 and the office space lease term expires in 2030.

## 28. CAPITAL DISCLOSURES

The Company's capital structure consists of its share capital, retained earnings and the accumulated balance in other comprehensive income as well as the long-term note payable to its shareholder. The Company's main objectives when managing its capital are as follows:

- deliver a reasonable return on the investments of its shareholder;
- to ensure adequate liquidity to maintain and improve its distributions system and meet it financial obligations;
- to align its capital structure for regulated activities with the debt to equity structure deemed by the Ontario Energy Board

The Company's note payable agreement does not contain any covenants.

## 29. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

### Fair value of financial instruments

The Company's financial instruments include cash, bank indebtedness, receivables, unbilled revenue, accounts payables, accrued liabilities, dividends payable and customer deposits. The carrying value of these instruments approximates their fair value due to their immediate or short-term maturity.

Financial instruments also include the note payable with terms as disclosed in Note . The fair value has not been determined or disclosed as the cash flows related to this liability are uncertain.

The estimated fair value of long-term debt is **$2,037,628** (2014 - $1,812,838). The fair value is calculated based on the present value of the future principal and interest cash flows, discounted at the current rate of interest at the reporting date.

Fair value estimates are subjective by nature and contain uncertainties and matters of significant judgement. The estimates are based on market prices and information available at the time and may not necessarily be indicative of actual amounts the Utility will receive or incur in actual market transactions.

**Determination of fair value**

Financial instruments which are disclosed at fair value are to be classified using a three- level hierarchy. Each level reflects the inputs used to measure the fair values disclosed for financial liability as follows:

Level 1: inputs are unadjusted quoted prices of identical instruments in active markets;

Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability either directly or indirectly; and,

Level 3: inputs for the liabilities that are not based on observable market data (unobservable inputs).

The Utility's fair value hierarchy is classified as Level 2 for long-term debt. The classification for disclosure purposes has been determined using the discounted cash flow model based on the contractual terms of the debt instrument discounted using an appropriate market rate of interest.

**Financial risk management**

As part of its operations, the company carries out transactions that expose it to financial risks such as credit, liquidity and market risks. The following is a discussion of risks and mitigation strategies identified by management. However, the risks described below are not exhaustive of all the risks nor will the mitigation strategies eliminate the utility's exposure to all risks listed.

**Credit risk**

The risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation. The maximum credit exposure is limited to the carrying amount of cash and receivables and unbilled revenue presented on the balance sheet.

The Company limits its credit risk related to cash by placing its cash with a high quality financial institution.

The Company is exposed to credit risk related to accounts receivable arising from its electricity and service revenue. Exposure to credit risk from its accounts receivable is limited due to the corporation's diverse customer base. As of December 31, 2015 the utility has approximately 3,840 customers. In addition, the Company holds customer and construction deposits which are recognized as liabilities on the balance sheet. The Company does not have material customer accounts receivable balances greater than 90 days outstanding. As a result, the Company believes that its accounts receivable represent a low credit risk.

The utility has one customer that generated revenue of **$1,294,689** (2014 - $1,178,968) which represents more than 10% of total revenue for the years ended December 31, 2015 and December 31, 2014.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts. The balance of the allowance for impairment as at December 31, 2015 is **$10,902** (2014 - $10,000). An impairment loss of **$11,000** (2014 - $17,178) has been recognized in net earnings.

Accounts receivable aging analysis is as follows

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Outstanding for not more than 30 days | $ **701,194** | $ 493,111 | $ 841,858 |
| Outstanding for more than 30 days and not more than 90 days | **11,441** | 2,989 | 6,977 |
| Outstanding for more than 90 days | **19,513** | 10,440 | 8,857 |
| | **732,148** | 506,540 | 857,692 |
| Unbilled revenue | **1,161,982** | 1,076,863 | 1,144,515 |
| | $ **1,894,130** | $ 1,583,403 | $ 2,002,207 |

Unbilled revenue represents amounts for which the Utility has a contractual right to receive cash through future billings but are unbilled at year end. Unbilled revenue is considered to be current and no allowance for doubtful accounts has been provided as at December 31, 2015, December 31, 2014 and January 1, 2014.

**Market risk**
Market risk refers to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Utility does not have any direct exposure to commodity or foreign exchange risk.

The Utility manages its exposure to interest rate risk by issuing long-term fixed rate debt in the form of bank loans and promissory note. It also ensures that all payment obligations can be met through proper capital planning.

The Utility has a revolving demand credit facility which it can utilize for working capital and/or capital expenditure purposes. Such short term borrowings may expose the Utility to fluctuations in short-term interest rates. The Town of Goderich demand note payable is also at a variable rate further exposing the entity to short-term rate fluctuations.

A sensitivity analysis was conducted to determine the impact of a 1% increase in the prime lending rate. This interest rate variation with all other variable held constant would result in an estimated increase of $41,900 in annual finance cost.

**Liquidity risk**
Liquidity risk is the risk that the company will encounter difficulty in meeting obligations associated with financial liabilities as they come due. The Company monitors and manages its liquidity risk to ensure, as far as possible, access to sufficient funds to meet operational and investing requirements. It monitors its cash balances to ensure sufficient levels of liquidity are on hand to meet its financial commitments as they come due while minimizing interest exposure.

Liquidity risk associated with financial commitments are as follows:

| | 0 - 3 mo | 3 mo - 1yr | 1 - 5yr | Thereafter | Total |
|---|---|---|---|---|---|
| Accounts payable | $ 1,516,680 | $ 72,128 | $ - | $ - | $ 1,588,808 |
| Dividends payable | 100,000 | - | - | - | 100,000 |
| Customer deposits | - | 50,000 | 94,096 | - | 144,096 |
| Long-term debt | 38,079 | 114,243 | 2,037,628 | - | 2,189,950 |
| | $ 1,654,759 | $ 236,371 | $ 2,131,724 | $ - | $ 4,022,854 |

## 30. INSURANCE

The Company holds insurance with major insurers at appropriate types and levels as determined by management. It is a member of the Municipal Electricity Association Reciprocal Insurance Exchange (MEARIE) for its liability coverage. This reciprocal insurance exchange is formed to exchange reciprocal contracts of indemnity or inter-insurance among the members of the group. All members of the pool are subject to assessment for losses experienced by the pool, for the years in which they were members. As at December 31, 2015, the Utility has not been made aware of any assessment for losses. Insurance premiums are charged to each member as a fee per thousands of dollars of service revenue with an adjustment to reflect the member's claims experience. The coverage provided by this insurance is to a level of $20,000,000 per occurrence. The utility does not currently hold insurance coverage for its distribution assets.

## 31. EXPLANATION OF TRANSITION TO IFRS

As stated in Note 2, these are the Corporation's first financial statements prepared in accordance with IFRS. IFRS 1 (First-time Adoption of International Financial Reporting Standards) has been applied in preparing these financial statements.

The accounting policies set out in Note 4 have been applied in preparing the financial statements for the year ended December 31, 2015, the comparative information presented in these financial statements for the year ended December 31, 2014 and in the preparation of the opening IFRS balance sheets at January 1, 2014 ( the Utility's date of transition).

In preparing its opening IFRS balance sheet, the Corporation has adjusted amounts reported previously in financial statements prepared in accordance with Canadian GAAP. An explanation of how the transition from Canadian GAAP to IFRS has affected the Utility's financial position, financial performance and cash flows has been set out in the following tables and the notes that accompany the tables.

### IFRS exemption

IFRS 1 set out the procedures that the Corporation must follow when it adopts IFRS for the first time as the basis for preparing its financial statements. The Corporation is required to establish its IFRS accounting policies as at December 31, 2015 and, in general, apply these retrospectively to determine the IFRS opening balance sheet at its date of transition, January 1, 2014. IFRS 1 provides a number of mandatory and optional exemptions to this general principle.

### Mandatory exception

IFRS 1 states that estimates made in accordance with IFRS at the transition date should be consistent with estimates made under previous GAAP. Accordingly, estimates previously made under Canadian GAAP were not revised at the date of transition except where necessary to reflect changes in accounting policies.

**Optional exemptions**

i) Deemed cost for operations subject to rate regulation:

IFRS 1 offers an optional exemption for a first-time adopter with rate-regulated activities to use the carrying amount of fixed assets or intangible assets as deemed cost on transition date when the carrying amount includes costs that would not qualify for capitalization in accordance with IFRS. The Corporation elected this exemption and used the carrying amount of the fixed assets and intangibles under Canadian GAAP as deemed cost on transition date. The impact of this change is a decrease in both cost and accumulated depreciation of property, plant and equipment by $2,744,786 and intangible assets by $73,226 as at January 1, 2014. The Utility tested for asset impairment under this exemption and no impairment was recorded.

ii) Transfers of assets from customers (Capital contributions)

The Utility elected to apply the IFRS 1 election to apply IFRIC 18 prospectively from the date of transition to transfers of assets from customers received on or after the transition date.

iii) Borrowing costs

The Utility has elected to apply the transitional provisions of IAS 23 which permits prospective capitalization of borrowing costs to qualifying assets from the date of transition.

The reconciliations of the January 1, 2014 and December 31, 2014 balance sheets from Canadian GAAP to IFRS is as follows:

| **Balance Sheet As at January 1, 2014** | **Notes** | **Canadian GAAP** | **Transitional Adjustments** | **IFRS** |
|---|---|---|---|---|
| **ASSETS** | | | | |
| **Current** | | | | |
| Receivables | | $ 485,938 | $ - | $ 485,938 |
| Unbilled revenue | | 1,144,515 | - | 1,144,515 |
| Prepaids | | 10,510 | - | 10,510 |
| Total current assets | | 1,640,963 | - | 1,640,963 |
| Property, plant and equipment | | 8,115,819 | - | 8,115,819 |
| Intangibles | | 57,479 | - | 57,479 |
| Goodwill | | 68,119 | - | 68,119 |
| Regulatory assets | (a) | 1,184,716 | (1,184,716) | - |
| Deferred tax asset | | 56,800 | 16,371 | 73,171 |
| Total assets | | 11,123,896 | (1,168,345) | 9,955,551 |
| Regulatory balances | (a) | - | 1,293,477 | 1,293,477 |
| **Total assets and regulatory balances** | | $ 11,123,896 | $ 125,132 | $ 11,249,028 |
| **LIABILITIES** | | | | |
| **Current** | | | | |
| Bank indebtedness | | $ 386,756 | $ - | $ 386,756 |
| Payables and accruals | | 1,827,149 | - | 1,827,149 |
| Income taxes payable | | 17,731 | - | 17,731 |
| Deferred revenue | | 106,237 | - | 106,237 |
| Town of Goderich demand loan | | 2,000,000 | - | 2,000,000 |
| Current portion of customer deposits | | 50,000 | - | 50,000 |
| Total current liabilities | | 4,387,873 | - | 4,387,873 |
| Note payable | | 974,454 | - | 974,454 |
| Post-employment benefits | (b) | 223,448 | 105,621 | 329,069 |
| Customer deposits | | 195,727 | - | 195,727 |
| Total liabilities | | 5,781,502 | 105,621 | 5,887,123 |
| **EQUITY** | | | | |
| Capital stock | | 3,410,092 | - | 3,410,092 |
| Retained earnings | | 1,932,302 | - | 1,932,302 |
| Other comprehensive income | (b) | - | (89,250) | (89,250) |
| Total liabilities and equity | | 11,123,896 | 16,371 | 11,140,267 |
| Regulatory balances | (a) | - | 108,761 | 108,761 |
| **Total liabilities, equity and regulatory balances** | | $ 11,123,896 | $ 125,132 | $ 11,249,028 |

## West Coast Huron Energy Inc.
## Notes to the Financial Statements
**December 31, 2015**

| Balance Sheet As at December 31, 2014 | Notes | Canadian GAAP | Transitional Adjustments | IFRS |
|---|---|---|---|---|
| **ASSETS** | | | | |
| **Current** | | | | |
| Cash | | $ 1,474,960 | $ - | $ 1,474,960 |
| Receivables | | 407,082 | - | 407,082 |
| Unbilled revenue | | 1,076,863 | - | 1,076,863 |
| Income taxes receivable | | 27,644 | - | 27,644 |
| Prepaids | | 10,510 | - | 10,510 |
| Total current assets | | 2,997,059 | - | 2,997,059 |
| Property, plant and equipment | (c) | 8,754,767 | 271,231 | 9,025,998 |
| Intangibles | | 47,169 | - | 47,169 |
| Goodwill | | 68,119 | - | 68,119 |
| Regulatory assets | (a) | 752,655 | (752,655) | - |
| Deferred tax asset | (d) | - | 1,621 | 1,621 |
| Total assets | | 12,619,769 | (479,803) | 12,139,966 |
| Regulatory balances | (a) | - | 825,162 | 825,162 |
| **Total assets and regulatory balances** | | $ 12,619,769 | $ 345,359 | $ 12,965,128 |
| **LIABILITIES** | | | | |
| **Current** | | | | |
| Payables and accruals | | $ 1,551,250 | $ - | $ 1,551,250 |
| Deferred revenue | | 4,932 | - | 4,932 |
| Town of Goderich demand loan | | 2,000,000 | - | 2,000,000 |
| Dividends payable | | 125,000 | - | 125,000 |
| Current portion - bank loan | | 132,312 | - | 132,312 |
| Current portion of customer deposits | | 50,000 | - | 50,000 |
| Total current liabilities | | 3,863,494 | - | 3,863,494 |
| Note payable | | 974,454 | - | 974,454 |
| Long-term debt | | 1,812,838 | - | 1,812,838 |
| Deferred revenue | (c) | - | 271,231 | 271,231 |
| Post-employment benefits | (b) | 233,527 | 80,746 | 314,273 |
| Customer deposits | | 98,606 | - | 98,606 |
| | | 3,119,425 | 351,977 | 3,471,402 |
| Future income taxes | (d) | 14,750 | (14,750) | - |
| Total liabilities | | 6,997,669 | 337,227 | 7,334,896 |
| **EQUITY** | | | | |
| Capital stock | | 3,410,092 | - | 3,410,092 |
| Retained earnings | | 2,212,008 | 24,875 | 2,236,883 |
| Other comprehensive income | (b) | - | (89,250) | (89,250) |
| Total liabilities and equity | | 12,619,769 | 272,852 | 12,892,621 |
| Regulatory balances | (a) | - | 72,507 | 72,507 |
| **Total liabilities, equity and regulatory balances** | | $ 12,619,769 | $ 345,359 | $ 12,965,128 |

The reconciliation of the statement of earnings and other comprehensive income from Canadian GAAP to IFRS is as follows:

| **Statement of Earnings and Other Comprehensive Income** For the year ended December 31, 2014 | **Notes** | **Canadian GAAP** | **Transitional Adjustments** | **IFRS** |
|---|---|---|---|---|
| **Revenue** | | | | |
| Sale of power | | $ 9,511,677 | $ - | $ 9,511,677 |
| Regulatory adjustment to sale of energy | (a) | - | 432,060 | 432,060 |
| Contributions in aid of construction | (c) | - | 3,147 | 3,147 |
| Other revenue | | 222,832 | - | 222,832 |
| Distribution | | 2,386,460 | - | 2,386,460 |
| | | 12,120,969 | 435,207 | 12,556,176 |
| **Cost of power** | | | | |
| Power purchased | | 9,511,677 | - | 9,511,677 |
| **Net distribution revenue** | | 2,609,292 | 435,207 | 3,044,499 |
| **Expenditures** | | | | |
| Administration and general | (b) | 797,064 | (24,875) | 772,189 |
| Amortization | (c) | 208,889 | 3,147 | 212,036 |
| Billing and collecting | | 423,956 | - | 423,956 |
| Operations | | 208,223 | - | 208,223 |
| Maintenance | | 266,708 | - | 266,708 |
| Community relations | | 13,949 | - | 13,949 |
| | | 1,918,789 | (21,728) | 1,897,061 |
| **Earnings from operations before the following** | | 690,503 | 456,935 | 1,147,438 |
| Finance income | | 204,987 | - | 204,987 |
| Finance charges | | (18,692) | - | (18,692) |
| **Net earnings before payments-in-lieu of taxes and regulatory items** | | 504,208 | 456,935 | 961,143 |
| Net movements in regulatory balances | (a) | - | (432,060) | (432,060) |
| **Net earnings before payments-in-lieu of taxes** | | 504,208 | 24,875 | 529,083 |
| Payments-in-lieu of taxes | | 27,952 | - | 27,952 |
| Future taxes | | 71,550 | - | 71,550 |
| | | 99,502 | - | 99,502 |
| **Net earnings for the year** | | 404,706 | 24,875 | 429,581 |
| Other comprehensive income | | - | - | - |
| **Total earnings and other comprehensive income for the year** | | $ 404,706 | $ 24,875 | $ 429,581 |

**a) Regulatory assets and liabilities**

IFRS 14 permits a rate-regulated entity to continue to apply its previous GAAP accounting policies for the recognition, measurement, impairment and derecognition of regulatory balances. All regulatory balances are required to be reclassified to a new separate section of the balance sheet with deferral accounts in debit balances separated from those with credit balances at year end. This transitional adjustment is a reclassification on the Balance Sheets and has no impact on the Statement of Changes in Shareholder's Equity or the Statement of Earnings and Other Comprehensive Income.

**b) Employee future benefits**

Under IFRS actuarial gains and losses arising from experience adjustments and changes in actuarial assumptions are recognized in other comprehensive income. These amounts are not reclassified in subsequent periods. Previously under Canadian GAAP, the utility amortized the excess of the net actuarial gains/losses over 10% of the accrued benefit obligation into the statements of earnings on a straight-line basis over the average remaining service life of its active employees. At the date of transition, all previously unamortized actuarial gains/losses were recognized in other comprehensive income. The impact of this recognition and measurement difference as at January 1, 2014 was an overall increase to the post-employment liability of $105,621 and a corresponding decrease to other comprehensive income. This adjustment also resulted in a decrease to operating expenses for 2014 of $24,975.

The Utility has elected to present its post-employment benefit liability as non-current as it is not expected to be settled wholly within twelve months.

**c) Contributions in aid of construction**

Under IFRS Contributions in Aid of Construction are treated as deferred revenue and are amortized as revenue on a straight-line basis over the useful life of the related constructed or contributed asset on the Statement of Earnings and Other Comprehensive Income. Previously under Canadian GAAP the Utility has offset these contributions against the cost of the constructed or contributed asset and reflected the amortization of the contribution as a reduction to depreciation expense on the Statement of Earnings. The impact of transition for the period ending December 31, 2014 was an increase in property, plant and equipment of $271,231 and a corresponding increase in deferred revenue.

**d) Deferred taxes**

The above noted changes have increased the deferred tax asset based on a tax rate of 15.5%.

The reconciliation of equity and comprehensive income as previously reported under Canadian GAAP to IFRS is as follows:

| | December 31, 2014 | January 1, 2014 |
|---|---|---|
| **Retained earnings as reported under GAAP** | $ 2,212,008 | $ 1,932,302 |
| Adjustments to retained earnings | | |
| Employee future benefits | 24,875 | - |
| **Retained earnings as reported under IFRS** | $ 2,236,883 | $ 1,932,302 |
| **Accumulated other comprehensive income as reported under Canadian GAAP** | $ - | $ - |
| Adjustments for transition | | |
| Employee future benefits | 105,621 | 105,621 |
| Deferred taxes | (16,371) | (16,371) |
| **Accumulated other comprehensive income as reported under IFRS** | $ 89,250 | $ 89,250 |
| **Share capital as reported under Canadian GAAP** | $ 3,410,092 | $ 3,410,092 |
| Adjustments for transition | - | - |
| **Share capital as reported under IFRS** | $ 3,410,092 | $ 3,410,092 |

# ATTACHMENT 11

# MERGED LDC PRO FORMA FINANCIAL STATEMENTS

ETPL, WCHE LDC Co.

| ASSETS | 2018 Combined Proforma |
|---|---|
| **Current Assets** | |
| Cash | 1,034,172 |
| Accounts Recievable | 5,926,838 |
| Due from Related Parties | 191,813 |
| Materials and supplies | 133,158 |
| Unbilled Revenue | 9,042,761 |
| Prepaid Expenses | 167,951 |
| Payments in lieu of tax | 45,202 |
| **Total Current assets** | 16,541,895 |
| | |
| **Non-current assets** | |
| Property, plant and equipment | 50,251,630 |
| Intangible Assets | 902,056 |
| Investments | 25,584 |
| **Total Non-current assets** | 51,179,270 |
| **Total Assets** | 67,721,165 |
| | |
| **Regulatory balances** | 8,874,654 |
| **Total assets and regulatory balances** | 76,595,819 |

| | |
|---|---|
| **Liabilities** | |
| **Current Liabilities** | |
| Accounts payable | 14,917,645 |
| Due to related parties | 776,078 |
| Long term debt due within one year | 2,897,898 |
| Customer deposits | 621,866 |
| Deferred Revenue | 692,724 |
| **Total current liabilities** | 19,906,211 |
| | |
| **Non-current liabilities** | |
| Long-term debt | 23,261,449 |
| Post-employment benefits | 1,244,061 |
| Customer deposits | 784,408 |
| Deferred revenue | 4,451,106 |
| Deferred tax liability | 329,409 |
| Total non-current liabilities | 30,070,433 |
| **Total liabilities** | 49,976,644 |
| | |
| **Equity** | |
| Share Capital | 14,265,677 |
| Retained Earnings | 8,642,086 |
| Accumulated other comprehensive loss | - 128,087 |
| **Total Equity** | 22,779,676 |
| **Total Liabilities and Equity** | 72,756,320 |
| | |
| Regulatory Balances | 3,839,499 |
| Total Liabilities Equity and regulatory balances | 76,595,819 |

**ETPL, WCHE LDC Co.**

| | **2018 Combined Proforma** |
|---|---|
| **Distribution Revenue** | 12,961,228 |
| **Service Revenue** | 604,448 |
| **Total Revenue from Operations** | 13,565,676 |
| **Expenses** | |
| Billing and collecting | 1,646,803 |
| Community relations | 37,726 |
| Direct Expenses | 4,377,208 |
| Office and administration | 1,471,583 |
| Regulatory and professional | 680,827 |
| | 8,214,147 |
| **Income from Operations** | **5,351,529** |
| | - |
| Amortization | 2,106,680 |
| Interest expense | 1,101,757 |
| Regulatory interest income | (62,059) |
| | 3,146,378 |
| **Income Before Income Tax** | **2,205,151** |
| **Payments in Lieu of Income Taxes** | |
| Current | 287,580 |
| Future tax benefit | |
| **Income Taxes** | 287,580 |
| **Net Income** | **1,917,571** |

# ATTACHMENT 12

# ERIE THAMES POWERLINES AND WEST COAST HURON ENERGY RATE ORDERS

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

# DECISION AND RATE ORDER

# EB-2016-0068

## ERIE THAMES POWERLINES CORPORATION

**Application for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2017.**

**By Delegation, Before: Lynne Anderson**

**March 30, 2017**

# 1 INTRODUCTION AND SUMMARY

This is the Decision and Rate Order (Decision) for Erie Thames Powerlines Corporation's Incentive Regulation Mechanism (IRM) application for 2017 rates.

Erie Thames Powerlines Corporation (Erie Thames Powerlines) serves about 18,000 mostly residential and commercial electricity customers in the municipalities of Aylmer, Port Stanley, Belmont, Ingersoll, Thamesford, Otterville, Norwich, Burgessville, Beachville, Embro, Tavistock, Clinton, Mitchell, and Dublin. The company is seeking the Ontario Energy Board's approval for the rates it charges to distribute electricity to its customers, as is required of licenced and rate-regulated distributors in Ontario.

Distributors may choose one of three Ontario Energy Board (OEB) rate-setting methods. Erie Thames Powerlines has selected the Price Cap Incentive Rate-setting (Price Cap IR) option that has a five-year term. Rates are set through a cost of service rebasing application for the first year and are adjusted mechanistically through an IRM application for each of the ensuing four years. The price cap adjustment is based on inflation and the OEB's assessment of a distributor's efficiency.

Erie Thames Powerlines filed an IRM application with the OEB on October 17, 2016 to seek approval for changes to its distribution rates to be effective May 1, 2017. Erie Thames Powerlines last appeared before the OEB with a cost of service rebasing application for 2012 rates in the EB-2012-0121 proceeding.

The OEB addresses the following issues with respect to Erie Thames Powerlines' IRM application in this Decision.

- Price Cap Adjustment
- Regulatory Charges
- Shared Tax Adjustments
- Retail Transmission Service Rates
- Group 1 Deferral and Variance Accounts
- Residential Rate Design
- Implementation and Order

Erie Thames Powerlines applied for a rate increase of 1.60% in accordance with the OEB-approved 2017 parameters for inflation and productivity. The 1.60% price cap adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes; it does not apply to the rates and charges listed in Schedule B.

Erie Thames Powerlines also applied to change the composition of its distribution service rates. Residential distribution service rates currently include a fixed monthly charge and a variable usage charge. In 2015, the OEB issued a policy to transition these rates to a fully fixed structure over a four-year period beginning in 2016.[1] Accordingly, the fixed monthly charge for 2017 has once again been adjusted upward in this Decision by more than the mechanistic adjustment alone. The variable usage rate is commensurately lower. This policy change does not affect the total revenue that distributors collect from residential customers.

This Decision on Erie Thames Powerlines' IRM application will result in a monthly bill decrease of $0.22 for a residential customer consuming 750 kWh.

The OEB approves the adjustments made to Erie Thames Powerlines' application, and the associated rates calculated, as a result of this proceeding.

# 2 THE PROCESS

Erie Thames Powerlines filed an application with the OEB on October 17, 2016 under section 78 of the OEB Act and under the OEB's Chapter 3 Filing Requirements for Incentive Rate-Setting Applications seeking approval for changes to its electricity distribution rates to be effective May 1, 2017.

The OEB follows a standard, streamlined process for IRM applications under Price Cap IR. This Decision is being issued by delegated authority under section 6 of the *Ontario Energy Board Act, 1998*.

The OEB first prepares a rate model that includes information from past proceedings and annual reporting requirements. The distributor then reviews and updates the model and includes it with its application.

Erie Thames Powerlines' IRM application was supported by written evidence and a completed rate model. Questions were asked and answers were provided by Erie Thames Powerlines through emails and phone calls. Based on this information, a decision was drafted and provided to Erie Thames Powerlines on February 14, 2017. Erie Thames Powerlines was given the opportunity to provide its comments on the draft for consideration prior to the OEB issuing this Decision.

[1] Board Policy: A New Distribution Rate Design for Residential Electricity Customers, EB-2012-0410, April 2, 2015

# 3 ORGANIZATION OF THE DECISION

The OEB has organized this Decision into sections to reflect the issues that were considered in making its findings.[2] Each section outlines the OEB's reasons for approving or denying the proposals included in the application and affecting 2017 rates. The last section addresses the steps to implement the final rates that flow from this Decision.

# 4 PRICE CAP ADJUSTMENT

The price cap adjustment follows an OEB-approved formula that includes annually updated components for inflation and the OEB's expectations of efficiency and productivity gains.[3] The formula is an *inflation minus X-factor* rate adjustment, which is intended to incent innovation and efficiency. The OEB has set the inflation factor for 2017 rates at 1.9% based on its established formula.[4]

The X-factors for individual distributors have two parts: a productivity element established from a historical analysis of industry cost performance; and a stretch factor based on a distributor's efficiency relative to its expected costs. Subtracting the X-factor from inflation ensures that rates decline in real, constant-dollar terms, providing distributors an incentive to improve efficiency or else experience declining net income.

Based on industry conditions over the historical study period, the productivity factor has been set at 0.0%. A stretch factor is assigned to each distributor based on the individual distributor's total cost performance as benchmarked relative to other distributors in Ontario. For Price Cap IR applications, there are five stretch factor groupings that have each been assigned a stretch factor in the range from 0.0% to 0.6%.[5] The most efficient distributor, based on the cost evaluation ranking, would be assigned the lowest stretch factor of 0.0%. Higher stretch factors are applied to distributors in accordance with their cost performance relative to expected levels, to reflect the incremental productivity gains that distributors are expected to achieve.

### Findings

The OEB assigned Erie Thames Powerlines a stretch factor of 0.30% based on the

[2] See list of issues in the Introduction, p.1
[3] Report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (December 4, 2013)
[4] As outlined in the Report cited at footnote 3 above
[5] Report to the Ontario Energy Board – "Empirical Research in Support of Incentive Rate-Setting: 2015 Benchmarking Update." Pacific Economics Group LLC. July 2016

updated benchmarking study for use for rates effective in 2017.[6] The resulting net price cap adjustment for Erie Thames Powerlines is 1.60% (i.e. 1.9% - (0% + 0.30%)).

The 1.60% adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes; it does not apply to the rates and charges listed in Schedule B.

# 5 REGULATORY CHARGES

Customers are charged a number of fees to cover the costs associated with various programs and wholesale market services.

The Rural or Remote Electricity Rate Protection (RRRP) program is designed to partially offset the relatively high cost of electricity distribution to eligible customers located in rural or remote areas of Ontario. The funding level is established by the government of Ontario and is recovered from all electricity customers in the province through a charge that is set annually by the OEB.

Wholesale market service (WMS) charges recover the cost of the services provided by the Independent Electricity System Operator (IESO) to operate the electricity system and administer the wholesale market. These charges may include costs associated with: operating reserve, system congestion and imports, and losses on the IESO-controlled grid. Distributors recover the WMS charges from their customers through the WMS kWh rate.

In addition, the costs of the IESO WMS Capacity Based Recovery (CBR) initiative are recovered by distributors from Class B customers through a separate kWh charge, and from Class A customers through their share of the actual CBR charge based on their contribution to peak demand.

These regulatory charges are components of the Regulatory Charge on customers' bills and are established annually by the OEB through a separate order.

The OEB has set the RRRP charge for 2017 at $0.0021 per kWh.

The WMS rate used by distributors to bill their Class A and B customers remains at $0.0032 per kWh. An additional component is billed to Class B customers for the CBR of $0.0004 per kWh.[7]

[6] As outlined in the Report cited at footnote 5 above
[7] Decision and Rate Order, EB-2016-0362, December 15, 2016

These changes are effective January 1, 2017 for all distributors as a result of the generic order that was part of a separate OEB decision.[8]

The Ontario Electricity Support Program (OESP) is a program to deliver on-bill rate assistance to low income electricity customers. This program was funded by all Ontario customers through the OESP Charge.

On March 23, 2017, the OEB issued a Decision and Order rescinding the OESP charge effective May 1, 2017[9] until further notice.

The OEB has updated the Tariff of Rates and Charges flowing from the above, listed in Schedule A, to reflect these changes. Although the OEB has also, for administrative convenience, removed the OESP credits from the attached tariff, distributors must continue until further notice to apply the OESP credits on bills issued to eligible low-income customers, as set by the OEB's December 21, 2016 Order.[10]

# 6 SHARED TAX ADJUSTMENTS

The OEB approves an amount for taxes in a distributor's cost of service proceeding based on the tax rates in place at the time. The OEB has determined that a 50/50 sharing of the impact of legislated tax changes between shareholders and ratepayers is appropriate in the period between cost of service proceedings. The shared tax change amount will be assigned to customer rate classes in the same proportions as the OEB-approved distribution revenue by rate class from a distributor's last cost of service proceeding.

The application identified a total tax change of $55,549, resulting in a shared amount of $27,775 to be charged to rate payers. Since the allocated tax sharing amount does not produce a rate rider in one or more rate classes the rate generator model does not compute rate riders and distributors are expected to transfer the entire OEB-approved tax sharing amount into account 1595 for disposition at a later date.[11] Erie Thames Powerlines has accordingly requested to record the amount in a deferral account for future disposition.[12]

[8] Ibid
[9] EB-2017-0135
[10] EB-2016-0376
[11] Chapter 3 Filing Requirements for Electricity Distribution Rate Applications, Appendix B
[12] Erie Thames Powerlines Corporation, Application filed October 17, 2016, Manager's Summary

### Findings

The OEB agrees with Erie Thames Powerlines request to record this amount in the variance account for future disposition. Accordingly, the OEB directs Erie Thames Powerlines to record the tax sharing of $27,775 in variance Account 1595 by June 30, 2017 for disposition at a future date.

# 7 RETAIL TRANSMISSION SERVICE RATES

Electricity distributors use Retail Transmission Service Rates (RTSRs) to pass along the cost of transmission service to their distribution customers. The RTSRs are adjusted annually to reflect the revised costs as calculated by the application of the current Uniform Transmission Rates (UTRs) to historical transmission deliveries. The UTRs are established annually by a separate OEB order. Partially embedded distributors, such as Erie Thames Powerlines, must also adjust their RTSRs to reflect any changes to the applicable RTSRs of their host distributor, which in this case is Hydro One Networks Inc. Distributors may apply to the OEB annually to approve the RTSRs they propose to charge their customers, as Erie Thames Powerlines has done in this application.

### Findings

The OEB approves the RTSRs as adjusted in this Application to reflect current applicable rates. The RTSRs are based on the previous years' UTRs as the OEB has not yet approved the adjustment of UTRs for 2017. The OEB has approved the 2017 Sub-Transmission Class RTSRs for Hydro One Networks Inc. to use for billing embedded distributors. These rate changes have been incorporated into the 2017 IRM Rate Generator Model (RTSR filing module) to adjust the RTSRs that Erie Thames Powerlines will charge its customers.[13] The differences between the previous and the new 2017 UTRs, once approved, will be captured in Accounts 1584 and 1586 for future disposition.

The applicable UTRs and Sub-Transmission Class RTSRs for Hydro One Networks Inc. are shown in the following tables:

[13] Rate Order, EB-2016-0081, issued December 21, 2016

**Current Applicable Uniform Transmission Rates**

| | |
|---|---|
| Network Service Rate | $3.66 per kW |
| <u>Connection Service Rates</u> | |
| Line Connection Service Rate | $0.87 per kW |
| Transformation Connection Service Rate | $2.02 per kW |

**2017 Sub-Transmission RTSRs**

| | |
|---|---|
| Network Service Rate | $3.19 per kW |
| <u>Connection Service Rates</u> | |
| Line Connection Service Rate | $0.77 per kW |
| Transformation Connection Service Rate | $1.75 per kW |

# 8 GROUP 1 DEFERRAL AND VARIANCE ACCOUNT BALANCES

Group 1 deferral and variance accounts (Group 1 accounts) track the differences between the costs that a distributor is billed for certain IESO and host distributor services (including the cost of power) and the associated revenues that the distributor receives from its customers for these services. The total net difference between these costs and revenues is disposed to customers through a temporary charge or credit known as a rate rider.

The OEB's policy[14] is to review and dispose of the distributor's Group 1 account balances if they exceed (as a debit or credit) the pre-set disposition threshold of $0.001 per kWh during the term of an incentive ratemaking plan. The distributor must justify why any account balance in excess of the threshold should not be disposed. The distributor may propose to dispose of balances below this threshold.

Erie Thames Powerlines' 2015 actual year-end total balance for Group 1 accounts including interest projected to April 30, 2017 is a debit of $39,783. This amount results

[14] Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (July 31, 2009)

in a total debit claim of $0.0001 per kWh, which does not exceed the preset disposition threshold. Erie Thames Powerlines did not seek disposition of balances in its application.

### Findings

The OEB finds that no disposition is required at this time as the disposition threshold has not been exceeded.

## 9 RESIDENTIAL RATE DESIGN

All residential distribution rates currently include a fixed monthly charge and a variable usage charge. The OEB residential rate design policy[15] stipulates that electricity distributors will transition residential customers to a fully fixed monthly distribution service charge over a four-year period starting in 2016. The OEB requires that distributors filing IRM applications this year continue with this transition by once again adjusting their distribution rates to increase the fixed monthly service charge and decrease the variable charge consistent with the policy.

The OEB expects the applicant to apply two tests to evaluate whether mitigation (generally a lengthening of the transition period) for customers in the transition is required. The first test is to calculate the change in the monthly fixed charge and to consider mitigation if it exceeds $4. The second is to calculate the total bill impact of the proposals in the application for low volume residential customers (defined as those residential RPP customers whose consumption is at the 10$^{th}$ percentile for the class). Mitigation may be required if the bill impact related to the application exceeds 10% for these customers.

Erie Thames Powerlines’ implementation of the transition results in an increase to the fixed charge prior to the price cap adjustment of $3.47. The bill impacts arising from the proposals in this application, including the fixed rate change, are below 10% for low volume residential customers.

### Findings

The OEB finds that the proposed 2017 increase to the monthly fixed charge is in accordance with the OEB's residential rate design policy. The results of the monthly fixed charge and total bill impact for low consumption residential consumers show that

[15] Ibid page 2

no mitigation is required. The OEB approves the increase as proposed by the applicant and calculated in the final rate model.

# 10 IMPLEMENTATION AND ORDER

### Rate Model

This Decision and Rate Order is accompanied by a rate model, applicable supporting model and a Tariff of Rates and Charges (Schedule A). Entries in the models were reviewed to ensure that they are in accordance with Erie Thames Powerlines' EB-2012-0121 cost of service decision, and that the 2016 OEB-approved Tariff of Rates and Charges as well as the cost, revenue and consumption results from 2015 are as reported by Erie Thames Powerlines to the OEB. The rate model was adjusted, where applicable, to correct any discrepancies.

**THE ONTARIO ENERGY BOARD ORDERS THAT**

1. The Tariff of Rates and Charges set out in Schedule A of this Decision and Rate Order is approved effective May 1, 2017 for electricity consumed or estimated to have been consumed on and after such date. Erie Thames Powerlines Corporation shall notify its customers of the rate changes no later than the delivery of the first bill reflecting the new rates.

**ADDRESS**

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

E-mail: boardsec@oeb.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

**DATED** at Toronto, March 30, 2017

**ONTARIO ENERGY BOARD**

*Original Signed By*

Kirsten Walli
Board Secretary

**Schedule A**

**To Decision and Rate Order**

**Tariff of Rates and Charges**

**OEB File No: EB-2016-0068**

**DATED: March 30, 2017**

# Erie Thames Powerlines Corporation
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0068**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to customers residing in residential dwelling units. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 23.22 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0094 |
| Low Voltage Service Rate | $/kWh | 0.0021 |
| Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018 Applicable only for Non-RPP Customers | $/kWh | 0.0074 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0063 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0056 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Erie Thames Powerlines Corporation
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0068**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to General Service buildings requiring a connection with a connected load less than 50 kW, and, Town Houses and Condominiums described in section 3.1.9 of the Distributor's Conditions of Service that require centralized bulk metering. General Service buildings are defined as buildings that are used for purposes other than single family dwellings. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 22.29 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0145 |
| Low Voltage Service Rate | $/kWh | 0.0020 |
| Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018 Applicable only for Non-RPP Customers | $/kWh | 0.0074 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0059 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0052 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Erie Thames Powerlines Corporation
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0068**

## GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to General Service customers requiring a connection with a connected load, or whose average monthly maximum demand used for billing purposes, is equal to or greater than 50 kW but less than 1000 kW. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 127.91 |
| Distribution Volumetric Rate | $/kW | 3.1024 |
| Low Voltage Service Rate | $/kW | 0.7099 |
| Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018 Applicable only for Non-RPP Customers | $/kW | 2.2875 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6482 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.8703 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Erie Thames Powerlines Corporation

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2017

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

**EB-2016-0068**

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

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than 1000 kW but less than 5000 kW. Class A and Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing

### APPLICATION

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

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

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

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 2,537.23 |
| Distribution Volumetric Rate | $/kW | 4.2161 |
| Low Voltage Service Rate | $/kW | 0.7635 |
| Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018 Applicable only for Non-RPP Customers | $/kW | 3.6800 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8748 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.0036 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Erie Thames Powerlines Corporation

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2017

**This schedule supersedes and replaces all previously**

**approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0068**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or great than, 5000 kW. Class A and Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 10,362.66 |
| Distribution Volumetric Rate | $/kW | 1.9046 |
| Low Voltage Service Rate | $/kW | 0.0733 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.1869 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.2727 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Erie Thames Powerlines Corporation

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2017

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

**EB-2016-0068**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 3.20 |
| Distribution Volumetric Rate | $/kWh | 0.1142 |
| Low Voltage Service Rate | $/kWh | 0.0020 |
| Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018 Applicable only for Non-RPP Customers | $/kWh | 0.0074 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0059 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0052 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Erie Thames Powerlines Corporation
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0068**

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 5.59 |
| Distribution Volumetric Rate | $/kW | 15.6727 |
| Low Voltage Service Rate | $/kW | 0.5482 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0441 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.4388 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Erie Thames Powerlines Corporation

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2017

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

**EB-2016-0068**

## STREET LIGHTING SERVICE CLASSIFICATION

This Classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connection load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 4.04 |
| Distribution Volumetric Rate | $/kW | 23.5048 |
| Low Voltage Service Rate | $/kW | 0.5482 |
| Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018 | | |
| Applicable only for Non-RPP Customers | $/kW | 2.7392 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.0441 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.3780 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Erie Thames Powerlines Corporation

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2017

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

**EB-2016-0068**

## EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification refers to an electricity distributor licensed by the Ontario Energy Board that is provided electricity by means of this distributors' facilities. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 2,361.50 |
| Distribution Volumetric Rate | $/kW | 4.0623 |
| Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018 Applicable only for Non-RPP Customers | $/kW | 3.4671 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.8460 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.6423 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# Erie Thames Powerlines Corporation
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously**
**approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0068**

## microFIT SERVICE CLASSIFICATION

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

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

# Erie Thames Powerlines Corporation

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2017

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

**EB-2016-0068**

## ALLOWANCES

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

## SPECIFIC SERVICE CHARGES

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

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

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

### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Easement letter | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Returned cheque (plus bank charges) | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late payment - per month | % | 1.50 |
| Late payment - per annum | % | 19.56 |
| Collection of account charge - no disconnection - during regular business hours | $ | 30.00 |
| Collection of account charge - no disconnection - after regular hours | $ | 165.00 |
| Disconnect/reconnect at meter - during regular hours | $ | 65.00 |
| Disconnect/reconnect at meter - after regular hours | $ | 185.00 |
| Disconnect/reconnect at pole - during regular hours | $ | 185.00 |

### Other

| | | |
|---|---|---|
| Temporary service - install & remove - overhead - no transformer | $ | 500.00 |
| Temporary service - install & remove - underground - no transformer | $ | 300.00 |
| Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments) | $ | 22.35 |

# Erie Thames Powerlines Corporation

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2017

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

**EB-2016-0068**

## RETAIL SERVICE CHARGES (if applicable)

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

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

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

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

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

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

## LOSS FACTORS

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

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0451 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0161 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0347 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0060 |

**Schedule B**

**To Decision and Rate Order**

**List of Rates and Charges Not Affected by the Price Cap or Annual IR Index**

**OEB File No: EB-2016-0068**

**DATED: March 30, 2017**

The following rates and charges are not affected by the Price Cap or Annual IR Index:

- Rate riders
- Rate adders
- Low voltage service charges
- Retail transmission service rates
- Wholesale market service rate
- Rural or remote electricity rate protection charge
- Standard supply service – administrative charge
- Transformation and primary metering allowances
- Loss factors
- Specific service charges
- microFIT charge
- Retail service charges

Ontario Energy Board
Commission de l’énergie de l’Ontario

# DECISION AND RATE ORDER

## EB-2016-0112

## WEST COAST HURON ENERGY INC.

**Application for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2017.**

**By Delegation, Before: Theodore Antonopoulos**

**March 30, 2017**

# 1 INTRODUCTION AND SUMMARY

This is the Decision and Rate Order (Decision) for West Coast Huron Energy Inc.'s Incentive Regulation Mechanism (IRM) application for 2017 rates.

West Coast Huron Energy Inc. (West Coast Huron Energy) serves about 3,800 mostly residential and commercial electricity customers in the Town of Goderich. The company is seeking the Ontario Energy Board's approval for the rates it charges to distribute electricity to its customers, as is required of licenced and rate-regulated distributors in Ontario.

Distributors may choose one of three Ontario Energy Board (OEB) rate-setting methods. West Coast Huron Energy has selected the Price Cap Incentive Rate-setting (Price Cap IR) option that has a five-year term. Rates are set through a cost of service rebasing application for the first year and are adjusted mechanistically through an IRM application for each of the ensuing four years. The price cap adjustment is based on inflation and the OEB's assessment of a distributor's efficiency.

West Coast Huron Energy filed an IRM application with the OEB on November 7, 2016 to seek approval for changes to its distribution rates to be effective May 1, 2017. West Coast Huron Energy last appeared before the OEB with a cost of service rebasing application for 2013 rates in the EB-2012-0275 proceeding.

The OEB addresses the following issues with respect to West Coast Huron Energy's IRM application in this Decision.

- Price Cap Adjustment
- Regulatory Charges
- Shared Tax Adjustments
- Retail Transmission Service Rates
- Group 1 Deferral and Variance Accounts
- Residential Rate Design
- Implementation and Order

West Coast Huron Energy applied for a rate increase of 1.30% in accordance with the OEB-approved 2017 parameters for inflation and productivity. The 1.30% price cap adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes; it does not apply to the rates and charges listed in Schedule B.

West Coast Huron Energy also applied to change the composition of its distribution service rates. Residential distribution service rates currently include a fixed monthly charge and a variable usage charge. In 2015, the OEB issued a policy to transition these rates to a fully fixed structure over a four-year period beginning in 2016.[1] Accordingly, the fixed monthly charge for 2017 has once again been adjusted upward in this Decision by more than the mechanistic adjustment alone. The variable usage rate is commensurately lower. This policy change does not affect the total revenue that distributors collect from residential customers.

This Decision on West Coast Huron Energy's IRM application will result in a monthly bill increase of $0.58 for a residential customer consuming 750 kWh.

The OEB approves the adjustments made to West Coast Huron Energy's application, and the associated rates calculated, as a result of this proceeding.

# 2 THE PROCESS

West Coast Huron Energy filed an application with the OEB on November 7, 2016 under section 78 of the OEB Act and under the OEB’s Chapter 3 Filing Requirements for Incentive Rate-Setting Applications seeking approval for changes to its electricity distribution rates to be effective May 1, 2017.

The OEB follows a standard, streamlined process for IRM applications under Price Cap IR. This Decision is being issued by delegated authority under section 6 of the *Ontario Energy Board Act, 1998*.

The OEB first prepares a rate model that includes information from past proceedings and annual reporting requirements. The distributor then reviews and updates the model and includes it with its application.

West Coast Huron Energy's IRM application was supported by written evidence and a completed rate model. Questions were asked and answers were provided by West Coast Huron Energy through emails and phone calls. Based on this information, a decision was drafted and provided to West Coast Huron Energy on February 13, 2017. West Coast Huron Energy was given the opportunity to provide its comments on the draft for consideration prior to the OEB issuing this Decision.

[1] Board Policy: A New Distribution Rate Design for Residential Electricity Customers, EB-2012-0410, April 2, 2015

# 3 ORGANIZATION OF THE DECISION

The OEB has organized this Decision into sections to reflect the issues that were considered in making its findings.[2] Each section outlines the OEB's reasons for approving or denying the proposals included in the application and affecting 2017 rates. The last section addresses the steps to implement the final rates that flow from this Decision.

# 4 PRICE CAP ADJUSTMENT

The price cap adjustment follows an OEB-approved formula that includes annually updated components for inflation and the OEB's expectations of efficiency and productivity gains.[3] The formula is an *inflation minus X-factor* rate adjustment, which is intended to incent innovation and efficiency. The OEB has set the inflation factor for 2017 rates at 1.9% based on its established formula.[4]

The X-factors for individual distributors have two parts: a productivity element established from a historical analysis of industry cost performance; and a stretch factor based on a distributor's efficiency relative to its expected costs. Subtracting the X-factor from inflation ensures that rates decline in real, constant-dollar terms, providing distributors an incentive to improve efficiency or else experience declining net income.

Based on industry conditions over the historical study period, the productivity factor has been set at 0.0%. A stretch factor is assigned to each distributor based on the individual distributor's total cost performance as benchmarked relative to other distributors in Ontario. For Price Cap IR applications, there are five stretch factor groupings that have each been assigned a stretch factor in the range from 0.0% to 0.6%.[5] The most efficient distributor, based on the cost evaluation ranking, would be assigned the lowest stretch factor of 0.0%. Higher stretch factors are applied to distributors in accordance with their cost performance relative to expected levels, to reflect the incremental productivity gains that distributors are expected to achieve.

[2] See list of issues in the Introduction, p.1
[3] Report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (December 4, 2013)
[4] As outlined in the Report cited at footnote 3 above
[5] Report to the Ontario Energy Board – "Empirical Research in Support of Incentive Rate-Setting: 2015 Benchmarking Update." Pacific Economics Group LLC. July 2016

**Findings**

The OEB assigned West Coast Huron Energy a stretch factor of 0.60% based on the updated benchmarking study for use for rates effective in 2017.[6] The resulting net price cap adjustment for West Coast Huron Energy is 1.30% (i.e. 1.9% - (0% + 0.60%)).

The 1.30% adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes; it does not apply to the rates and charges listed in Schedule B.

# 5 REGULATORY CHARGES

Customers are charged a number of fees to cover the costs associated with various programs and wholesale market services.

The Rural or Remote Electricity Rate Protection (RRRP) program is designed to partially offset the relatively high cost of electricity distribution to eligible customers located in rural or remote areas of Ontario. The funding level is established by the government of Ontario and is recovered from all electricity customers in the province through a charge that is set annually by the OEB.

Wholesale market service (WMS) charges recover the cost of the services provided by the Independent Electricity System Operator (IESO) to operate the electricity system and administer the wholesale market. These charges may include costs associated with: operating reserve, system congestion and imports, and losses on the IESO-controlled grid. Distributors recover the WMS charges from their customers through the WMS kWh rate.

In addition, the costs of the IESO WMS Capacity Based Recovery (CBR) initiative are recovered by distributors from Class B customers through a separate kWh charge, and from Class A customers through their share of the actual CBR charge based on their contribution to peak demand.

These regulatory charges are components of the Regulatory Charge on customers' bills and are established annually by the OEB through a separate order.

The OEB has set the RRRP charge for 2017 at $0.0021 per kWh.

[6] As outlined in the Report cited at footnote 5 above

The WMS rate used by distributors to bill their Class A and B customers remains at $0.0032 per kWh. An additional component is billed to Class B customers for the CBR of $0.0004 per kWh.[7]

These changes are effective January 1, 2017 for all distributors as a result of the generic order that was part of a separate OEB decision.[8]

The Ontario Electricity Support Program (OESP) is a program to deliver on-bill rate assistance to low income electricity customers. This program was funded by all Ontario customers through the OESP Charge.

On March 23, 2017, the OEB issued a Decision and Order rescinding the OESP charge effective May 1, 2017[9] until further notice.

The OEB has updated the Tariff of Rates and Charges flowing from the above, listed in Schedule A, to reflect these changes. Although the OEB has also, for administrative convenience, removed the OESP credits from the attached tariff, distributors must continue until further notice to apply the OESP credits on bills issued to eligible low-income customers, as set by the OEB's December 21, 2016 Order.[10]

# 6 SHARED TAX ADJUSTMENTS

The OEB approves an amount for taxes in a distributor's cost of service proceeding based on the tax rates in place at the time. The OEB has determined that a 50/50 sharing of the impact of legislated tax changes between shareholders and ratepayers is appropriate in the period between cost of service proceedings. The shared tax change amount will be assigned to customer rate classes in the same proportions as the OEB-approved distribution revenue by rate class from a distributor's last cost of service proceeding.

The application identified a total tax change of $1,018, resulting in a shared amount of $509 to be distributed to rate payers. Since the allocated tax sharing amount does not produce a rate rider in one or more rate classes the rate generator model does not compute rate riders and distributors are required to transfer the entire OEB-approved

[7] Decision and Rate Order, EB-2016-0362, December 15, 2016
[8] Ibid
[9] EB-2017-0135
[10] EB-2016-0376

tax sharing amount into account 1595 for disposition at a later date. [11]

**Findings**

The OEB directs West Coast Huron Energy to record the tax sharing of $509 in variance Account 1595 by June 30, 2017 for disposition at a future date.

# 7 RETAIL TRANSMISSION SERVICE RATES

Electricity distributors use Retail Transmission Service Rates (RTSRs) to pass along the cost of transmission service to their distribution customers. The RTSRs are adjusted annually to reflect the revised costs as calculated by the application of the current Uniform Transmission Rates (UTRs) to historical transmission deliveries. The UTRs are established annually by a separate OEB order. Distributors may apply to the OEB annually to approve the RTSRs they propose to charge their customers, as West Coast Huron Energy has done in this application.

**Findings**

The OEB approves the RTSRs as adjusted in this Application to reflect current applicable rates. The RTSRs are based on the previous years' UTRs as the OEB has not yet approved the adjustment of UTRs for 2017. The differences between the previous and the new 2017 UTRs, once approved, will be captured in Accounts 1584 and 1586 for future disposition. The current applicable UTRs are shown in the following table:

**Current Applicable Uniform Transmission Rates**

| | |
|---|---|
| Network Service Rate | $3.66 per kW |
| Connection Service Rates | |
| Line Connection Service Rate | $0.87 per kW |
| Transformation Connection Service Rate | $2.02 per kW |

[11] Chapter 3 Filing Requirements for Electricity Distribution Rate Applications, Appendix B

# 8 GROUP 1 DEFERRAL AND VARIANCE ACCOUNT BALANCES

Group 1 deferral and variance accounts (Group 1 accounts) track the differences between the costs that a distributor is billed for certain IESO and host distributor services (including the cost of power) and the associated revenues that the distributor receives from its customers for these services. The total net difference between these costs and revenues is disposed to customers through a temporary charge or credit known as a rate rider.

The OEB's policy[12] is to review and dispose of the distributor's Group 1 account balances if they exceed (as a debit or credit) the pre-set disposition threshold of $0.001 per kWh during the term of an incentive ratemaking plan. The distributor must justify why any account balance in excess of the threshold should not be disposed. The distributor may propose to dispose of balances below this threshold.

West Coast Huron Energy's 2015 actual year-end total balance for Group 1 accounts including interest projected to April 30, 2017 is a debit of $118,047. This amount results in a total debit claim of $0.0008 per kWh, which does not exceed the preset disposition threshold. West Coast Huron Energy did not seek disposition of balances in its application.

**Findings**

The OEB finds that no disposition is required at this time as the disposition threshold has not been exceeded.

# 9 RESIDENTIAL RATE DESIGN

All residential distribution rates currently include a fixed monthly charge and a variable usage charge. The OEB residential rate design policy[13] stipulates that electricity distributors will transition residential customers to a fully fixed monthly distribution service charge over a four-year period starting in 2016. The OEB requires that distributors filing IRM applications this year continue with this transition by once again adjusting their distribution rates to increase the fixed monthly service charge and decrease the variable charge consistent with the policy.

[12] Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (July 31, 2009)
[13] Ibid page 2

The OEB expects the applicant to apply two tests to evaluate whether mitigation (generally a lengthening of the transition period) for customers in the transition is required. The first test is to calculate the change in the monthly fixed charge, and to consider mitigation if it exceeds $4. The second is to calculate the total bill impact of the proposals in the application for low volume residential customers (defined as those residential RPP customers whose consumption is at the $10^{th}$ percentile for the class). Mitigation may be required if the bill impact related to the application exceeds 10% for these customers.

West Coast Huron Energy's implementation of the transition results in an increase to the fixed charge prior to the price cap adjustment of $3.72. The bill impacts arising from the proposals in this application, including the fixed rate change, are below 10% for low volume residential customers.

### Findings

The OEB finds that the proposed 2017 increase to the monthly fixed charge is in accordance with the OEB's residential rate design policy. The results of the monthly fixed charge, and total bill impact for low consumption residential consumers show that no mitigation is required. The OEB approves the increase as proposed by the applicant and calculated in the final rate model.

## 10 IMPLEMENTATION AND ORDER

### Rate Model

This Decision and Rate Order is accompanied by a rate model, applicable supporting models and a Tariff of Rates and Charges (Schedule A). Entries in the models were reviewed to ensure that they are in accordance with West Coast Huron Energy's EB-2012-0275 cost of service decision, and that the 2016 OEB-approved Tariff of Rates and Charges as well as the cost, revenue and consumption results from 2015 are as reported by West Coast Huron Energy to the OEB. The rate model was adjusted, where applicable, to correct any discrepancies.

**THE ONTARIO ENERGY BOARD ORDERS THAT**

1. The Tariff of Rates and Charges set out in Schedule A of this Decision and Rate Order is approved effective May 1, 2017 for electricity consumed or estimated to have been consumed on and after such date. West Coast Huron Energy Inc. shall notify its customers of the rate changes no later than the delivery of the first bill reflecting the new rates.

## ADDRESS

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

E-mail: boardsec@oeb.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

**DATED** at Toronto, March 30, 2017

**ONTARIO ENERGY BOARD**

*Original Signed By*

Kirsten Walli
Board Secretary

**Schedule A**

**To Decision and Rate Order**

**Tariff of Rates and Charges**

**OEB File No: EB-2016-0112**

**DATED: March 30, 2017**

# West Coast Huron Energy Inc.

## TARIFF OF RATES AND CHARGES

**Effective and Implementation Date May 1, 2017**

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

**EB-2016-0112**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to customers residing in residential dwelling units. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 25.65 |
| Rate Rider for Recovery of Stranded Meter Assets - effective until August 31, 2017 | $ | 0.80 |
| Rate Rider for Recovery of Storm Damage Costs - effective until August 31, 2017 | $ | 1.17 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0116 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0067 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0058 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0112**

## GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW and, Town Houses and Condominiums described in section 3.1.8 of the distributor's Conditions of Service that require centralized bulk metering. General Service Buildings are defined as buildings that are used for purposes other than single family dwellings. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 32.17 |
| Rate Rider for Recovery of Stranded Meter Assets - effective until August 31, 2017 | $ | 2.05 |
| Rate Rider for Recovery of Storm Damage Costs - effective until August 31, 2017 | $ | 3.02 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0110 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0061 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0051 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.

## TARIFF OF RATES AND CHARGES

**Effective and Implementation Date May 1, 2017**

**This schedule supersedes and replaces all previously**

**approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0112**

## GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION

This classification applies to the supply of electrical energy to General Service Customers requiring a connection with a connected load, whose average monthly maximum demand used, for billing purposes, is, or is forecast to be, equal to or greater than 50 kW but less than 500 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 154.18 |
| Rate Rider for Recovery of Storm Damage Costs - effective until August 31, 2017 | $ | 28.87 |
| Distribution Volumetric Rate | $/kW | 2.4101 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.4325 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.0569 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously**
**approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0112**

## GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to the supply of electrical energy to General Service Customers requiring a connection with a connected load, whose average monthly maximum demand used, for billing purposes, is, or is forecast to be, equal to or greater than 500 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 1,635.23 |
| Rate Rider for Recovery of Storm Damage Costs - effective until August 31, 2017 | $ | 188.72 |
| Distribution Volumetric Rate | $/kW | 1.1222 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.5836 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.2551 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0112**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 9,836.55 |
| Rate Rider for Recovery of Storm Damage Costs - effective until August 31, 2017 | $ | 985.78 |
| Distribution Volumetric Rate | $/kW | 1.7707 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.8610 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.5785 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0112**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, decorative street lighting, bill boards, etc. The level of consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 75.26 |
| Rate Rider for Recovery of Storm Damage Costs - effective until August 31, 2017 | $ | 6.00 |
| Distribution Volumetric Rate | $/kWh | 0.0668 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0061 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0051 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously**
**approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0112**

## SENTINEL LIGHTING SERVICE CLASSIFICATION
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 36.89 |
| Rate Rider for Recovery of Storm Damage Costs - effective until August 31, 2017 | $ | 1.46 |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.8446 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.6233 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0112**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connection load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Street lighting plant, facilities or equipment owned by the customer are subject to the ESA requirements. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 4.51 |
| Rate Rider for Recovery of Storm Damage Costs - effective until August 31, 2017 | $ | 0.16 |
| Distribution Volumetric Rate | $/kW | 24.6893 |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.8346 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.6233 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously**
**approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0112**

## microFIT SERVICE CLASSIFICATION

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

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

# West Coast Huron Energy Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2017

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

**EB-2016-0112**

## ALLOWANCES

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

## SPECIFIC SERVICE CHARGES

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

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

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

### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 15.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

### Non-Payment of Account

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

### Other

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

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2017
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2016-0112**

## RETAIL SERVICE CHARGES (if applicable)

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

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

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

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

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

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

## LOSS FACTORS

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

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0467 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0362 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0045 |

**Schedule B**

**To Decision and Rate Order**

**List of Rates and Charges Not Affected by the Price Cap or Annual IR Index**

**OEB File No: EB-2016-0112**

**DATED: March 30, 2017**

The following rates and charges are not affected by the Price Cap or Annual IR Index:

- Rate riders
- Rate adders
- Low voltage service charges
- Retail transmission service rates
- Wholesale market service rate
- Rural or remote electricity rate protection charge
- Standard supply service – administrative charge
- Transformation and primary metering allowances
- Loss factors
- Specific service charges
- microFIT charge
- Retail service charges

# Erie Thames Powerlines Corporation

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2017

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

**EB-2017-0038**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to customers residing in residential dwelling units. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

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

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

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

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

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 29.3700 |
| Distribution Volumetric Rate | $/kWh | 0.0053 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.7900 |
| Rate Rider for the Disposition of Group 1 Variance Accounts Excluding GA Applicable to RPP customers Effective unitl April 30th 2019 | $/kWh | 0.0008 |
| Rate Rider for the Disposition of Group 1 Variance Accounts GA applicable to Non-RPP customers only Effective unitl April 30th 2019 | $/kWh | 0.0065 |
| Rate Rider for Account 1580 sub-account CBDR Class B Effective until April 30th 2019 | $/kWh | 0.0003 |
| Rate rider for recovery of LRAM account 1568 Effective until April 30th 2019 | $/kWh | 0.0007 |
| Rate Rider for the Disposition of Group 2 Variance Accounts Effective unitl April 30th 2019 | $ | 0.4700 |
| Rate Rider for the Disposition of CGAAP to IFRS Transition Variance Accounts Effective unitl April 30th 2019 | $ | (1.4498) |
| Low Voltage Service Rate | $/kWh | 0.0021 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0053 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0048 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |

| | | |
|---|---|---|
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to General Service buildings requiring a connection with a connected load less than 50 kW, and, Town Houses and Condominiums described in section 3.1.9 of the Distributor's Conditions of Service that require centralized bulk metering. General Service buildings are defined as buildings that are used for purposes other than single family dwellings. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

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

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

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

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

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 26.95 |
| Distribution Volumetric Rate | $/kWh | 0.0175 |
| Low Voltage Service Rate | $/kWh | 0.0020 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Rate Rider for the Disposition of Group 1 Variance Accounts Excluding GA Applicable to RPP customers Effective unitl April 30th 2019 | $/kWh | 0.0010 |
| Rate Rider for the Disposition of Group 1 Variance Accounts GA applicable to Non-RPP customers only Effective unitl April 30th 2019 | $/kWh | 0.0065 |
| Rate Rider for Account 1580 sub-account CBDR Class B Effective until April 30th 2019 | $/kWh | 0.0003 |
| Rate rider for recovery of LRAM account 1568 Effective until April 30th 2019 | $/kWh | 0.0019 |
| Rate Rider for the Disposition of Group 2 Variance Accounts Effective unitl April 30th 2019 | $/kWh | 0.0007 |
| Rate Rider for the Disposition of CGAAP to IFRS Transition Variance Accounts Effective unitl April 30th 2019 | $/kWh | -0.0022 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0050 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0045 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to General Service customers requiring a connection with a connected load, or whose average monthly maximum demand used for billing purposes, is equal to or greater than 50 kW but less than 1000 kW. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

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

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

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

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

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 82.28 |
| Distribution Volumetric Rate | $/kW | 2.0674 |
| Low Voltage Service Rate | $/kW | 0.7099 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Rate Rider for the Disposition of Group 1 Variance Accounts Excluding GA Applicable to RPP customers Effective unitl April 30th 2019 | $/kW | 0.5968 |
| Rate Rider for the Disposition of Group 1 Variance Accounts GA applicable to Non-RPP customers only Effective unitl April 30th 2019 | $/kWh | 0.0065 |
| Rate Rider for Account 1580 sub-account CBDR Class B Effective until April 30th 2019 | $/kW | 0.1124 |
| Rate rider for recovery of LRAM account 1568 Effective until April 30th 2019 | $/kW | 0.1663 |
| Rate Rider for the Disposition of Group 2 Variance Accounts Effective unitl April 30th 2019 | $/kW | 0.2909 |
| Rate Rider for the Disposition of CGAAP to IFRS Transition Variance Accounts Effective unitl April 30th 2019 | $/kW | -0.8988 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.2471 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.6037 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

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

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than 1000 kW but less than 5000 kW determined on a Gross Load Basis. Class A and Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service. For those customers who install behind the meter generation they will be billed on a Gross Load basis for the distribution variable charge.

**APPLICATION**

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

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

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

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 2,537.23 |
| Distribution Volumetric Rate | $/kW | 2.5270 |
| Low Voltage Service Rate | $/kW | 0.7635 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Rate Rider for the Disposition of Group 1 Variance Accounts Excluding GA Applicable to RPP customers Effective unitl April 30th 2019 | $/kWh | 0.1511 |
| Rate Rider for the Disposition of Group 1 Variance Accounts GA applicable to Non-RPP customers only Effective unitl April 30th 2019 | $/kWh | 0.0065 |
| Rate Rider for Account 1580 sub-account CBDR Class B Effective until April 30th 2019 | $/kW | 0.0786 |
| Rate rider for recovery of LRAM account 1568 Effective until April 30th 2019 | $/kW | 0.6700 |
| Rate Rider for the Disposition of Group 2 Variance Accounts Effective unitl April 30th 2019 | $/kW | 0.2035 |
| Rate Rider for the Disposition of CGAAP to IFRS Transition Variance Accounts Effective unitl April 30th 2019 | $/kW | -0.6287 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.4394 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.7180 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |

| | | |
|---|---|---|
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# LARGE USE SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or great than, 5000 kW. Class A and Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

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

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

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

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 10,362.66 |
| Distribution Volumetric Rate | $/kW | 2.5716 |
| Low Voltage Service Rate | $/kW | 0.0733 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Rate Rider for the Disposition of Group 1 Variance Accounts Excluding GA Applicable to RPP customers Effective unitl April 30th 2019 | $/kW | 0.4350 |
| Rate rider for recovery of LRAM account 1568 Effective until April 30th 2019 | $/kW | 0.5789 |
| Rate Rider for the Disposition of Group 2 Variance Accounts Effective unitl April 30th 2019 | $/kW | 0.4303 |
| Rate Rider for the Disposition of CGAAP to IFRS Transition Variance Accounts Effective unitl April 30th 2019 | $/kW | -1.3296 |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.7042 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.9488 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

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

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

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

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

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 2.10 |
| Distribution Volumetric Rate | $/kWh | 0.0749 |
| Low Voltage Service Rate | $/kWh | 0.0020 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Rate Rider for the Disposition of Group 1 Variance Accounts Excluding GA Applicable to RPP customers Effective unitl April 30th 2019 | $/kWh | -0.0007 |
| Rate Rider for the Disposition of Group 1 Variance Accounts GA applicable to Non-RPP customers only Effective unitl April 30th 2019 | $/kWh | 0.0065 |
| Rate Rider for Account 1580 sub-account CBDR Class B Effective until April 30th 2019 | $/kWh | 0.0003 |
| Rate Rider for the Disposition of Group 2 Variance Accounts Effective unitl April 30th 2019 | $/kWh | 0.0007 |
| Rate Rider for the Disposition of CGAAP to IFRS Transition Variance Accounts Effective unitl April 30th 2019 | $/kWh | -0.0022 |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0050 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0045 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

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

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

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

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

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 12.31 |
| Distribution Volumetric Rate | $/kWh | 0.0893 |
| Low Voltage Service Rate | $/kWh | 0.0018 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Rate Rider for the Disposition of Group 1 Variance Accounts Excluding GA Applicable to RPP customers Effective unitl April 30th 2019 | $/kWh | -0.0007 |
| Rate Rider for the Disposition of Group 1 Variance Accounts GA applicable to Non-RPP customers only Effective unitl April 30th 2019 | $/kWh | 0.0065 |
| Rate Rider for Account 1580 sub-account CBDR Class B Effective until April 30th 2019 | $/kWh | 0.0003 |
| Rate Rider for the Disposition of Group 2 Variance Accounts Effective unitl April 30th 2019 | $/kWh | 0.0007 |
| Rate Rider for the Disposition of CGAAP to IFRS Transition Variance Accounts Effective unitl April 30th 2019 | $/kWh | -0.0022 |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.7345 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.2337 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# STREET LIGHTING SERVICE CLASSIFICATION

This Classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connection load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

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

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

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

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

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 2.25 |
| Distribution Volumetric Rate | $/kW | 13.1162 |
| Low Voltage Service Rate | $/kW | 0.5482 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Rate Rider for the Disposition of Group 1 Variance Accounts Excluding GA Applicable to RPP customers Effective unitl April 30th 2019 | $/kW | 0.4878 |
| Rate Rider for the Disposition of Group 1 Variance Accounts GA applicable to Non-RPP customers only Effective unitl April 30th 2019 | $/kWh | 0.0065 |
| Rate Rider for Account 1580 sub-account CBDR Class B Effective until April 30th 2019 | $/kW | 0.0980 |
| Rate rider for recovery of LRAM account 1568 Effective until April 30th 2019 | $/kW | -19.0371 |
| Rate Rider for the Disposition of Group 2 Variance Accounts Effective unitl April 30th 2019 | $/kW | 0.2537 |
| Rate Rider for the Disposition of CGAAP to IFRS Transition Variance Accounts Effective unitl April 30th 2019 | $/kW | -0.7839 |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.7345 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.0391 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification refers to an electricity distributor licensed by the Ontario Energy Board that is provided electricity by means of this distributors' facilities. Further servicing details are available in the distributor's Conditions of Service.

**APPLICATION**

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

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

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

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

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 978.34 |
| Distribution Volumetric Rate | $/kW | 1.6829 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Rate Rider for the Disposition of Group 1 Variance Accounts Excluding GA Applicable to RPP customers Effective unitl April 30th 2019 | $/kW | 0.2881 |
| Rate Rider for the Disposition of Group 1 Variance Accounts GA applicable to Non-RPP customers only Effective unitl April 30th 2019 | $/kWh | 0.0065 |
| Rate Rider for Account 1580 sub-account CBDR Class B Effective until April 30th 2019 | $/kW | 0.1207 |
| Rate rider for recovery of LRAM account 1568 Effective until April 30th 2019 | $/kW | -0.0324 |
| Rate Rider for the Disposition of Group 2 Variance Accounts Effective unitl April 30th 2019 | $/kW | 0.3125 |
| Rate Rider for the Disposition of CGAAP to IFRS Transition Variance Accounts Effective unitl April 30th 2019 | $/kW | 0.9656 |
| Retail Transmission Rate - Network Service Rate | $/kW | 3.2635 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.2657 |

**MONTHLY RATES AND CHARGES - Regulatory Component**

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - Not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0021 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# microFIT SERVICE CLASSIFICATION

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

**APPLICATION**

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

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

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

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

**MONTHLY RATES AND CHARGES - Delivery Component**

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.60) |
| Primary Metering Allowance for Transformer Losses - applied to measured demand & energy | % | (1.00) |

# SPECIFIC SERVICE CHARGES

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

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

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

## Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Easement Letter | $ | 15.00 |
| Credit reference/credit check (plus credit agency costs) | $ | 15.00 |
| Returned Cheque (plus bank charges) | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 30.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

## Non-Payment of Account

| | | |
|---|---|---|
| Late Payment - per month | % | 1.50 |
| Late Payment - per annum | % | 19.56 |
| Collection of account charge - no disconnection - during regular business hours | $ | 30.00 |
| Collection of account charge - no disconnection - after regular hours | $ | 165.00 |
| Disconnect/Reconnect at Meter - during regular hours | $ | 65.00 |
| Disconnect/Reconnect at Meter - after regular hours | $ | 185.00 |
| Disconnect/Reconnect at Pole - during regular hours | $ | 185.00 |

## Other

| | | |
|---|---|---|
| Temporary service - install & remove - overhead - no transformer | $ | 500.00 |
| Temporary service - install & remove - underground - no transformer | $ | 300.00 |
| Specific charge for access to the power poles - $/pole/year | $ | 22.35 |

(with the exception of wireless attachments)

# RETAIL SERVICE CHARGES (if applicable)

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

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

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

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

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

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

## LOSS FACTORS

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

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0338 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0142 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0380 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0042 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2018
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0083**

## RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to customers residing in residential dwelling units. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 29.77 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0059 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | 0.0022 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0031) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0068 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0058 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2018
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0083**

# GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW and, Town Houses and Condominiums described in section 3.1.8 of the distributor's Conditions of Service that require centralized bulk metering. General Service Buildings are defined as buildings that are used for purposes other than single family dwellings. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 32.59 |
| Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018 | $ | 0.79 |
| Distribution Volumetric Rate | $/kWh | 0.0111 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | 0.0022 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0031) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0062 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0051 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2018
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0083**

## GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION

This classification applies to the supply of electrical energy to General Service Customers requiring a connection with a connected load, whose average monthly maximum demand used, for billing purposes, is, or is forecast to be, equal to or greater than 50 kW but less than 500 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 156.18 |
| Distribution Volumetric Rate | $/kW | 2.4414 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | 0.0022 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (1.0320) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.4759 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.0412 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2018

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

**EB-2017-0083**

## GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to the supply of electrical energy to General Service Customers requiring a connection with a connected load, whose average monthly maximum demand used, for billing purposes, is, or is forecast to be, equal to or greater than 500 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 1,656.49 |
| Distribution Volumetric Rate | $/kW | 1.1368 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | 0.0022 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (1.3396) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.6297 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.2379 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2018
**This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors**

**EB-2017-0083**

## LARGE USE SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 9,964.43 |
| Distribution Volumetric Rate | $/kW | 1.7937 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (0.1168) |
| Retail Transmission Rate - Network Service Rate | $/kW | 2.9121 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 2.5588 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2018

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

**EB-2017-0083**

## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, decorative street lighting, bill boards, etc. The level of consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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

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

### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 76.24 |
| Distribution Volumetric Rate | $/kWh | 0.0677 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kWh | (0.0030) |
| Retail Transmission Rate - Network Service Rate | $/kWh | 0.0062 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kWh | 0.0051 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

## SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 37.37 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (1.3832) |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.8763 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.6119 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2018
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**EB-2017-0083**

## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connection load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Street lighting plant, facilities or equipment owned by the customer are subject to the ESA requirements. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 4.57 |
| Distribution Volumetric Rate | $/kW | 25.0103 |
| Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers | $/kWh | 0.0022 |
| Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 | $/kW | (1.3400) |
| Retail Transmission Rate - Network Service Rate | $/kW | 1.8674 |
| Retail Transmission Rate - Line and Transformation Connection Service Rate | $/kW | 1.6109 |

### MONTHLY RATES AND CHARGES - Regulatory Component

| | | |
|---|---|---|
| Wholesale Market Service Rate (WMS) - not including CBR | $/kWh | 0.0032 |
| Capacity Based Recovery (CBR) - Applicable for Class B Customers | $/kWh | 0.0004 |
| Rural or Remote Electricity Rate Protection Charge (RRRP) | $/kWh | 0.0003 |
| Standard Supply Service - Administrative Charge (if applicable) | $ | 0.25 |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
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**EB-2017-0083**

## microFIT SERVICE CLASSIFICATION
This classification applies to an electricity generation facility contracted under the Independant Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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### MONTHLY RATES AND CHARGES - Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.40 |

# West Coast Huron Energy Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2018

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**EB-2017-0083**

## ALLOWANCES

| | | |
|---|---|---|
| Transformer Allowance for Ownership - per kW of billing demand/month | $/kW | (0.60) |
| Primary Metering Allowance for Transformer Losses - applied to measured demand & energy | % | (1.00) |

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
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**EB-2017-0083**

## SPECIFIC SERVICE CHARGES

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### Customer Administration

| | | |
|---|---|---|
| Arrears certificate | $ | 15.00 |
| Account set up charge/change of occupancy charge (plus credit agency costs if applicable) | $ | 30.00 |
| Special meter reads | $ | 15.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $ | 30.00 |

### Non-Payment of Account

| | | |
|---|---|---|
| Late Payment - per month | % | 1.50 |
| Late Payment - per annum | % | 19.56 |
| Collection of account charge - no disconnection | $ | 30.00 |
| Disconnect/Reconnect at Meter - during regular hours | $ | 65.00 |
| Disconnect/Reconnect at Meter - after regular hours | $ | 185.00 |
| Disconnect/Reconnect at Pole - during regular hours | $ | 185.00 |

### Other

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

# West Coast Huron Energy Inc.
## TARIFF OF RATES AND CHARGES
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**EB-2017-0083**

## RETAIL SERVICE CHARGES (if applicable)

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

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

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

# West Coast Huron Energy Inc.

## TARIFF OF RATES AND CHARGES

### Effective and Implementation Date May 1, 2018

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**EB-2017-0083**

## LOSS FACTORS

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

| | |
|---|---|
| Total Loss Factor - Secondary Metered Customer < 5,000 kW | 1.0467 |
| Total Loss Factor - Secondary Metered Customer > 5,000 kW | 1.0145 |
| Total Loss Factor - Primary Metered Customer < 5,000 kW | 1.0362 |
| Total Loss Factor - Primary Metered Customer > 5,000 kW | 1.0045 |