Exhibit 1:

ADMINISTRATIVE DOCUMENTS

Exhibit 1: Administrative Documents

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Exhibit 1: Administrative Documents

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EXECUTIVE SUMMARY

This rate application is the second application following the amalgamation of Erie Thame Power Lines Corporation, Clinton Power Corporation and West Perth Power Inc. Since that amalgamation ETPL has continued to evolve to address the changing expectations and demands of our customers, the IESO and the Ontario Energy Board and the province. We have invested in our people and our infrastructure to improve the customer experience while maintaining below inflation increases. In the event that ETPL had not been successful in merging West Perth and Clinton into its operation customers would have been paying approximately $400,000 extra in operating costs annually due to efficiencies passed on to customers through the 2012 Cost of Service Application EB-2012-0121. This has resulted in $2,400,000 in savings between Cost of Service Applications.

ETPL is a **L**ocal **D**istribution **C**ompany currently servicing 18,500 customers in 14 communities across 4 counties, a partner you can count on. Our service territory stretches over 200 km from Port Stanley to Clinton. Serving the communities of Port Stanley, Aylmer, Belmont, Ingersoll, Thamesford, Embro, Beachville, Norwich, Otterville, Burgessville, Mitchell, Dublin and Clinton. In these communities, ETPL's diverse customer base ranges from individual residences to large commercial and industrial users, including the General Motors CAMI Automotive Assembly plant located in Ingersoll.

Managing Growth

ETPL has, and will continue to invest in its infrastructure to add customers, reduce losses, and improve power quality, safety and reliability. ETPL's asset management is continuing to improve as we introduce new technology, (GIS, SCADA, OMS) and access higher skilled employees. ETPL has done this while improving the financial metrics of the corporation.

During the past 5 years, ETPL has invested in plant and equipment consistent with the forecasted spending in EB-2012-0121. Furthermore ETPL has continued to invest at the approved level from its 2012 application despite the change in 2013 to IFRS Capitalization Policy that removed overhead costs from its capitalized amounts. Major infrastructure improvements included the substation transformer replacements at Tavistock MS1 and Aylmer MS1 along with the removal of one municipal substation in the town of Clinton which were all well beyond their useful life. In additional a new breaker position has been acquired at the Hydro One owned Aylmer transformer station to service the Town of Aylmer that will allow the town to be wholly supplied by the TS to further improve reliability and minimize losses. Major conversion projects to bring as much of ETPL's distribution system up to 27.6 kV from 4 and 8 kV are continually being engineered and constructed to improve reliability performance, system losses and eliminate end of useful life assets which will eventually eliminate a wide array of substations with various distribution voltages creating inefficiencies within our LDC. These projects are critical as they will prevent massive future expenditures that ETPL would require as these aging substations begin to fail.

Safety & Reliability

Safety is job number one for ETPL, for its employees, customer and the community as a whole. ETPL has made significant investment in training its staff and implementing Health and Safety policies and practices that meet or exceed the ESA and Workwell standards. ETPL has also invested heavily in technology to provide the necessary information to further safeguard our employees and the public to better interrupt what is happening on the distribution system. ETPL is dedicated to providing its customers with safe and reliable electricity while keeping energy efficiency top of mind. ETPL strives to provide added benefit and value through its innovation and technology and continuous improvement efforts; constantly seeking ways we can improve our services to meet or customer's needs.

Rate Application Summary:

ETPL is requesting an increase to its revenue requirement of $990,175 over its 2012 Board Approved amounts to be recovered from its customers in order to continue to provide safe reliable electricity that meets the needs of all of its stakeholders. This revenue requirement of $10,297,392 is an 11% increase since 2012 or 1.8% increase per year. While this application is based upon a forward test year the increase applied for is more in line with a typical IRM application in that the deficiency between revenue at current approved rates and applied for revenue requirement is only a 1.6% change. There are many drivers for this change such as the change in amortization from CGAAP in 2012 to IFRS in 2018, the change in working capital allowance calculator from 13% to 7.5%, and the change in income taxes recovered in rates to more appropriately reflect current tax practice applied in 2015 and 2016.

The Rate Base that underpins this application has increased by almost $9,000,000 since 2012 levels and has been primarily driven by reinvestment in ETPL's infrastructure. Since 2012 ETPL expects to have added $18,000,000 in assets (which translates to an increase in NBV of $8,700,000) to replace and refurbish its aging infrastructure in a very specific and planned manner. ETPL continues to employ a rigorous Asset Management program that is based upon the principles learned through its relationship with Oncor Utilities and TXU. This regiment firmly underpins ETPL's DSP and serves as the cornerstone of ETPL's operation.

ETPL is pleased to report that the resulting total bill impacts as a result of its application have a negligible impact upon its customer base with the largest monthly impact $4.30 per month for a GS<50 using 2,000 kWh's. ETPL is focused on ensuring value for its customers and has worked hard to mitigate impacts to its customers in this application and continues to strive for improvements and efficiencies in all aspects of its operation.

Exhibit 1: Administrative Documents

Tab 3 (of 11): Administration

ADMINISTRATION

1.3.1 Legal Application

IN THE MATTER OF the Ontario Energy Board Act, 1998, 5.0. 1998, c.15, 3 Schedule B, as amended ("the OEB Act");

AND IN THE MATTER OF an Application by Erie Thames Powerlines Corporation under Section 78 of the OEB Act to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2018. (this "Application")

Applicant's Name: Erie Thames Powerlines Corporation
(the "Applicant" or "ETPL").

ETPL is a fully licensed distributor of electricity under distribution licence ED-2002-0516 (Attachment 1-B) issued by the Ontario Energy Board (the "OEB" or the "Board") under the Ontario Electricity Board Act, 1998 (the "Act").

ETPL hereby applies to the Board pursuant to section 78 of the Act for an Order or Orders approving or fixing just and reasonable distribution rates effect May 1, 2018.

This application is made in accordance with the Board's Chapter 2 of the Board's Filing Requirements for Transmission and Distribution applications dated July 20, 2017. ETPL accordingly applies to the Board for the following:

- An Order approving ETPL's proposed tariff sheet for the 2018 rate year or other rates as the Board finds just and reasonable for the final rates effective May 1, 2018;
- An Order to approve clearance of the balances recorded in certain deferral and variance accounts by means of rate riders effective May 1, 2018;
- An Order to approve ETPL's Distribution System Plan as filed as part of this Application.

1.3.2 Certification of Evidence

Erie Thames Powerlines, Certification of Evidence is attached as Attachment 1-C.

1.3.3 Contact Information

Erie Thames Powerlines Corporation

Address:	143 Bell Street, P.O. Box 157 Ingersoll, Ontario N5C 3K5
Phone:	(519) 485-1820
Toll-Free:	1-877-850-3128
Fax:	(519) 485-5838
E-mail:	oeb@eriethamespower.com

Primary Application Contact

Please address all communication in this matter to:

Mr. Graig Pettit

Director of Regulatory, Finance, and Customer Relations

Phone: 519-485-1820 x 254

E-mail: oeb@eriethamespower.com

Other Contacts

Mr. Chris White

President and CEO

Phone: 519-485-1820 x 235

E-mail: cwhite@eriethamespower.com

Mr. Scott Brooks

Director of Operations and Risk
Phone: 519-485-1820 x 239
E-mail: sbrooks@eriethamespower.com

Mr. Chuck deJong
Director of Engineering and Innovation
Phone: 519-485-1820 x 230
E-mail: cdejong@eriethamespower.com

1.3.4 Identification of Legal Representation

ETPL is represented by Aird & Berlis LLP in this Application.

Legal Counsel:

Scott Stoll
Partner
Aird & Berlis LLP
Brookfield Place, 181 Bay Street, Suite 1800
Toronto, On
M5J 2T9
Telephone: 416-865-4703
Email: sstoll@airdberlis.com

1.3.5 Applicant's Internet and Social Media Addresses

The Application and related materials will be posted on the ETPL website, and will be available for viewing at the following internet address: http://www.eriethamespower.com/your-utility/regulatory/

The Application will further be communicated to customers via Facebook and Twitter.

ETPL's website and social media addresses are as follows:

Website: www.eriethamespower.com
Twitter (General): http://twitter.com/ETPowerlines
Twitter (Outages)*: http://twitter.com/ETPLOutages
Facebook: http://www.facebook.com/ErieThamesPowerlines

*The Outages Twitter account (@ETPLOutages) auto-populates messages that are instantaneously posted to the Erie Thames Powerlines website and Facebook account for quickly broadcasting outage information on a variety of platforms.

The Application will also be available on the Ontario Energy Board's website at www.oeb.ca under Board File Number EB-2017-0038.

1.3.6 Customer Impact Statements and Publication

All Customers in the ETPL service territory described below in section 1.4.1 who receive electricity distribution services from ETPL will be affected by this Application.

ETPL will follow the Board's instructions regarding the Publication of Notice in relation to this Application. ETPL proposes to publish the Notice of Application in the London Free Press on a Saturday. This is the major publication that has the greatest potential to reach the greatest number of ETPL's customers across its diverse geographical service territory. Alternatively, if directed by the OEB, ETPL would publish notices related to the Application in the following newspapers, however ETPL feels this would be a much more costly approach:

- Ingersoll Times – weekly
- Norwich Gazette – weekly
- Mitchell Advocate – weekly
- Clinton News Record – weekly
- St. Thomas Times-Journal – daily
- Aylmer Express – weekly

These are the major publications within each of ETPL's communities it services.

1.3.7 Bill Impacts

ETPL carefully weighed the impact on customer bills prior to completing this application. The proposed impacts are outlined in the chart below as well the detailed Bill Impact Model is included as Attachment 1-O in this Exhibit.

Bill Impact Summary

Rate Class	Billing Determinant	2017 Bill Amount	Proposed 2018 Bill Amount	Difference	Total Bill Impact
Residential RPP	233	$ 53.33	$ 57.23	$ 3.90	7.31%
Residential Non-RPP	233	$ 62.02	$ 65.62	$ 3.60	5.80%
Residential Non-RPP	800	$ 151.61	$ 150.76	-$ 0.85	-0.56%
Residential RPP	1000	$ 145.04	$ 143.89	-$ 1.15	-0.79%
Residential RPP	500	$ 85.26	$ 87.40	$ 2.14	2.51%
Residential RPP	750	$ 115.15	$ 115.64	$ 0.49	0.43%
GS<50 kw RPP	2000	$ 287.08	$ 290.80	$ 3.72	1.30%
GS<50 kw RPP	1000	$ 155.79	$ 160.09	$ 4.30	2.76%
GS<50 kw RPP	5000	$ 680.97	$ 682.91	$ 1.94	0.28%
GS>50 to 999 kW	100	$ 10,709.27	$ 10,111.55	-$ 597.72	-5.58%
GS>50 to 999 kW	1250	$139,050.29	$129,483.27	-$ 9,567.02	-6.88%
Large Use	12350	$677,395.66	$619,487.07	-$57,908.59	-8.55%
USL	150	$ 47.91	$ 39.86	-$ 8.05	-16.80%
Sentinel Lighting	150	$ 663.00	$ 572.25	-$ 90.75	-13.69%
Street Lighting	1	$ 133.49	$ 115.79	-$ 17.70	-13.26%
Embedded Distributor	660	$ 16,472.58	$ 9,849.20	-$ 6,623.38	-40.21%

1.3.8 Hearing Request

Erie Thames Powerlines Corporation requests that this Application be completed by way of a written hearing in order to expedite the proceeding. At this time ETPL has made allotments in its budget assuming a written hearing. Should the Board decide to proceed with an oral hearing in this manner, ETPL will respectfully request to amend the forecast to incorporate the incremental consultants', intervenor, OEB costs and legal fees, as well as travel and other expenses related with attendance at and preparation for an Oral Hearing into the Regulatory One-time Costs.

1.3.9 Requested Effective Date

ETPL requests that the Board make its Rate Order effective May 1, 2018 in accordance with the Filing Requirements.

In the event that the OEB is not able to provide a Decision and Rate Order in time for ETPL to implement its rates effective May 1, 2018, ETPL requests that the OEB declare ETPL's current rates interim effective May 1, 2018 and approve rate riders to recover the incremental revenue between the implementation date of the OEB's 2018 Rate Order and May 1, 2018.

1.3.10 Deviation Statements

ETPL has not, to the best of its knowledge, deviated from the final Boards' Filing Requirements for Electricity Distribution Rate Applications. ETPL has used the final models available for the 2018 COS application filers.

1.3.11 Methodology Changes

The methodologies used in this Application are generally consistent with the Chapter 2 Filing Requirements for Cost of Service rate applications published by the OEB on July 20, 2017.

1.3.12 Monthly Billing

Per the Minimum Filing Requirements the OEB requires a statement confirming that the distributor will have implemented monthly billing for all customers by December 31, 2016 pursuant to the OEB's April 15, 2015 DSC amendment.

ETPL confirms that it has billed its customers monthly, since prior to deregulation in 2000.

1.3.13 OEB Directions from Previous Decisions/Orders

ETPL does not have any Board Directives from its previous Cost of Service Application or from other Regulatory proceedings.

1.3.14 Conditions of Service

The current version of ETPL's Conditions of Service is available on its website at: http://www.eriethamespower.com/wp-content/uploads/2015/06/Conditions-of-Service-Version-6-2-Revised-January-2012.pdf and is included in this Exhibit as Attachment 1-D.

ETPL confirms that there are no rates and charges in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges.

ETPL is in the process of updating its' Conditions of Service and expect to file an updated version before this Application is approved.

1.3.15 Organizational Structure

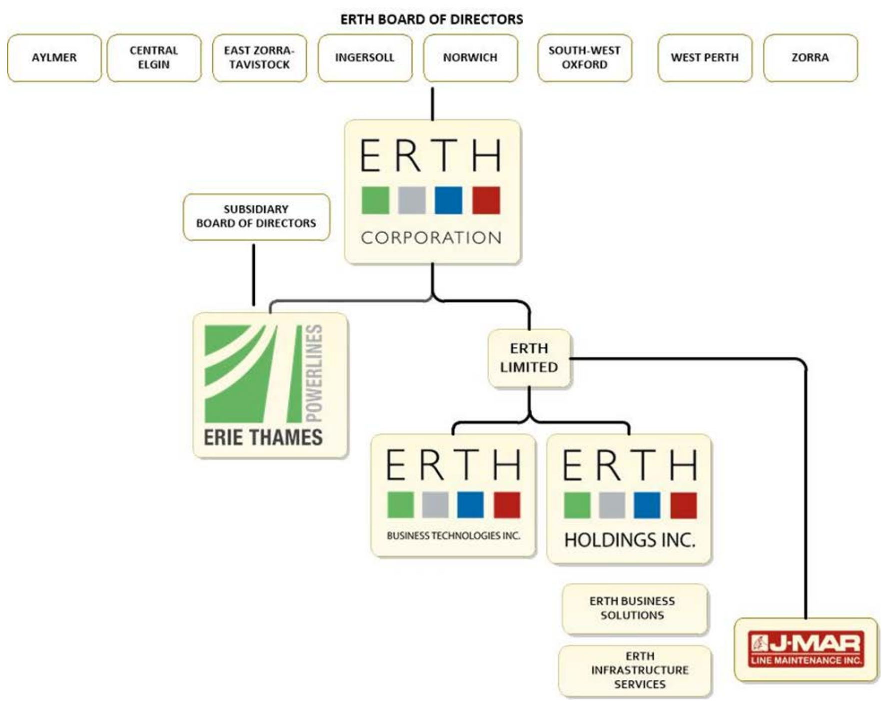
Erie Thames Powerlines Corporation grew out of the amalgamation of seven public utility commissions in 2000. The amalgamation was in response to the changing regulations in the Ontario electricity distribution market at that time. The smaller utilities knew they would gain significant efficiencies through the amalgamation, however, it was agreed upon that no employee would lose their job. In order to ensure both job guarantees and efficiencies, a non-regulated services division was created. Over the years, this grew into ERTH Corporation ("ERTH") and its subsidiary companies, which includes Erie Thames Powerlines Corporation.

ERTH is owned by eight municipal shareholders, each of which has equal representation on the ERTH Board of Directors and equal voting power. Each member of the ERTH Board of Directors is appointed by his/her own municipality. The ERTH Board of Directors is responsible for overseeing and monitoring the business and affairs of ERTH Corporation.

Erie Thames Powerlines Corporation maintains its own Board of Directors separate from the ERTH Board. The ETPL Board is specifically responsible for overseeing the business and affairs of Erie Thames Powerlines Corporation. Of the four (4) directors on the ETPL Board, one (1) is represented by ERTH's Chief Financial Officer, while the other three (3) are independent. This more than meets the OEB's policy to ensure that a minimum of one third of directors are independent. Each year, the Board of Directors establishes a schedule of meetings for the upcoming fiscal year. Generally, 4 meetings are held each fiscal year. The Meeting schedule for 2017 is as follows:

- February 23, 2017
- April 27, 2017
- September 7, 2017
- November 16, 2017

Pictured below is the organization chart for ERTH Corporation and how the respective businesses align.



ERTH Corporation:

ERTH Corporation is owned by eight municipal shareholders each with equal voting power and board representation. ERTH Corporation is headquartered at 180 Whiting Street in Ingersoll, Ontario.

Erie Thames Powerlines Corporation:

Erie Thames Powerlines Corporation (ETPL) is a licensed distribution company (LDC) wholly-owned by ERTH Corporation. As previously mentioned, ETPL was formed out of the amalgamation of seven public utilities commissions in 2000. In 2011, ETPL merged with West Perth Power and Clinton Power, which extended ETPL's service territory. ETPL owns, operates, and manages all distribution assets and is responsible for the safe, reliable transmission of power throughout its service territory. ETPL's main office is located at 143 Bell Street in Ingersoll, Ontario. To better serve the large territory, ETPL also has operations centres in Aylmer and Mitchell, Ontario. The Mission, Vision, and Values Statement for ETPL are as follows:

- *Mission: A community partner committed to delivering safe and reliable electricity while providing innovative and high-quality services and solutions to our customers.*
- *Vision: Working co-operatively as a trusted, quality services and solutions provider; creating value for all stakeholders.*
- *Values Statement:*
    - *Putting Safety First*
    - *Sustainability*
    - *Protecting the Environment*
    - *Strive for Operational and Performance Excellence*
    - *Leader in Quality Innovation and Customer Care*
    - *Committed to our Employees and Community Partnerships*

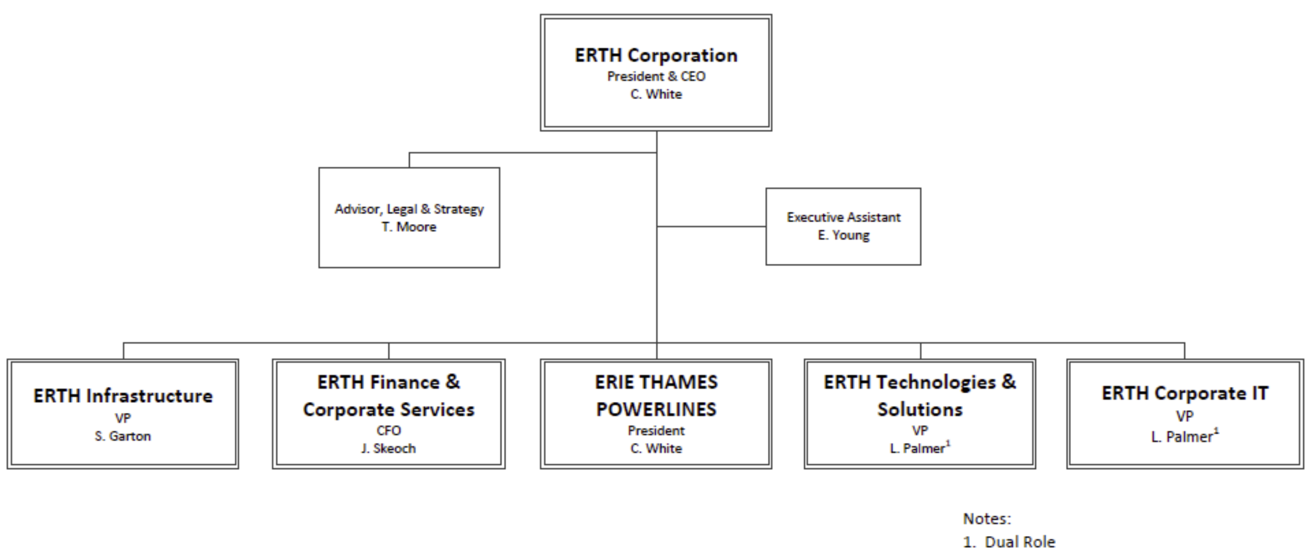
ERTH Limited:

ERTH Limited is the holding company for two subsidiary companies:

- **ERTH Business Technologies Inc. (EBT):** EBT is a software and technology service provider located at 154 University Avenue in Toronto, Ontario. EBT was formerly known as SPi, and developed the hub and spoke infrastructure following the deregulation of the Ontario electricity market.

- **ERTH (Holdings) Inc. (EHI):** EHI is headquartered at 180 Whiting Street in Ingersoll with other offices at 295 Wolfe Street in London, Ontario and 277 King Street in Thorndale, Ontario. There are two primary divisions of EHI: ERTH Infrastructure Services (EIS) and ERTH Business Solutions (EBS). EIS (including J-MAR) provides a variety of construction services including street lighting and traffic signals, utility construction, accredited meter verification, meter service provider, and substation and high voltage services. EBS provides back office services including utility billing, bill print and stuff, customer information systems, software development, and more.

Erie Thames Powerlines Corporation is represented on the ERTH Executive Management Team as shown below.



There are no planned legal or organizational changes for the structure of ERTH or Erie Thames Powerlines at this time. Attached in Attachment 1-E is Erie Thames Powerlines Corporation's organizational chart showing all ETPL employees and how they fit within the company.

1.3.16 Approvals Requested

ETPL's list of requested approvals is outlined in the table below and has been filed in the live excel model

Appendix 2-A.

Erie Thames Powerlines Corporation is seeking the following approvals in this application:	
1	Approval to charge distribution rates effective May 1st, 2018 to recover a revenue requirement of $10,785,164 utilizing the proposed rates detailed in Exhibit 8.
2	Approval of ETPL's distribution system plan as provided in Attachment 2 C of Exhibit 2.
3	Approval for updated Retail Transmission Rates as detailed in Exhibit 8 and the Excel RTSR workform
4	Approval of the revised loss factors as detailed in Exhibit 8
5	Approval of Wholesale Market Service Rates (with CBDR Split) and revised Rural and Remote Rate Protection Charges as detailed in Exhibit 8
6	Approval to continue billing Specific Service Charges, Retail Service Charges and Transformer Ownership Allowances as approved in ETPL's 2017 IRM application EB-2016-0068.
7	Approval to dispose of Group 1, Group 2 and Other DVA accounts as detailed in Exhibit 9.
8	Approval to continue the transition of residential rates to fully fixed charges as detailed in Exhibit 8

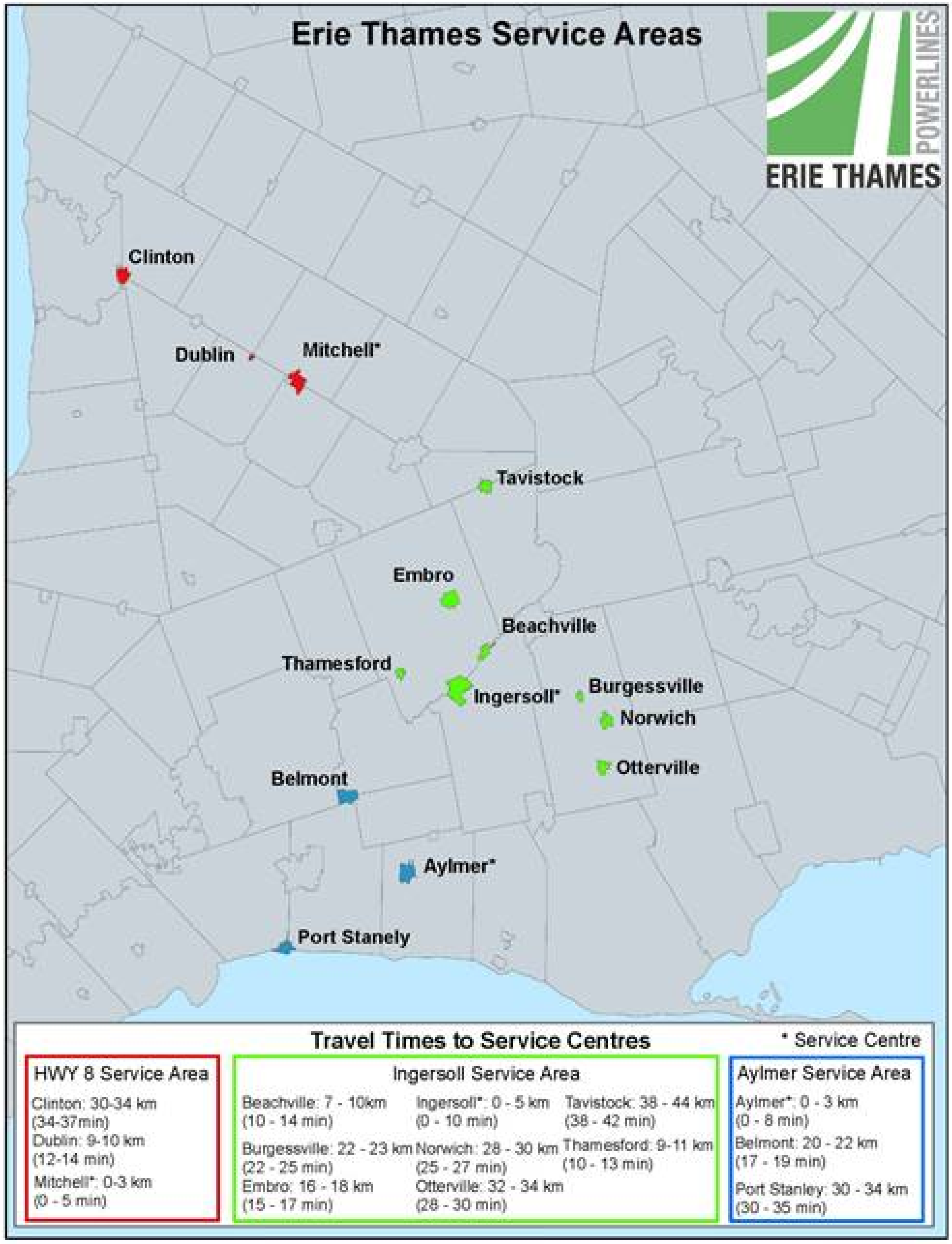
DISTRIBUTION SYSTEM OVERVIEW

1.3.1 Service Area

Erie Thames Powerlines Corporation services over 19,000 customers in an area that stretches from Port Stanley to Clinton, Ontario. The 14 towns serviced by Erie Thames Powerlines are:

- Aylmer
- Beachville
- Belmont
- Burgessville
- Clinton
- Dublin
- Embro
- Ingersoll
- Mitchell
- Norwich
- Otterville
- Port Stanley
- Tavistock
- Thamesford

To service this large area effectively, there are service centres located in Aylmer, Ingersoll, and Mitchell. The locations serviced by each service centre and the time to reach each town are noted in the service area map below.



<u>Ingersoll Operations Centre and Headquarters:</u>

The largest community served by ETPL is the Town of Ingersoll, which has a population of nearly 13,000. ETPL's head office and operations centre is located at 143 Bell Street in Ingersoll, which is geographically centered in ETPL's service territory. There are 37 full-time staff stationed at this location including senior management, call centre and billing, engineering, operations, health and safety, and administration. As outlined in the map above, this operations centre primarily serves customers located in Beachville, Burgessville, Embro, Ingersoll, Norwich, Otterville, Tavistock, and Thamesford. Large customers in this area include General Motors of Canada – CAMI (Ingersoll), Saputo Dairy Products of Canada GP (Tavistock), Maple Leaf Foods Inc. (Thamesford), and Ontario Refrigerated Services (Ingersoll).

Aylmer Operations Centre:

Aylmer, Ontario is the second largest town serviced by ETPL with a population of more than 7,000. The operations centre located at 280 Elm Street in Aylmer, employs 4 full-time staff and services customers located in Aylmer, Port Stanley, and Belmont. Some of the largest electricity users in this region include IGPC Ethanol Inc. (Aylmer), Elgin Innovation Centre (Aylmer), and the Thames Valley District School Board (Aylmer).

Mitchell Operations Centre:

ETPL's newest operations centre is located in Mitchell, Ontario, a town of approximately 4,500 people. This operations centre as 4 full-time operations staff dedicated to servicing ETPL customers in Mitchell, Dublin, and Clinton. Large electricity users in this region include Cooper-Standard Automotive (Mitchell), Parmalat Canada (Mitchell), and Fleming Feed Mill (Clinton).

1.3.2 Distributors (Host/Embedded)

ETPL has Hydro One as an Embedded Distributor within its service area at four locations. ETPL charges Hydro One the Embedded Distributor rates for these four embedded points.

1.3.3 Distribution Assets

ETPL does not have any transmission or high voltage assets (>50kV) deemed by the Board as distribution assets.

APPLICATION SUMMARY

1.5.1 Revenue Requirement

ETPL has prepared the following table to display the change in revenue requirement requested within its Cost of Service Application.

Detail of Sevice Revenue Requirment	2012 Baord Approved	2018 Proposed Test Year	Variance	%Change
OM&A Expenses	$ 5,660,594	$ 6,468,593	$ 807,999	14%
Amortization Expense	$ 2,030,082	$ 1,842,780	-$ 187,302	-9%
Income Taxes (grossed up)	$ 331,121	$ 190,777	-$ 140,344	-42%
Deemed Interest Expense	$ 803,302	$ 867,816	$ 64,514	8%
Return on Equity	$ 1,147,934	$ 1,415,197	$ 267,263	23%
Service Revenue Requirement	**$ 9,973,033**	**$ 10,785,163**	**$ 812,130**	**8%**

ETPL's proposed Service Revenue Requirement for its 2018 Test Year of $10,785,163 reflects an increase of $812,130 or 8% higher than its 2012 Board Approved amount. The increase is primarily due to an increase in operating costs of $800,000 which is detailed in Exhibit 4 of this application. Amortization has decreased by $187,000 since 2012 and due specifically to the migration to IFRS compliant useful lives. Income taxes have decreased by $140,000 due to a change in approach for the expense of some capital items for tax purposes which is in keeping with ETPL's actual tax returns in the past few years. The deemed interest expense and return on equity have increased by $330,000 since 2012 and has been detailed in Exhibit 2, 3 and 5.

1.5.2 Budgeting and Accounting Assumptions

Capital Budgeting Process:

ETPL's Asset Management practices were formalized in 2011 when it engaged METSCO Energy Solutions to develop an Asset Condition Assessment (ACA) and Asset Management Plan (AMP - included in DSP Appendix H) which was included in the 2012 Cost of Service Rate Application (EB-2012-0121). This formed the basis for more effective Asset Management moving forward and has since been updated with the 2015 AMP (included in DSP Appendix I). It was created to provide an overview of the assets managed by ETPL and outlines the purpose, strategy, objectives and expenditures required to provide safe, reliable and cost effective hydro to our customers.

Prior to formalizing the Asset Management Process in 2011, ETPL had been following good utility practices by replacing assets that had or would be reaching end of life, or otherwise identified as potential failure risks during inspection or testing. The engagement of a third party to formalize the process revealed that ETPL had been potentially under-investing in asset replacement although this had not resulted in sub-standard performance (reliability) of the distribution system.

OM&A Budgeting Process:

ETPL begins to prepare its annual budget plan and five year projections in the third quarter of the year for the coming years. It receives final approval from its Board of Directors in November. However, the budgetary portion of the ETPL 2018 Business Plan was completed in the summer of 2016 in support of this Application. Developing the budget is a key process as it identifies past successes, future initiatives and establishes projections for improving and maintaining capital and on-going operational costs. Every September the Executive team meet to discuss core business objectives, strengths and the future direction of the company. The Executive team look at what is taking place in today's social and economic environments in additional what is anticipated to be coming in the future. With these concepts in mind, they work towards a plan to make ETPL not only a local but a regional example of what an efficient and innovated utility looks like. From here the budget and projections are created. Care is taken to not only ensure that the capital and operating budgets support ETPL's core business objectives but that ETPL is being prudent, financially sustainable and considerate of potential rate impacts to its current and future customers.

ETPL employs the following process with respect to its budgeting process:

1. The Management Team works collectively to look at high level risks and goals including changes in revenue, changes in the economic environment, strategic initiatives from both within ETPL and the industry, cost efficiencies and performance matters that must be considered by each department. This step sets high level expectations for each department on continual cost control and efficiency improvements. Senior management is always mindful of the costs of supplying services verses the rate impact to ETPL's customers.
2. Each department manager or supervisor then develops capital and operating plans keeping these strategic issues or objectives in mind. The following directives are provided to each manager and supervisor to assist them with preparation:
   - External expenses for all department budgets are built using previous year actual, current year forecast and current year budget as a starting platform. From there each third party expense is reviewed to determine whether the service is required, whether there are opportunities for cost minimization or if a service level improvement is required. When able, quotes are obtained to guarantee or confirm future costing;
   - Significant variances in spending from prior years must be explained and documented;
   - A review is done on each departments headcount based on required staffing levels and any need for change;
   - Each department works with Finance to prepare a labour budget using projected wage and benefit costs. These costs are in part predetermined based on union negotiated rates. Overtime is based on projected need and historical comparisons with an expectation that it is closely managed to reduce costs where possible. Salaries, overtime and payroll burden are distributed over accounts based on historical and forecasted allocations;
   - Vehicle costs are forecasted and an hourly rate is determined based on the estimated run time per truck, per working day in the fiscal year. Costs are then distributed over operations, recoverable and capital based on total labour hours budgeted;

- Overhead rates are calculated for the Stores department and applied to the applicable departments in both operating and capital. Overhead rates for Stores are based on material issued, items purchased and contracted services for each functional area.

3. The Finance department then completes an initial consolidation of all departments to develop a draft budget. Finance works with each department to identify variances and issues for consideration.
4. Senior management reviews the draft budget and makes changes and suggestions to balance cost control while still achieving core objectives. In an effort to contain costs, explore efficiencies and still provide an acceptable level of reliability and customer service, the team looks in detail for discretionary costs to identify cost areas that can be delayed or addressed with alternative approaches. These suggestions and changes are then communicated back to the various departments to work into their budgets. At this point steps two to four are repeated. This process results in OM&A costs with a high degree of assurance that ETPL will be able to continue to serve its customers in a safe and reliable manner.
5. Senior management makes a submission to the Board of Directors on the proposed budget and formal approval is requested.

1.5.3 Load Forecast Summary

ETPL engaged Elenchus Research Associates Inc. to provide a Weather Normalized Distribution System Load Forecast for this Application. The full report can be found in Exhibit 3-Attachment 3-A.

To prepare this report, Elenchus considered historic weather data and economic factors using Statistics Canada's employment data for the region. Employment was found not to have a statistically significant explanatory value for the Residential rate class, but was used for the GS < 50 rate class. In addition, a time trend variable, number of days and number of working days in each month, number of customers, and month of year variables have been examined for all rate classes. For forecast values, the average kW to kWh ratio for 2007-2016 was applied for all metered rate classes. For the Street Light and Sentinel rate classes, a more recent history of 2014-2016 was used as these classes should not be sensitive to weather and aren't expected to benefit from the longer time horizon. Specific data and methodology for each rate class can be found in the attached report.

According to the report, the 2018 Weather Normal Forecast total load for ETPL is 468,822,112 kWh and when adjusted for CDM, the total load is 459,842,183 kWh. The number of customer connections is forecasted to be 25,739 for 2018. By comparison, in 2012 ETPL's actual load was 495,162,219 kWh with a total number of customer connections of 23,059. This represents a percentage change of -7.68% in load and a 10.41% change in customer connections.

1.5.4 Rate Base and DSP

ETPL is proposing a Rate Base of $40,296,054 as part of its 2018 Cost of Service Application. The following table details the derivation of this amount.

Description	2012 Board Approved	2018 Test	Variance	% Change
Gross Fixed Assets	$ 41,263,081	$ 59,420,431	$ 18,157,350	44%
Accumulated Depreciation	-$ 14,833,530	-$ 23,577,531	-$ 8,744,001	59%
Net Book Value	$ 26,429,551	$ 35,842,900	$ 9,413,348	36%
Average Net Book Value	**$ 26,429,551**	**$ 35,142,814**	**$ 8,713,263**	**33%**
Controllable Expenses	$ 5,660,594	$ 6,468,593	$ 808,000	14%
Cost of Power	$ 33,092,706	$ 62,241,271	$ 29,148,565	88%
Total Working Capital	**$ 38,753,300**	**$ 68,709,864**	**$ 29,956,564**	**77%**
Working Capital Allow. Factor	13.0%	7.5%	-5.5%	-42%
Working Capital Allowance	$ 5,037,929	$ 5,153,240	$ 115,311	2%
Rate Base	**$ 31,467,480**	**$ 40,296,054**	**$ 8,828,574**	**28%**

ETPL is proposing an increase of $8,830,000 or 28% since 2012. The main driver of this change is the increase in net book value of $8,700,000 which is detailed in Exhibit 2 and supported by ETPL's Distribution System Plan as presented as part of this application. The following table details the capital additions by year since 2012.

CATEGORY	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
System Access	758,310	1,420,455	1,316,968	1,060,304	793,628	879,500	920,100	812,700	816,300	759,900
System Renewal	789,397	2,298,252	1,830,486	1,515,632	1,673,992	2,142,450	2,002,230	1,907,040	2,168,882	1,939,454
System Service	42,215	3,856	64,232	188,030	448,318	73,000	74,875	76,750	55,900	55,000
General Plant	572,239	332,164	763,110	486,054	633,975	148,000	234,875	451,750	223,400	526,450
TOTAL EXPENDITURE	2,162,161	4,054,727	3,974,796	3,250,020	3,549,913	3,242,950	3,232,080	3,248,240	3,264,482	3,280,804

ETPL's working capital increased by almost $30,000,000 since 2012 primarily due to the increase in commodity costs derived utilizing current commodity rates and the load forecast submitted as part of this application. The following table details the derivation of the change in ETPL's Working Capital since 2012 Board Approved. These calculation have been further detailed in Exhibit 2. Despite this large increase in working capital it only represents a $115,000 increase in working capital allowance due to the reduction in the allowance factor from 13% to 7.5%.

Description	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Bridge	2018 Test
Accounting Standard	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 186,301	$ 160,299	$ 100,096	$ 110,018	$ 128,569	$ 91,574	$ 93,131	$ 116,389
Miantenance	$ 685,298	$ 595,216	$ 645,161	$ 578,159	$ 320,160	$ 286,802	$ 291,677	$ 298,526
Billing & Collecting	$ 991,287	$ 860,983	$ 1,172,874	$ 1,259,465	$ 1,111,468	$ 981,647	$ 998,335	$ 1,040,307
Community Relations	$ -	$ 18,711	$ 22,086	$ 22,871	$ 21,168	$ 24,584	$ 24,953	$ 25,327
Admin & General	$ 3,728,786	$ 3,219,930	$ 3,660,512	$ 3,632,435	$ 4,210,858	$ 4,607,894	$ 4,718,455	$ 4,918,914
Property Taxes	$ 57,416	$ 49,869	$ 49,018	$ 48,531	$ 64,612	$ 54,540	$ 55,358	$ 56,188
LEAP	$ 11,506	$ 11,506	$ 11,825	$ 11,825	$ 11,825	$ 11,825	$ 11,825	$ 12,942
Total Controllable	$ 5,660,594	$ 4,916,514	$ 5,661,572	$ 5,663,305	$ 5,868,660	$ 6,058,865	$ 6,193,734	$ 6,468,593
Cost of Power	$ 33,092,706	$ 44,886,698	$ 48,381,613	$ 49,839,585	$ 53,987,814	$ 60,034,318	$ 63,391,860	$ 62,241,271
Total Working Capital	$ 38,753,300	$ 49,803,212	$ 54,043,184	$ 55,502,890	$ 59,856,474	$ 66,093,183	$ 69,585,594	$ 68,709,864
Allowance Factor	13%	13%	13%	13%	13%	13%	13%	7.5%
Working Capital Allowance	**$ 5,037,929**	**$ 6,474,418**	**$ 7,025,614**	**$ 7,215,376**	**$ 7,781,342**	**$ 8,592,114**	**$ 9,046,127**	**$ 5,153,240**

1.5.5 OM&A Expense

ETPL is proposing an increase of $807,000 over its 2012 Board Approved OM&A costs, an increase of 14%. The following table details the changes in OM&A by year since 2012. ETPL has demonstrated an ability to minimize its increases to less than inflation since 2012 despite the addition of programs and services it is adding to enhance its customers experience with respect to reliability and automation.

Expenses	Last Rebasing Year (2012 Board Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Operations	$ 187,551	$ 160,299	$ 100,096	$ 110,018	$ 128,569	$ 91,574	$ 93,131	$ 116,389
Maintenance	$ 696,405	$ 595,216	$ 645,161	$ 578,159	$ 320,160	$ 286,802	$ 291,677	$ 296,636
Billing and Collection	$ 987,418	$ 860,983	$ 1,172,874	$ 1,259,465	$ 1,111,468	$ 981,647	$ 998,335	$ 1,040,307
Community Relations	$ -	$ 18,711	$ 22,086	$ 22,871	$ 21,168	$ 24,584	$ 24,953	$ 25,327
Administrative and General	$ 3,789,220	$ 3,281,305	$ 3,721,355	$ 3,692,792	$ 4,287,295	$ 4,674,259	$ 4,785,638	$ 4,989,935
Total	**$ 5,660,594**	**$ 4,916,514**	**$ 5,661,572**	**$ 5,663,305**	**$ 5,868,660**	**$ 6,058,865**	**$ 6,193,734**	**$ 6,468,593**

1.5.6 Cost of Capital

ETPL has not deviated from the Board's Report on Cost of Capital for Ontario's Regulated Utilities issued December 11th, 2009 in its application. ETPL seeks to recover a weighted average cost of capital of 5.67% based upon the deemed debt equity split of 60/40 where 56% of debt is deemed long term at 3.72% and 4% at 1.76% and the equity portion yields 8.78%. The resulting returns are $867,816 on debt and $1,415,197 on equity as detailed in the following table. ETPL is requesting an increase of $331,177 on weighted average cost of capital since its 2012 approved application. Further details can be found in Exhibit 2 and 5.

	Per Board Decision - EB-2012-0121				Per Board Decision - EB-2012-0121					
	Capitalization Ratio				Capitalization Ratio					
Description	**%**	**$**	**Cost Rate %**	**Return $**	**%**	**$**	**Cost Rate %**	**Return $**	**Variance**	**% Change**
Debt										
Long Term Debt	56.00%	$ 17,621,789	4.41%	$ 777,121	56.00%	$ 22,565,790	3.72%	$ 839,447	$ 62,326	8.02%
Short Term Debt	4.00%	$ 1,258,699	2.08%	$ 26,181	4.00%	$ 1,611,842	1.76%	$ 28,368	$ 2,187	8.35%
Total Debt	60.00%	$ 18,880,488	4.25%	$ 803,302	60.00%	$ 24,177,633	3.59%	$ 867,816	$ 64,514	8.03%
Equity										
Common Equity	40.00%	$ 12,586,992	9.1%	$ 1,147,934	40.00%	$ 16,118,422	8.8%	$ 1,415,197	$ 267,263	23.28%
Preferred Shares	0.00%	$ -	0.0%	$ -	0.00%	$ -	0.0%	$ -		
Total Equity	**40.00%**	**$ 12,586,992**	**$ 0**	**$ 1,147,934**	**40.00%**	**$ 16,118,422**	**$ 0**	**$ 1,415,197**	$ 267,263	23.28%
Total	**100.0%**	**$ 31,467,480**	**6.20%**	**$ 1,951,236**	**100.0%**	**$ 40,296,054**	**5.67%**	**$ 2,283,013**	**$ 331,777**	**17.00%**

1.5.7 Cost Allocation & Rate Design

ETPL has filed its cost allocation filing and rate design consistent with its understanding of The Board's Direction and Guidelines issued in November of 2006 and updated annually. ETPL has utilized the most recent Cost Allocation model posted on the OEB website in July of 2017. ETPL has updated its historical load data that underpins the cost allocation methodology. Historically ETPL utilized the 2004 weather normalized load data as prepared by Hydro One, in order to obtain more recent data ETPL utilized the services of Elenchus to modernize this data; details of this process has been provided in Exhibit 8 of this application. The following table details the changes in revenue to cost ratios. Details on the process to adjust and arrive at the applied for R/C ratios can be found in Exhibit 8 of the application.

Name of Customer Class	Previously Approved Ratios Most Recent Year: 2012 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
Residential	62.03%	86.35%	94.60%	85 - 115
General Service < 50 kW	12.57%	100.35%	118.61%	80 - 120
General Service > 50 to 999 kW	9.49%	168.54%	106.53%	80 - 120
General Service > 1,000 to 4,999 kW	5.79%	165.84%	115.24%	80 - 120
Large Use	3.38%	81.28%	105.02%	85 - 115
Unmetered Scattered Load	0.78%	177.11%	115.00%	80 - 120
Sentinel Lighting	0.33%	53.10%	111.68%	80 - 120
Street Lighting	3.79%	188.86%	106.22%	80 - 120
Embedded Distributor	1.83%	252.87%	104.92%	80 - 120

In 2015 the OEB implemented a phase in of a migration to fully fixed distribution rates for residential customers. ETPL has complied with this change and has incorporated the next progression in its application. For all other classes distribution revenue is derived from fixed and variable revenues and the calculation of rates followed the previous percentage split between the two. However for both the Large Use and GS>1,000 to 4,999 kW classes the current fixed charge were in excess of the maximum fixed charge as calculated in the cost allocation model. For these two groups ETPL has proposed that the fixed charge remain the same and that the remaining distribution revenue be recovered on a variable basis. The following table details the fixed and variable charges currently in place vs. the fixed and variable rates proposed in this application.

Customer Class	Allocator	2017 Existing Fixed Rates	2017 Existing Variable Rates	2018 Proposed Fixed Rates	2018 Proposed Variable Charge
Residential	kWh	$ 23.22	$ 0.0094	$ 29.37	$ 0.0053
General Service < 50 kW	kWh	$ 22.29	$ 0.0145	$ 26.95	$ 0.0175
General Service > 50 to 999 kW	kW	$ 127.91	$ 3.1024	$ 82.28	$ 2.0674
General Service > 1,000 to 4,999 kW	kW	$ 2,537.23	$ 4.2161	$ 2,537.23	$ 2.5270
Large Use	kW	$ 10,362.66	$ 1.9046	$ 10,362.66	$ 2.5716
Unmetered Scattered Load	kWh	$ 3.20	$ 0.1142	$ 2.10	$ 0.0749
Sentinel Lighting	kWh	$ 4.04	$ 23.5048	$ 12.31	$ 0.0893
Street Lighting	kW	$ 5.59	$ 15.6727	$ 2.25	$ 13.1162
Embedded Distributor	kW	$ 2,361.50	$ 4.0623	$ 978.34	$ 1.6829

1.5.8 Deferral and Variance Accounts

As outlined in Exhibit 9, ETPL is requesting approval for disposition of Group 1, Group 2 and Other Deferral and Variance Accounts in the amount of $1,228,127 owing from customers. This includes an RSVA-Global Adjustment amount of $1,031,918 being owed to ETPL by Non-RPP Customers only and an amount of $101,708 for CBR being owed to ETPL from Class B customers only. The remaining disposition of $94,502 is owed from all customers. The following table details the amount of regulatory assets and liabilities proposed for disposal in this application. Detailed explanations of these amounts and proposed disposition methodologies can be found in Exhibit 9.

Line No.	USoA	Description	Balance for Disposition
	GROUP ONE		
1	1550	Low Voltage	$ 1,374,397
2	1551	Smart Metering Entity Charge	-$ 11,557
3	1580	RSVA Wholesale Market	-$ 1,526,138
4	1580	WMS -Sub-account CBR Class B	$ 101,708
5	1584	RSVA Network	$ 56,324
6	1586	RSVA Connection	$ 243,195
7	1588	RSVA Power	$ 318,226
8	1589	RSVA Global	$ 1,031,919
9	1595	Disposition and Recovery of Regulatory Assets-2012	-$ 602,884
10	1595	Disposition and Recovery of Regulatory Assets-2014	$ 640,410
11	1595	Disposition and Recovery of Regulatory Assets-2015	-$ 52,680
12		**Subtotal**	$ 1,572,920
13	**GROUP TWO**		
14	1508	Other Regulatory Assets-OEB Cost Assessemnt	$ 309,431
	1508	Other Regulatory Assets-OEB Cost Assessemnt	$ 29,993
15		**Subtotal**	$ 339,424
16	1568	LRAM Variance Account	$ 364,609
17	1576	Accounting Changes Under CGAAP Balance + Return Component5	-$ 1,048,825
18		**GRAND TOTAL**	$ 1,228,127

1.5.9 Bill Impacts

ETPL has calculated bill impacts utilizing the model provided by The Board and has provided a summary of those impacts in the table below. ETPL has determined that no customers (including customers at the lowest 10th percentile) are impacted materially as a result of this application and as such no mitigation plan is required.

Rate Class	Billing Determinant	2017 Bill Amount	Proposed 2018 Bill Amount	Difference	Total Bill Impact
Residential RPP	233	$ 53.33	$ 57.23	$ 3.90	7.31%
Residential Non-RPP	233	$ 62.02	$ 65.62	$ 3.60	5.80%
Residential Non-RPP	800	$ 151.61	$ 150.76	-$ 0.85	-0.56%
Residential RPP	1000	$ 145.04	$ 143.89	-$ 1.15	-0.79%
Residential RPP	500	$ 85.26	$ 87.40	$ 2.14	2.51%
Residential RPP	750	$ 115.15	$ 115.64	$ 0.49	0.43%
GS<50 kw RPP	2000	$ 287.08	$ 290.80	$ 3.72	1.30%
GS<50 kw RPP	1000	$ 155.79	$ 160.09	$ 4.30	2.76%
GS<50 kw RPP	5000	$ 680.97	$ 682.91	$ 1.94	0.28%

CUSTOMER ENGAGEMENT

Customer engagement and communication is necessary to ensure ETPL is providing the level of service expected by its customers. The following outlines the strategies utilized by ETPL to better engage its customers.

1.6.1 Customer Engagement Overview

ETPL engages with customers on a regular basis through a variety of channels, including but not limited to:

- Continuous website enhancements
- News stories shared online
- eCare – the customer web portal
- Online payment notification
- Scheduled outage notifications by phone, hand delivered notices and/or personal knock at the door, websites, social media
- Unexpected outage notifications by website and social media during business hours and major events
- Regular bill inserts
- Conservation and safety information and updates online
- Involvement in and sponsorship of local events (i.e. the Fusion Youth Centre's Run Ingersoll fundraiser)
- Low-income support (i.e. LEAP program)
- Radio advertisements
- Print advertisements
- Electricity school education program
- Customer satisfaction surveys
- Employee fundraising for local charities
- Town hall meetings

ETPL's customer service department is usually the first and most common means of access to the company. In 2016, approximately 30,125 calls were received by the customer service staff. There are a variety of reasons customers call including questions about their accounts, bills, and components, activating new accounts, and reporting and/or inquiring about outages. The customer service department makes several outbound calls on a variety of issues including calls to customers and calls to co-ordinate service arrangements with operations personnel. Many customers are also contacted by phone to be informed about operational activity occurring in their area including maintenance.

ETPL also offers eCare, an online portal for customers to log into to view their bill and historical data. Currently ETPL has 18% of its customers enrolled in eCare. ECare is another tool used by ETPL to communicate with customers about anything that could affect their bill or service. Using eCare reduces the amount of inbound calls for easily accessible information making customer service staff available to help with more complicated issues.

In early 2017, ETPL hosted three Town Hall meetings (one in each service region), to provide customers an opportunity to meet senior management and ask questions about various aspects of the business. ETPL staff gave a presentation with regards to our upcoming Cost of Service Application, to help customers better understand our rate application process and the expected minimal impact. As well as a better understanding of the industry, the customer's bills, and their options including conservation and programs to help offset electricity costs.

To better understand customers' expectations of ETPL, a customer survey was issued in 2014 and 2016. The surveys can be found in Attachments 1-F and 1-G in this Exhibit. The goal of these surveys was to help ETPL in planning future activities such as communication channels and investment opportunities. The latest survey showed ETPL customers were 89% satisfied with ETPL's performance on a variety of measures. In particular, customers indicated that improvements could be made to better communicate planned outages as well as education about payment options and a general understanding of their bills.

In the time since the survey, ETPL has focused on improving this communication using a variety of tools including the aforementioned town halls, as well as bill inserts, an increased social media presence, website articles and a more user friendly website. Ahead of scheduled outages, information is communicated on the website and social media and automated voice calls are made to all customers affected by the outage. In addition, senior operations and IT staff have been provided access to the @ETPLOutages Twitter account to inform customers during unexpected outages. When a tweet is posted to that account, it is set up to automatically post to Facebook and the ETPL website as well. The feedback has been generally positive since implementing these communication methods and procedures.

Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Residential & Small Business Customer Surveys	- Cost of Electricity; reliability of electricity	ETPL is maintaining a relatively flat level of capital spending aim at maintaining the existing level of reliability.
Large Customer/Group Consultations	Reliability, Power Quality	ETPL has met with directly with its 5 largest customers on an individual basis to understand their needs and concerns with respect to the supply and delivery of electricity to their business. ETPL has worked diligently over the years to improve power quality, reliability and in some cases redundancy to ensure the customer's needs are met.
Municipal Planning Committee	Municipal driven projects being planned- work with all 9 municipalites in which ETPL operates	ETPL manages its customer spend and coordinates its activities with respect to planned work being performed to ensure lack of duplicate effort and makes every effort to renew distribution assets where road widening and or sewer replacements are scheduled.
Website	- access to current usage and cost dat - conservation information - contact information in case of emergency, bill payment issues and general questions - links to related sites	ETPL's website provides a substantial amount of information to our customer, with relation to their utility bills, services available to customer, rates and how bills are calculated, scheduled power outages, conservation, generation, and electrical safety. We also help to promote community events, and general industry information, as well as our RRFE scorecard.
Bill inserts and Bill notes	- current programs available to save energy - conservation programs and coupons available	ETPL takes advantage of our ability to provide information to our customers both through the use of bill inserts and bill notes
Electrical Safety and Community Events	- general safety guidelines for homeowners and contractors - educational information for primary school children - seasonal saftety reminders	For several years ETPL has been providing a yearly Electrical Safety program to the Elementary School students within our own territory. We have a service provider go into the class room and demonstrate electrical risks and safety actions to be taken. We have always had a great response from the schools within our service territory, and attempt to cycle through all the schools at least once every four years. We also attend various community events such as The Future Oxford Expo where we provide safety tips, and conservation program information.
Conservation and Demand Management	- reduction of consumption of electricity	Our Conservation and Demand Management team is quite active in engaging our customers on a regular basis. We are in regular contact with our largest user (GM-CAMI Automotive) working together to find ways to conserve and review new technical opportunities that would improve their operations. We also hold topic specific meeting, such as our Compressed Air Efficiencies and Incentives Seminar held in May 2015. Commercial/Industrial customers that use compressed air were invited to attend a meeting which we hosted to discuss how to make compressed air systems more efficient and the incentives available from the save on energy program.
Customer Surveys	- decrease cost of electricity - sustain reliability of electricity - sustain quality of electricity	ETPL has completed customer surveys in both 2014 & 2016 and will continue this trend moving forward to obtain valuable information regarding customer satisfaction, knowledge and preferences surrounding their electricity supply. Each additional survey will allow ETPL to trend customer satisfaction and make adjustments to its distribution system plan if warranted. A complete report detailing the results of each customer survey is included in Appendix A & B. ETPL began surveying customers on a yearly basis in 2014. The premise of our first survey was to identify our customers' preferences regarding the existing level of service reliability and costs, and was targeted at our residential and small business classes. The 2016 survey was again used to collect data from customers regarding their satisfaction, knowledge and preferences however in addition was used to provide customers with a better understanding of where ETPL fits within the provincial electricity system and found that the majority of customers do not have a great understanding of the system and what Erie Thames controls and does not control. ETPL had 1136 customers respond to the customer survey in 2016 as compared to 897 in the 2014 customer survey. The 2014 survey did not use email as a medium and found that the number of responses jumped substantially when customers were contacted via email in 2016. The surveys as a whole shows our customers are satisfied with the level of service which they receive from ETPL and feel that we are managing costs effectively. Both surveys reflect that customers are most concerned with total price and reliability, with the majority of respondents indicating that they find the existing level of reliability to be acceptable. These results are reflected in the DSP with a relatively flat level of capital spending aimed at maintaining the existing level of reliability.

Community Involvement	-electrical safety education - electrical conservation -	ETPL attends various community events to promote electrical safety and energy saving initiatives. ETPL presence at community events provides an informal forum for customers to speak with various levels of staff and discuss any concerns they may have.
Communications through Call Center, and emails to general information email	- account information, ie- balance owing - service requests - outage details	Various customer inquiries, complaints and other concerns are documented and assigned to engineering, operations or customer service staff for remediation. Typically communications are related to very specific issues that are addressed immediately if possible.
Communications directly through Engineering and Operations Department	- new service requests - maintenance requests - new developments (ie subdivision, municial infrastructure)	The majority of contact directly through engineering and operations revolves around new service or service upgrade requests. These are typically forwarded to the Call Center to ensure that a proper service order is created for tracking purposes. Any customer concerns are generally addressed immediately or documented for input into capital plans as required. Prior to starting a project that may directly impact customers, written notices are given to customers identifying the scope of the project, potential impact to them (short outages to transfer services, excavations in front of their property, traffic flow changes, etc.), and contact information if they have questions or concerns.
Social Media	- general information - conservation information - outage details - industry news	ETPL Facebook and Twitter accounts are monitored to obtain general feedback from customers.
Meetings and Information Sessions		Engineering and Operations staff meets with various customers throughout a given year for various reasons including, customers' requests, effects of ETPL capital projects, or yearly planned meetings.
CDM Activities		CDM staff regularly initiates contact with medium to large commercial and industrial customers to discuss various initiatives through face-to-face meetings and information sessions. Discussion surrounding distribution related concerns are welcomed and communicated with engineering and operations staff.
Corporate Board of Directors		At a corporate level the Board of Directors are local municipal government officials who are able to provide feedback received from constituents regarding distribution related concerns.

1.6.2 Informing Customers

ETPL contacted all customers via automated telephone calls, notifying them of our Town Hall Meetings being held and were invited to attend and be involved.

1.6.3 Other Customer Communication

Website /Social Media

ETPL's website provides a substantial amount of information to our customer, with relation to their utility bills, services available to customer, rates and how bills are calculated, scheduled power outages, conservation, generation, and electrical safety. We also help to promote community events, and general industry information, as well as our RRFE scorecard. ETPL has an active Facebook and Twitter accounts that are used to keep customers informed of outages (planned or otherwise), Conservation and Demand Management programs, safety awareness tips, and regulatory notifications.

Bill inserts and Bill notes

ETPL takes advantage of our ability to provide information to our customers both through the use of bill inserts and bill messages.

Electrical Safety and Community Events

For several years ETPL has been providing a yearly Electrical Safety program to the Elementary School students within our own territory. We have a service provider go into the class room and demonstrate electrical risks and safety actions to be taken. We have always had a great response from the schools within our service territory, and attempt to cycle through all the schools at least once every four years. We also attend various community events such as The Future Oxford Expo where we provide safety tips, information about ETPL's distribution system, rates and conservation programs.

Conservation and Demand Management

Our Conservation and Demand Management team is quite active in engaging our customers on a regular basis. We are in regular contact with our largest users working together to find ways to conserve and review new technical opportunities that would improve their operations. We also hold topic specific meeting, such as our Compressed Air Efficiencies and Incentives Seminar held in May 2015. Commercial/Industrial customers that use compressed air were invited to attend a meeting which we hosted to discuss how to make compressed air systems more efficient and the incentives available from the save on energy program. These conservation customer engagement activities have also helped to inform decisions made by ETPL during the execution phase of some of its capital projects.

Frequently customers contact ETPL to express a concern about or have a question about the proposed or recently completed project in their area. These concerns and questions are forwarded to the engineering and operations department who will review these with the customer and may adjust the schedule or scope of the project to meet the customers' preferences, provided they do not adversely affect the overall project cost and schedule. These interactions are also reviewed by management as a quality control measure, to ensure the ETPL employees and contractors are doing the work effectively and providing the expected level of customer service.

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Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Residential & Small Business Customer Surveys	- Cost of Electricity; reliability of electricity	ETPL is maintaining a relatively flat level of capital spending aim at maintaining the existing level of reliability.
Large Customer/Group Consultations	Reliability, Power Quality	ETPL has met with directly with its 5 largest customers on an individual basis to understand their needs and concerns with respect to the supply and delivery of electricity to their business. ETPL has worked diligently over the years to improve power quality, reliability and in some cases redundancy to ensure the customer's needs are met.
Municipal Planning Committee	Municipal driven projects being planned- work with all 9 municipalites in which ETPL operates	ETPL manages its customer spend and coordinates its activities with respect to planned work being performed to ensure lack of duplicate effort and makes every effort to renew distribution assets where road widening and or sewer replacements are scheduled.
Website	- access to current usage and cost dat - conservation information - contact information in case of emergency, bill payment issues and general questions - links to related sites	ETPL's website provides a substantial amount of information to our customer, with relation to their utility bills, services available to customer, rates and how bills are calculated, scheduled power outages, conservation, generation, and electrical safety. We also help to promote community events, and general industry information, as well as our RRFE scorecard.
Bill inserts and Bill notes	- current programs available to save energy - conservation programs and coupons available	ETPL takes advantage of our ability to provide information to our customers both through the use of bill inserts and bill notes
Electrical Safety and Community Events	- general safety guidelines for homeowners and contractors - educational information for primary school children - seasonal saftety reminders	For several years ETPL has been providing a yearly Electrical Safety program to the Elementary School students within our own territory. We have a service provider go into the class room and demonstrate electrical risks and safety actions to be taken. We have always had a great response from the schools within our service territory, and attempt to cycle through all the schools at least once every four years. We also attend various community events such as The Future Oxford Expo where we provide safety tips, and conservation program information.
Conservation and Demand Management	- reduction of consumption of electricity	Our Conservation and Demand Management team is quite active in engaging our customers on a regular basis. We are in regular contact with our largest user (GM-CAMI Automotive) working together to find ways to conserve and review new technical opportunities that would improve their operations. We also hold topic specific meeting, such as our Compressed Air Efficiencies and Incentives Seminar held in May 2015. Commercial/Industrial customers that use compressed air were invited to attend a meeting which we hosted to discuss how to make compressed air systems more efficient and the incentives available from the save on energy program.
Customer Surveys	- decrease cost of electricity - sustain reliability of electricity - sustain quality of electricity	ETPL has completed customer surveys in both 2014 & 2016 and will continue this trend moving forward to obtain valuable information regarding customer satisfaction, knowledge and preferences surrounding their electricity supply. Each additional survey will allow ETPL to trend customer satisfaction and make adjustments to its distribution system plan if warranted. A complete report detailing the results of each customer survey is included in Appendix A & B. ETPL began surveying customers on a yearly basis in 2014. The premise of our first survey was to identify our customers' preferences regarding the existing level of service reliability and costs, and was targeted at our residential and small business classes. The 2016 survey was again used to collect data from customers regarding their satisfaction, knowledge and preferences however in addition was used to provide customers with a better understanding of where ETPL fits within the provincial electricity system and found that the majority of customers do not have a great understanding of the system and what Erie Thames controls and does not control. ETPL had 1136 customers respond to the customer survey in 2016 as compared to 897 in the 2014 customer survey. The 2014 survey did not use email as a medium and found that the number of responses jumped substantially when customers were contacted via email in 2016. The surveys as a whole shows our customers are satisfied with the level of service which they receive from ETPL and feel that we are managing costs effectively. Both surveys reflect that customers are most concerned with total price and reliability, with the majority of respondents indicating that they find the existing level of reliability to be acceptable. These results are reflected in the DSP with a relatively flat level of capital spending aimed at maintaining the existing level of reliability.
Community Involvement	-electrical safety education - electrical conservation -	ETPL attends various community events to promote electrical safety and energy saving initiatives. ETPL presence at community events provides an informal forum for customers to speak with various levels of staff and discuss any concerns they may have.
Communications through Call Center, and emails to general information email	- account information, ie- balance owing - service requests - outage details	Various customer inquiries, complaints and other concerns are documented and assigned to engineering, operations or customer service staff for remediation. Typically communications are related to very specific issues that are addressed immediately if possible.
Communications directly through Engineering and Operations Department	- new service requests - maintenance requests	The majority of contact directly through engineering and operations revolve around new service or service upgrade

1.5.2 INFORMING CUSTOMERS

ETPL contacted all customers via automated telephone calls, notifying them of our Town Hall Meetings being held and were invited to attend and be involved.

1.5.3 OTHER CUSTOMER COMMUNICATION

Website /Social Media

ETPL's website provides a substantial amount of information to our customer, with relation to their utility bills, services available to customer, rates and how bills are calculated, scheduled power outages, conservation, generation, and electrical safety. We also help to promote community events, and general industry information, as well as our RRFE scorecard. ETPL has an active Facebook and Twitter accounts that are used to keep customers informed of outages (planned or otherwise), Conservation and Demand Management programs, safety awareness tips, and regulatory notifications.

Bill inserts and Bill notes

ETPL takes advantage of our ability to provide information to our customers both through the use of bill inserts and bill messages.

Electrical Safety and Community Events

For several years ETPL has been providing a yearly Electrical Safety program to the Elementary School students within our own territory. We have a service provider go into the class room and demonstrate electrical risks and safety actions to be taken. We have always had a great response from the schools within our service territory, and attempt to cycle through all the schools at least once every four years. We also attend various community events such as The Future Oxford Expo where we provide safety tips, information about ETPL's distribution system, rates and conservation programs.

Conservation and Demand Management

Our Conservation and Demand Management team is quite active in engaging our customers on a regular basis. We are in regular contact with our largest users working together to find ways to conserve and review new technical opportunities that would improve their operations. We also hold topic specific meeting, such as our Compressed Air Efficiencies and Incentives Seminar held in May 2015. Commercial/Industrial customers that use compressed air were invited to attend a meeting which we hosted to discuss how to make compressed air systems more efficient and the incentives available from the save on energy program. These conservation customer engagement activities have also helped to inform decisions made by ETPL during the execution phase of some of its capital projects.

Frequently customers contact ETPL to express a concern about or have a question about the proposed or recently completed project in their area. These concerns and questions are forwarded to the engineering and operations department who will review these with the customer and may adjust the schedule or scope of the project to meet the customers' preferences, provided they do not adversely affect the overall project cost and schedule. These interactions are also reviewed by management as a quality control measure, to ensure the ETPL employees and contractors are doing the work effectively and providing the expected level of customer service.

PERFORMANCE MEASUREMENT

Erie Thames Powerlines Corporation takes great pride in its OEB Scorecard results each year and strives for continuous improvement.

1.7.1 Scorecard Performance

According to the 2015 Scorecard issued by the OEB, ETPL has met and exceeded industry targets in nearly every category. The only category in which ETPL did not meet the industry target was with respect to reliability and the average number of times that power to a customer is interrupted. Bad weather and increasing failure rates for aging distribution assets combined led to this slight decreasing in reliability measures for 2015. However, ETPL remains well under the former mandated targets and continues to provide excellent reliability for its customers, which is significantly better than the industry average.

ETPL monitors its scorecard results and is continually seeking to improve upon its performance in order to improve the service provided to its customers.

Below is a discussion on each of the scorecard's measures. ETPL's full 2015 scorecard can be found in Appendix 1-H of this exhibit. Also included in Attachment 1-G is ETPL's 2016 Draft Scorecard.

1.7.2 Customer Focus

Measure: Service Quality - New Residential/Small Business Services Connected on Time:

2011	2012	2013	2014	2015	Target
99.30%	98.80%	98.80%	99.40%	98.40%	90.00%

In 2015, ETPL connected 189 new residential and small businesses to the distribution system. This is a relatively small number, which helps ETPL continue its solid performance in this area. Due to the relatively small number of new connections, it is expected that the current level of performance will be easily maintained until such a time that there is a significant increase in the number of new connections required.

Measure: Service Quality – Scheduled Appointments Met On Time:

2011	2012	2013	2014	2015	Target
98.10%	100.00%	100.00%	100.00%	100.00%	90.00%

ETPL scheduled 12 appointments with its customers in 2015 to complete work requested by customers. Consistent with prior years, ETPL met 100% of these appointments, which significantly exceeds the industry target of 90%. With a relatively low number of scheduled appointments requested by customers, it is expected that ETPL will continue to maintain its perfect record in meeting these appointments on time. In 2016 ETPL scheduled 268 appointments in which all were met on time as well. The increase in the number of scheduled appointments was due to a change in the way scheduled appointments were tracked with respect to this measure.

Measure: Service Quality - Telephone Calls Answered On Time:

2011	2012	2013	2014	2015	Target
99.30%	98.80%	98.80%	99.40%	98.40%	90.00%

ETPL's customer service staff received approximately 27,545 calls in 2015 and answered 98.4% of those calls within 30 seconds. This significantly exceeds the OEB's required level of service and is consistent with ETPL's previous performance. ETPL will strive to continue its excellent call centre performance in future years and strive to reduce the number of abandoned calls experienced by our customers.

Measure: Customer Satisfaction - First Contact Resolution:

2011	2012	2013	2014	2015	Target
n/a	n/a	n/a	99.70%	99.85%	n/a

The OEB has not yet implemented a commonly defined measure for this area, but plans to review information provided by electricity distributors over the next few years to help create the standard. ETPL measures First Contact Resolution based on actual calls received customers with respect to the same or similar issues and calculated this number as a percentage of all customer contacts received that resulted in the generation of an issue for which a service order was created. Using this calculation, ETPL dealt with 99.8% of customers' issues on first contact. ETPL will continue to review its tracking of this measure and will adjust how the data is compiled. It is expected that the 2016 result will decrease due to more effective tracking of this measure.

Measure: Customer Satisfaction - Billing Accuracy:

2011	2012	2013	2014	2015	Target
n/a	n/a	n/a	99.85%	99.46%	98.00%

The OEB prescribed a measurement of billing accuracy to be used by all electricity distributors effective October 1, 2015. For 2015, ETPL issued 224,578 bills and achieved a billing accuracy of 99.46%, which exceeds the OEB's target of 98%. ETPL will continue to monitor its billing accuracy results and processes to identify opportunities for improvement.

Measure: Customer Satisfaction - Customer Satisfaction Survey Results:

2011	2012	2013	2014	2015	Target
n/a	n/a	n/a	100.00%	89.00%	n/a

ETPL undertook its first customer satisfaction survey in 2015. The results determined that its customers were 89% satisfied with ETPL's performance on a variety of measures. Customers indicated that improvements can be made to better communicate planned outages. In addition, customers indicated ETPL can make improvements with respect to billing, with educating our customers about payment options available, with the delivery of bills, and a general understanding of their bills. Some customers indicated the ETPL website needed to be updated, however it is not clear if they visited the newly launched website that went live shortly before the survey was issued.

ETPL takes customer feedback very seriously. The results of this survey have helped shaped policies and procedures to help improve the customer's experience. The survey will be issued bi-annually to further track customer satisfaction.

1.7.3 Operational Effectiveness

Measure: Safety – Level of Public Awareness:

2011	2012	2013	2014	2015	Target
n/a	n/a	n/a	n/a	83.40%	n/a

In 2015, ETPL completed a customer survey to gauge public awareness of Electrical Safety. A third party agency was utilized to survey ETPL's customers and to ensure that an accurate sampling was achieved. The survey's results showed that 83.4% of ETPL customers have strong awareness of electrical safety. ETPL will continue to work within its communities to ensure that this metric continues to improve in the future. The customer survey to gauge public safety awareness will be completed bi-annually.

Measure: Safety – Level of Compliance with Ontario Regulation 22/04:

2011	2012	2013	2014	2015	Target
NI	C	NI	C	C	C

Ontario Regulation 22/04 – *Electrical Distribution Safety* establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, specifications, and inspection of construction before they are put into service.

In 2014 and 2015, ETPL was found to be compliant with Ontario Regulation 22/04. In 2013, ETPL was given a score of Needs Improvement. This score was given due to an interpretation issue with respect to the ESA requirement to ground utilizing a metal guard. The ESA resolved with ETPL that the grounding was not required with the specifications used by ETPL but the resolution was not obtained until after the 2013 results were published.

Measure: Safety – Serious Electrical Incident Index – Number of General Public Incidents:

2011	2012	2013	2014	2015	Target
0	0	0	0	0	0

ETPL has no reported serious incidents from 2010 to 2015. ETPL continues to be committed to safety in an effort to ensure this trend continues.

Measure: Safety – Serious Electrical Incident Index – Rate per 10, 100, 1000 km of line:

2011	2012	2013	2014	2015	Target
0.000	0.000	0.000	0.000	0.000	0.000

ETPL has no reported serious incidents from 2010 to 2015. ETPL continues to be committed to safety in an effort to ensure this trend continues.

Measure: System Reliability – Average Number of Hours that Power to a Customer is Interrupted:

2011	2012	2013	2014	2015	Target
1.53	1.47	0.41	0.59	0.73	0.99

ETPL had a slight increase in the number of hours that power to a customer was interrupted in 2015. The total number of outages hours is still on the low side of the former target range provided by the OEB. ETPL's results fell within the new LDC specific requirement of 0.99 for SAIDI, however there has been an increase over the past two years that needs to be managed to ensure the trending is not a systemic issue within ETPL's distribution system as opposed to a significant one time anomalous events.

ETPL views reliability of electricity service as a high priority for its customers and as such conducts a vegetation management program that ensures the whole system is trimmed every three years. Similarly, ETPL is dedicated to upgrading its assets to 27.6 kV in order to reduce its reliance on substations and thereby ensure that its reliability continues to be above average as aging stations are retired. This, combined with the ETPL senior management team's commitment to review the worst performing feeders on a quarterly basis in order to potentially improve reliability, will ensure customers continue to receive excellent reliability from ETPL's system.

Measure: System Reliability – Average Number of Times that Power to a Customer Is Interrupted:

2011	2012	2013	2014	2015	Target
0.75	0.31	0.20	0.30	0.48	0.41

ETPL's average number of times that power to a customer was interrupted increased slightly for 2015, but is still at the low end of the former range of acceptable results set by the OEB. However, when compared to the new distributor specific target of 0.41, ETPL was marginally above the target and therefore is showing that this target was not met. While the result is portrayed as a target that is not met, the results that ETPL has achieved with respect to SAIFI are still excellent results and are well below the industry average results of 1.08 as calculated utilizing yearbook data.

ETPL staff is mindful of the aging assets that make up its distribution system and will continue to monitor its assets and outages to ensure that the capital spend is appropriate to ensure that the number of outages does not continue to escalate to a point that it becomes an issue.

Measure: Asset Management – Distribution System Plan Implementation Progress:

2011	2012	2013	2014	2015	Target
n/a	n/a	n/a	In Progress	94%	n/a

As per 2015's Scorecard, ETPL has substantively completed its DSP and while it had not been filed with OEB as part of a COS filing at the time, it had become the guiding document for tracking ETPL's capital spend beginning in 2015. ETPL had detailed its five-year spend and projects and has measured itself on an annual basis with respect to actual spending level versus its plan. In 2015, ETPL spent approximately 94% of the dollars planned to be invested into its distribution system. In 2016, ETPL spent approximately 104% of the dollars planned to be invested into its distribution system.

ETPL will continue to file percentage completion annually as part of its RRR scorecard.

Measure: Cost Control – Efficiency Assessment:

2011	2012	2013	2014	2015	Target
n/a	4	3	3	3	n/a

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLP on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. ETPL has been placed in Group 3 from 2013-2015. Group 3 is defined as having actual costs within +/- 10 percent of predicted costs. Group 3 is considered "average efficiency" – in other words, ETPL costs are within the average cost range for distributors in Ontario.

Moving forward, ETPL aims to advance to the “more efficient” group. At this time, it is management’s expectation that efficiency performance will not decline.

Measure: Cost Control – Total Cost per Customer:

2011	2012	2013	2014	2015	Target
$634	$564	$610	$631	$656	n/a

This metric is calculated as the sum of ETPL’s capital and operating costs divided by the total number of customers that ETPL serves. The cost performance result in 2015 of $656 represents a 3.9% increase over 2014. However, it should be noted that the Total Cost per Customer has only increased 3.5% since 2010. Similar to most distributors in the province, ETPL has experienced increases in its total costs required to deliver quality and reliable services to customers. Province-wide programs such as Time of Use pricing, growth in wage and benefits costs for employees, as well as investments in new information systems technology, and growth of the distribution system have all contributed to increased operating and capital costs.

Despite all of the changes and progress embraced by ETPL, it has succeeded in keeping its cost of operations relatively flat and in doing so ETPL has been able to change its efficiency rating from 4 to 3. ETPL will continue to replace distribution assets proactively along a carefully managed timeframe in a manner than balances system risks and customer rate impacts.

Measure: Cost Control – Total Cost per Km of Line:

2011	2012	2013	2014	2015	Target
$35,056	$30,891	$32,792	$33,707	$34,342	n/a

Similar to the Total Cost per Customer, this measure is calculated by dividing the sum of ETPL’s capital and operating costs by the kilometers of line that ETPL operates in order to serve its customers. The 2015 rate for ETPL is $34,313 per kilometer of line, which represents a 1.9% increase over 2014. However, since 2010 the cost per kilometer of line has reduced by 2.0% due to the same cost drivers as detailed in the total cost per customer measure and a relatively static number of kilometers of line required to service ETPL customers between 2014 and 2015. This increase in cost per kilometers of line from 2014 to 2015 is due in part to an increase in assets, but can be directly attributable to the implementation of GIS and more accurate recording of its assets.

1.7.4 Public Policy

Measure: Conservation & Demand Management – Net Cumulative Energy Savings:

2011	2012	2013	2014	2015	Target
n/a	n/a	n/a	n/a	18.75%	27.63 GW

ETPL is progressing well towards achieving its target of 27.63 GWH, which was set in the 2015-2020 CDM framework. While the 2015 results are not exactly one year's worth of savings prorated on a linear basis, it is important to note that ETPL is in fact ahead of the results it had expected to achieve in the first year as filed in its official plan with the IESO.

ETPL is confident that it has the programs in place and the targeted achievable potential to reach its lofty savings goal by the end of the framework.

Measure: Connection of Renewable Generation – Renewable Generation Connection Impact Assessments Completed On Time:

2011	2012	2013	2014	2015	Target
25.00%	100.00%	n/a	n/a	100.00%	n/a

ETPL is pleased to report that it completed all of its connection impact assessments on time in 2015.

Measure: Connection of Renewable Generation – New Micro-embedded Generation Facilities Connected On Time:

2011	2012	2013	2014	2015	Target
n/a	n/a	100.00%	92.86%	100.00%	90.00%

In 2015, ETPL connected five new micro-embedded generation facilities (microFIT projects of less than 10 kW) 100% of time within the prescribed time frame of five business days. The minimum acceptable performance level for this measure is 90% of the time. ETPL works closely with its customers and their contractors to tackle any connection issues to ensure the project it connected on time.

1.7.5 Financial Performance

Measure: Financial Ratios – Liquidity: Current Ratio (Current Assets/Current Liabilities):

2011	2012	2013	2014	2015	Target
0.67	0.78	0.75	0.58	0.85	n/a

As an indicator of financial health, a current ratio greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio greater than 1 are often referred to as being “liquid”. The higher the number, the more “liquid” and the larger the margin of safety to cover the company’s short-term debts and financial obligations.

ETPL’s current ratio improved from 0.58 in 2014 to 0.85 in 2015 as a result of restructuring its debt, which moved it from current to long term. In May, 2015, ETPL also began to recover a large amount of regulatory assets in 2015 which managed to significantly improve cash flow. ETPL will continue to monitor its liquidity to ensure that it continues to improve in order to meet its financial obligations.

Measure: Financial Ratios – Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio:

2011	2012	2013	2014	2015	Target
1.06	1.23	1.19	1.05	1.59	n/a

In establishing rates, the OEB uses a deemed capital structure of 60% debt to 40% equity for electricity distributors. This deemed capital mix is equal to a debt to equity ratio of 1.5. ETPL's debt to equity ratio of 1.59 shows that it's in line with the deemed 60% to 40% capital mix.

Measure: Financial Ratios – Profitability: Regulatory Return on Equity – Deemed (included in rates):

2011	2012	2013	2014	2015	Target
8.68%	9.12%	9.12%	9.12%	9.12%	n/a

ETPL's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.12%.

Measure: Financial Ratios – Profitability: Regulatory Return on Equity - Achieved:

2011	2012	2013	2014	2015	Target
4.41%	8.43%	11.80%	10.63%	9.39%	n/a

ETPL's achieved return on equity was 9.39%, which is well within the +/- 3% range allowed by the OEB. The average return over the from 2012-2014 was 10.6%, which is also well within return included in ETPL's approved rates. The higher achieved returns in 2013 and 2014 were mainly due to higher revenue than forecast as a result of increased energy consumption and effective control of its operating costs.

1.7.6 Efficiency Assessment Forecast

The table below is ETPL's Efficiency Assessment forecast for the years of 2017 to 2021.

Erie Thames Powerlines Corporation

	2016	2017	2018	2019	2020	2021
	(History)	(Bridge)	(Test Year)			
Cost Benchmarking Summary						
Actual Total Cost	12,609,896	12,899,632	12,841,540	13,012,113	13,185,111	13,360,604
Predicted Total Cost	11,782,958	12,428,517	12,305,574	12,642,950	12,989,821	13,121,118
Difference	826,939	471,115	535,966	369,163	195,289	239,486
Percentage Difference (Cost Performanc	**6.8%**	**3.7%**	**4.3%**	**2.88%**	**1.49%**	**1.81%**
Three-Year Average Performance			4.9%	3.62%	2.88%	2.06%
Stretch Factor Cohort						
Annual Result	3	3	3	3	3	3
Three Year Average			3			

FINANCIAL INFORMATION

1.8.1 Audited Financial Statements

Copies of ETPL's 2015 and 2016 Audited Financial Statements can be found in Appendix1- J and 1- K.

1.8.2 Reconciliation of AFS

Reconciliations of ETPL's Audited Financial Statements to the annual RRR Trial Balance for 2014, 2015 and 2016 are provided as Attachments 1-L, 1-M and 1-N.

1.8.3 Annual Report and MD&A

Neither Erie Thames Powerlines Corporation nor ERTH Corporation publishes an annual report. Financial Statements are presented annually to the Shareholders at ERTH Corporations Annual Meeting.

1.8.4 Rating Agency Reports

ETPL does not have any agency ratings to report.

1.8.5 Tax Status

ETPL is not seeking any tax status changes in this Application.

1.8.6 Existing Accounting Orders/Departures

There are no existing accounting orders/departures affecting this Application.

1.8.7 Accounting Standards

In accordance with the Board's Filing Requirements, information for 2012 is presented in CGAAP standards. The year 2013 is presented in revised CGAAP standards. For 2014, 2015 and 2016 actuals and 2017 Bridge Year and the 2018 Test Year all financial information is provided under MIFRS.

1.8.8 Confirmation of Segregated Accounting

ETPL has segregated the following non-rate regulated activities from ETPL's rate regulated activity in accordance with the Board's Accounting Procedures Handbook for Electricity Distributors:

- Water Heater Rental Revenue
- Conservation and Demand Management programs
- Merger and Acquisition Activity

MATERIALITY THRESHOLDS

Chapter 2 Filing Requirements for Cost of Service rate applications published by the OEB on July 20, 2017 sets out the materiality levels based on the magnitude of the revenue requirement. ETPL's revenue requirement is greater than $10 million and less than $200 million. Therefore, ETPL's materiality threshold is 0.5% of distribution revenue requirement. ETPL's materiality threshold for the 2018 test year is $53,926 as calculated in the table below. ETPL has used a materiality threshold of $50,000 for the purposed of this Application.

ETPL's Materiality Threshold for 2018 Test Year

Description	2018 Test Year
Distribution Revenue Requirement	$ 10,785,163.00
Materiality Theshold	0.5%
Materiality Calculated	$ 53,926
Materiality Used	**$ 50,000**

DISTRIBUTOR CONSOLIDATION

The Minimum Filing Requirements reference that if a distributor has acquired or amalgamated with another distributor(s) since its last rebasing application, it must identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement. A distributor must list the exhibits of its application in which any incentives are discussed.

Erie Thames Powerlines Corporation herein confirms it has not acquired, been acquired, or amalgamated with another distributor(s) since our last rebasing application in 2012 (EB-2012-0121).

Exhibit 1: Administrative Documents

Tab 11 (of 11): Exhibit 1 Appendices

Attachment 1 (of 15):

1-A 2017 ETPL Business Plan

2017 Business Plan and Budget
Erie Thames Powerlines

Prepared by: Chris White
Date: December 1, 2016

Table of Contents

1. Strategic Objective

In keeping with the corporations objectives, Erie Thames Powerlines Corporation ("ETPL") will adhere to the following strategic objectives when pursuing new business opportunities and/or interacting with our stakeholders. The strategic objectives are as follows:

- ✓ Grow LDC and Manage ongoing attrition
- ✓ Sustainability
- ✓ Utility 2.0 Advancement
- ✓ Improve Consolidated Financial Performance/Reporting – "ONE TEAM", mind the store
- ✓ Employer of Choice
- ✓ Good Corporate Citizen
- ✓ Advocate for positive energy policy

Products and Services

ETPL is a **L**ocal **D**istribution **C**ompany currently servicing 18,500 customers in 14 communities across 4 counties, a partner you can count on. Our service territory stretches over 200 km as the crow flies from Port Stanley to Clinton. Serving the communities of Port Stanley, Aylmer, Belmont, Ingersoll, Thamesford, Embro, Beachville, Norwich, Otterville, Burgessville, Mitchell, Dublin and Clinton, we work hard to serve our customers. In these communities, ETPL's diverse customer base ranges from individual residences to large commercial and industrial users, including the General Motors CAMI Automotive Assembly plant located in Ingersoll.

ETPL is dedicated to providing its customers with safe and reliable electricity while keeping energy efficiency top of mind. Always looking to provide added benefit and value through innovation and technology; constantly seeking ways we can improve our services to meet or customer's needs.

Map Representing ETPL's current service territory:

As "**Your Home Town Utility"** our mission is to be seen as a valued community partner committed to delivering safe and reliable electricity while providing innovative and high-quality services and solutions to our customers.

Targeted Growth Strategy

Mergers & Strategic Partnerships

- Goderich Hydro (WCHE)
- St. Thomas Energy (STEI)

Aquisition

- Elimination of long term load transfer customers
- Aquire Hydro One assets closing the gap on a seamless distribution system within our region

Service Area Ammendments

- Expand franchise boundaries through service area ammendments as municipal growth occurs

Organic Growth

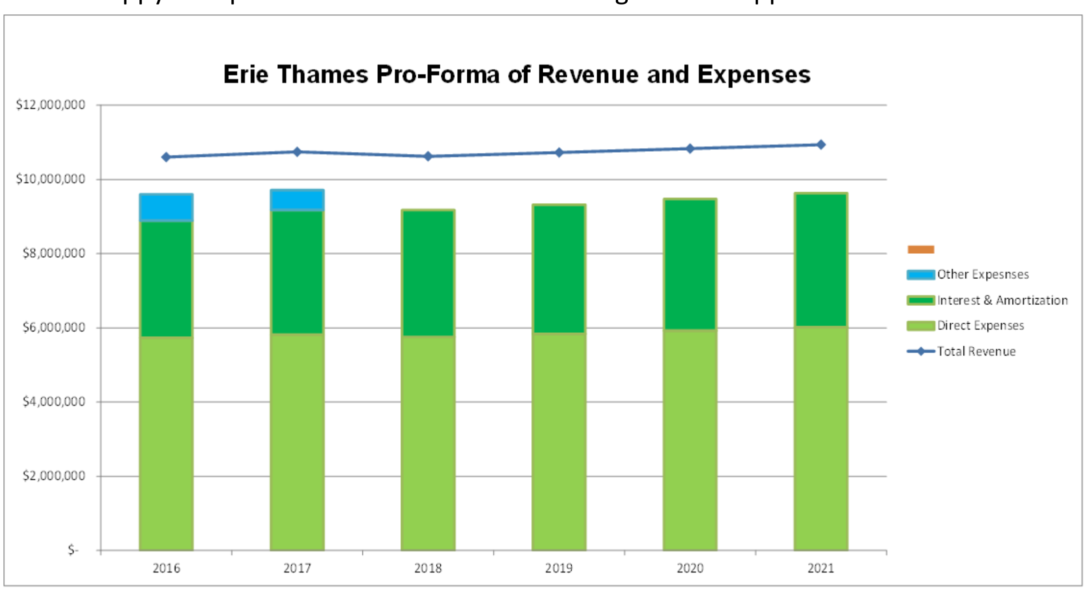
- Foster economic growth within our communities through competitive rates & value added services
- Renewable Generation
- Expansion of Scope for LDC
- Be the "Home Town Utility"

Erie Thames Powerlines is committed to pursuing growth opportunities in its electricity distribution businesses on a prudent and profitable basis, where it enhances the entity's strategic position, economies of scope and scale exist, and it adds value to our shareholders. ETPL continues to have a long term view for future growth, including the goal of acquiring neighbouring LDCs and Hydro One assets.

Financial Summary

The financial performance of ETPL is promising for 2016 and beyond. Section 6 provides the detailed budget for 2017, however outlined below is an illustration of the financial outlook for the coming year and beyond. For 2016 and 2017 we are showing an increase in costs due to additional consultant efforts required in filing our 2017 **C**ost **o**f **S**ervice rate application for 2018 rates.

ETPL is happy to report continued success in earning our OEB approved ROI.



2016 marked a successful and extremely busy year for ETPL. The team was heavily engaged with Goderich Hydro attending board meetings and ensuring support services were maintained in the highest regard. The excellent effort put forth by the team has led to an exclusivity agreement reached in late 2016 looking at a potential merger of ETPL and Goderich Hydro (WCHE).

- Zero lost time H&S incidents to report
    - Public Safety Survey 83.4%
    - Internal Safety Scorecard 86%
- Net Income tracking $200k ahead of budget
- Capex tracking to budget with board approved changes
- Customer Satisfaction Survey Results 89%
- ETPL continues to track ahead of Industry standards on our OEB Scorecard results
- $2 million spend on Fixed Distribution Assets - Maintain ongoing commitment to strengthen the distribution system
- Continue to maintain strong labour relations – employer of choice – zero arbitrations
- Installation of NET metering at 143 Bell St. location - 30kW
- OMS System implementation - ongoing for 2016/2017
- Ingersoll automated switch Main-Tie-Main installation - complete, communication issues to be resolved late 2016/2017
- Additional Fault Current Indicators installed in Ingersoll, Norwich, Tavistock & Port Stanley
- Norwich Supply Improvements
    - ETPL has continued discussions with Hydro One regarding necessary supply upgrades to the Norwich area
    - Hydro One has confirmed they have assigned budget dollars to relocate the off-road supply to Highway 59 making necessary improvement to the 20M1 feeder to Norwich
    - Upgrades to the supply will provide redundancy and automation opportunities

Highlights of 2015 OEB Scorecard Results posted in 2016

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2015 Erie Thames Powerlines connected 98.4% of its 189 new residential and small businesses to the distribution system within the required 5 day window that has been determined by the Ontario Energy Board. This result is not materially different than previous years as ETPL continues its solid performance over the past five years with this measure.

- **Scheduled Appointments Met On Time**

  Erie Thames Powerlines scheduled 12 appointments with its customers in 2015 to complete work requested by customers. Consistent with the prior year, the utility met 100% of these appointments on time, which exceeds the industry target of 90%.

- **Telephone Calls Answered On Time**

  In 2015 Erie Thames Powerlines customer service staff received approximately 27,545 calls and achieved a service level of 98.4% in answering those calls within 30 seconds, while only 1.6% of calls received were abandoned prior to customers speaking with an agent. Both of these results exceed the Ontario Energy Board's required level of service and are consistent with the performance of the call center in previous years.

Customer Satisfaction

- **First Contact Resolution**

  For Erie Thames Powerlines, First Contact Resolution was measured based upon actual calls received from customers with respect to the same or similar issue and calculated this number as a percentage of all customer contacts received that resulted in the generation of an issue and for which a care order was created. The result was that 99.8% of customer issues were dealt with on first contact.

- **Billing Accuracy**

  For the year 2015 Erie Thames Powerlines issued 224,578 bills and achieved a billing accuracy of 99.46%. This compares favourably to the prescribed OEB target of 98%.

- **Customer Satisfaction Survey Results**

  ETPL undertook its first customer satisfaction survey in 2015 and determined that its customers were 89% satisfied with its performance on a variety of measures. Erie Thames Powerlines customers indicated that improvements can be made to better communicate planned outages, improvements can also be made with respect to billing with educating our customers with respect to options available to them for payments, delivery of bills and general understanding of bills, finally a few customers felt our website needed to be updated however it is not clear if they have visited the newly launched website that went live shortly before the survey.

Safety

- **Public Safety**

  The Ontario Energy Board (OEB) introduced the Safety measure in 2015. This measure looks at safety from a customer's point of view as safety of the distribution system is a high priority. The Safety measure is generated by the Electrical Safety Authority (ESA) and includes three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04, and the Serious Electrical Incident Index.

- **Component A – Public Awareness of Electrical Safety**

  In 2015 Erie Thames Powerlines completed its survey of its customers with respect to public awareness of Electrical Safety. Erie Thames utilized a third party agency to survey its customers and ensure that and accurate sampling of its population was achieved. The results of this survey found that 83.4% of Erie Thames customers have strong awareness of electrical safety.

- **Component B – Compliance with Ontario Regulation 22/04**

  In 2014 and 2015, Erie Thames Powerlines was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety, and adherence to company procedures & policies. Ontario Regulation 22/04 - *Electrical Distribution Safety* establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service.

  In 2013, Erie Thames Powerlines was given a score of Needs Improvement in compliance with Ontario Regulation 22/04 (Electrical Distribution Safety). This score was given due to an interpretation issue with respect to the ESA requirement to ground utilizing a metal guard. The ESA resolved with Erie Thames Powerlines and other LDC's that the grounding was not required with the specifications used by Erie Thames however the resolution was not obtained until after the results were published.

- **Component C – Serious Electrical Incident Index**

  Erie Thames Powerlines has no reported serious incidents from 2010 to 2015. ETPL continues to be committed to safety in an effort to ensure this trend continues.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  Erie Thames Powerlines had a slight increase in 2015 of the number of hours that power to a customer is interrupted. The number of outage hours is still on the low side of the former target range provided by the Ontario Energy Board. Erie Thames results fell within the new LDC specific requirement of 0.99 for SAIDI however there has been an increase over the past two years that needs to be managed to ensure the trending is not a systemic issue within ETPL's distribution system as opposed to significant one time anomalous events.

  Erie Thames Powerlines continues to view reliability of electricity service as a high priority for its customers and as such conducts a vegetation management program that ensures the whole system is trimmed every three years. Similarly Erie Thames is dedicated to upgrading its assets to 27.6 kV in order to reduce its reliance on substations and thereby ensure that its reliability continue to be above average as aging stations are retired. This, combined with the Erie Thames Powerlines' senior management team's commitment to review the worst performing feeders on a quarterly basis in order to potentially improve reliability, will ensure customers continue to receive excellent reliability from Erie Thames' system.

- **Average Number of Times that Power to a Customer is Interrupted**

  Erie Thames average number of times that power to a customer is interrupted has increased slightly but is still at the low end of the former range of acceptable results set by the Ontario Energy Board. However, when compared to the new distributor specific target of 0.41 Erie Thames was marginally above the target and therefore is showing that this target is not met. While the result is portrayed as a target that is not met the results that Erie Thames has achieved with respect to SAIDI are still excellent results and are well below the industry average results for 2015 of 1.08 as calculated utilizing yearbook data.

  Erie Thames staff will continue to monitor its assets and outages and ensure that escalation of the number of outage does not continue to escalate to a point that it becomes an issue.

Asset Management

- **Distribution System Plan Implementation Progress**

  Erie Thames Powerlines has substantively completed its DSP and while it has not been filed with OEB as part of a COS filing it has become the guiding document for tracking our capital spend beginning in 2015. Erie Thames has detailed its 5 year spend and projects and has measured itself on an annual basis with respect to the actual spending level versus its plan. In 2015 Erie Thames spent approximately 94% of the dollars planned to be invested into its distribution system.

Cost Control

- **Efficiency Assessment**

  The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In 2015, for the second year in a row, Erie Thames Powerlines was placed in Group 3, where a Group 3 distributor is defined as having actual costs within +/- 10 percent of predicted costs. Group 3 is considered "average efficiency" – in other words, Erie Thames Powerlines costs are within the average cost range for distributors in the Province of Ontario.

- **Total Cost per Customer**

  Total cost per customer is calculated as the sum of Erie Thames Powerlines capital and operating costs and dividing this cost figure by the total number of customers that Erie Thames serves. The cost performance result for 2015 is $656 /customer which are a 3.9% increase over 2014.

  Erie Thames Powerlines Total Cost per Customer has increased by only 3.5% since 2010 despite the increase in 2015 over 2014. Similar to most distributors in the province, Erie Thames Powerlines has experienced increases in its total costs required to deliver quality and reliable services to customers. Province wide programs such as Time of Use pricing, growth in wage and benefits costs for our employees, as well as investments in new information systems technology and the renewal and growth of the distribution system, have all contributed to increased operating and capital costs. Despite these changes Erie Thames has succeeded in keeping its cost of operations relatively flat and in doing so has been able to change its efficiency rating from 4 to 3. Erie Thames Powerlines will continue to replace distribution assets proactively in a carefully managed timeframe in a manner that balances system risks and customer rate impacts.

- **Total Cost per Km of Line**

  This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that Erie Thames Powerlines operates to serve its customers. Erie Thames 2015 rate is $34,342 per Km of line, a 1.9% increase over 2014. However since 2010 the cost per kilometer of line has reduced by 2.0% due to the same cost drivers as detailed in the total cost per customer and a relatively static number of kilometers of line required to service ETPL customers between 2014 and 2015. This increase in kilometers of line from 2010 to 2015 is due in part to an increase in assets but can be directly attributable to the implementation of GIS and a more accurate updated recording of assets.

Conservation & Demand Management

- **Net Cumulative Energy Savings (Percent of target achieved)**

  Erie Thames Powerlines is pleased that it is progressing well towards achieving its target of 27.63 GWH in the 2015-2020 CDM framework. While our results in 2015 are not exactly one years' worth of saving prorated on a linear basis it is important to note that Erie Thames is in fact ahead of the results it had expected to achieve in the first as filed in its official plan with the IESO.

Financial Recap

Outlined in Section 7 is the 2016 forecast for Erie Thames Powerlines. A net income of $772,158 is anticipated. Among the key highlights are the following:

- While 2016 got off to a slow start for ETPL with respect to its financial results, ETPL is projected to meet its 2016 budgeted net income.
- During the first six months of 2016 ETPL lagged with respect to distribution revenue due to a relatively warm first quarter and the relatively cool start to summer with very little air conditioning load materializing until the end of June. The financial impact during the first half of the year was that ETPL was behind its revenue forecast in excess of $150,000 heading into the summer. This result coupled with approximately $100,000 of operating expenses spent in excess of budget meant that the results were over $250,000 behind budget.
- The hot summer resulted in an increase in usage by customers which increased revenues through three quarters and when coupled with decreases in operating costs meant that ETPL was only $45,000 behind budget with one quarter remaining. It is important to note that one of the biggest drivers for the reductions in operating costs was the capitalization of labour costs due to the many capital projects undertaken during the summer months. This impact is also seen in Q2 however it is less significant in Q1 given the weather constraints.
- ETPL is projecting the fourth quarter of 2016 to finish off with revenue coming in right on budget and operating costs to materialize slightly less than budgeted (inclusive of interest and amortization). The biggest driver for the reduction in operating costs is the fact that ETPL had budgeted $1,500,000 for its share of ERTH allocations while final ERTH allocation have been forecast to be $1,285,000 for 2016 given ERTH cost reductions through the course of the year. ETPL had been accruing these costs through the first three quarters as budgeted and the approximate $230,000 difference has impacted the results for Q4.
- Therefore, the final projected net income for 2016 is $1,002,000 with operating costs of $5,730,000 against revenues of $10,603,000.

3. SWOT Analysis

Strengths

- Strong resourcing complement with solid industry experience & local area knowledge
- Well positioned for next generation Utility 2.0
- New hires – highly skilled & tech savvy – skill set growing
- Technology - Leadership
- Ability to leverage affiliate company's experiences
- Relationships - Customers/Municipalities/LDC's/PWU
- "Home Town Utility" – responsive to customer needs – Regional Utility
- Conestoga PLT program located in Ingersoll

Weaknesses

- Management retirements over the next 5 years
  - Line Supervision replacement candidates
  - Aging workforce
  - Large Geographic Territory
- Metering / Field services
- Space – parking & building

Opportunities

- Mergers
  - Goderich
  - St Thomas
- Renewable Generation
- Expansion of LDC Services:
  - Street Lights
  - Water/Sewer
- Service Area Expansions
  - Recent success with Sifton PH2
  - Goderich Fusion Homes
- Leverage Technology Advancement
  - OMS, Silver Blaze - better customer experience
  - Strengthen our position with other LDC's by being leaders

Threats

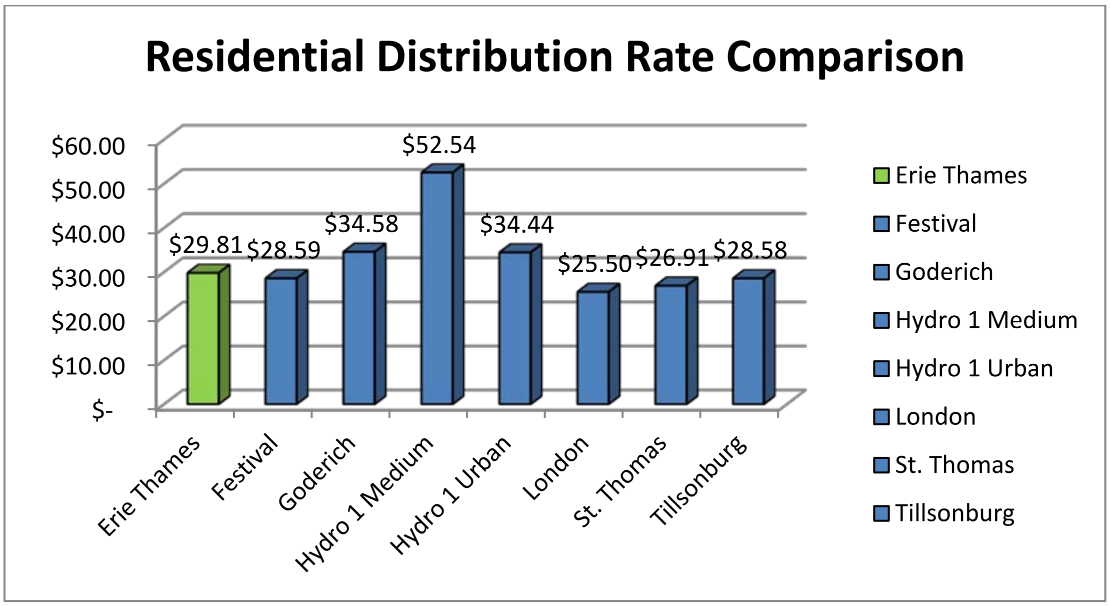
- St Thomas merger with another LDC
- Funding capital infrastructure renewal requirements
- Resource poaching by neighbouring LDC's
- Electricity price pressures – global adjustment
- Government reaction to Electricity Price Pressures
- Customer expectations
- Over Regulation

4. Market Analysis

Competitive Analysis

Erie Thames is a non-contiguous LDC spacing 4 counties. Despite our vast service territory ETPL continues to perform well with our neighbours and industry and peers groups:

Rate Analysis



2015 OEB Annual Scorecard Results Posted in 2016

In 2015, Erie Thames Powerlines performed exceptionally well with respect to its KPI targets and improved many of its results when compared to 2014 performance. Bad weather and increasing failure rates for aging distribution assets resulted in a slight decrease in reliability measures for 2015. However, Erie Thames remains well under the former mandated targets and continues to provide excellent reliability for our customers which are significantly better than the industry average.

Scorecard - Erie Thames Powerlines Corporation

9/12/2016

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		99.30%	98.80%	98.80%	99.40%	98.40%	down	90.00%	
		Scheduled Appointments Met On Time		98.10%	100.00%	100.00%	100.00%	100.00%	up	90.00%	
		Telephone Calls Answered On Time		98.10%	94.60%	95.80%	95.50%	98.40%	up	65.00%	
	Customer Satisfaction	First Contact Resolution					99.7%	99.85			
		Billing Accuracy					99.85%	99.46%	down	98.00%	
		Customer Satisfaction Survey Results					100 %	89%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness						83.40%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	C	NI	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	flat		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	flat		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.53	1.47	0.41	0.59	0.73	down		0.99
		Average Number of Times that Power to a Customer is Interrupted [2]		0.75	0.31	0.20	0.30	0.48	flat		0.41
	Asset Management	Distribution System Plan Implementation Progress					In Progress	94%			
	Cost Control	Efficiency Assessment			4	3	3	3			
		Total Cost per Customer [3]		$634	$564	$610	$631	$656			
		Total Cost per Km of Line [3]		$35,056	$30,891	$32,792	$33,707	$34,342			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]						18.75%			27.63 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		25.00%	100.00%			100.00%			
		New Micro-embedded Generation Facilities Connected On Time				100.00%	92.86%	100.00%	flat	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.67	0.78	0.75	0.58	0.85			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.06	1.23	1.19	1.05	1.59			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.68%	9.12%	9.12%	9.12%	9.12%			
			Achieved	4.41%	8.43%	11.80%	10.63%	9.39%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

Legend: 5-year trend: up, down, flat. Current year: target met, target not met

Demographics and Target Market

Given our geographic proximity in Elgin County and Huron County the similarity of our communities, we feel that a combination of STEI, WCHE and ETPL would position us as a strong regional utility and spearhead the potential for further consolidation in our surrounding areas. Moreover, we are confident that such a combination would greatly increase the value to our respective shareholders by delivering tangible efficiencies and considerable economic benefits. Our rationale for these conclusions is expanded upon below.

- Similar Customers, Similar Municipalities – We believe that STEI's and WCHE's customer base is a perfect fit with ETPL's due to the geographical proximity of our service territories and the similar demographics of our communities. We serve similar customer bases that appreciate a local presence, courteous customer care, and reliable, safe and community-focused delivery of electricity at competitive distribution rates.
- Geographic Proximity – STEI, WCHE and ETPL are located in Elgin County and Huron County. We think that a combination of STEI, WCHE and ETPL is a compelling picture of a strong regional LDC in southwestern Ontario.
- Strategic Value of a Regional Utility – In addition to the resulting efficiencies and economies of scale, we believe that a growing regional LDC footprint will be beneficial during the inevitable consolidation of the Ontario distribution sector. Should we be interested in selling our distribution assets in the future, we are confident that a combined STEI, WCHE and ETPL will be more valuable to potential purchasers as a strong regional utility. In the meantime, we will have

the scope and resources to thrive while comparable LDCs struggle under the weight of the increasing regulatory and cost burdens.

- Minimum Efficient Size – As highlighted in the recent report of the Distribution Sector Review Panel, we believe that municipalities should look to grow their LDC service territory where it makes good business, operational and financial sense. This growth will result in operational efficiencies, economies of scale and the platform to deliver the technological and investment demands of a future LDC. We are confident that a utility with 40,000 customers – which would be achieved via a merger of STEI, WCHE and ETPL – could capture many of these benefits.
- Minimal Rate Harmonization Impact – The distribution rates of STEI, WCHE and ETPL are similar which mitigates the risk of negative rate impacts associated with rate harmonization. As well as a merged LDC the efficiency gained will mitigate future rate increases for our customers.
- Similar Back-Office and IT Platforms – STEI, WCHE and ETPL share many of the same back-office and IT systems, including billing and CIS (Harris), financial (Microsoft GP), smart metering infrastructure (Elster) and operational data storage (MeterSense). These IT synergies will result in tangible cost-savings in the event of a merger of STEI, WCHE and ETPL.
- Opportunities for Job Growth – A merger of ETPL and STEI would result in no job losses and a strong potential for job growth. We also believe that a merger of STEI, WCHE and ETPL will spur on more strategic long term relationships with other LDC's in the region that will lead to increased value for our shareholders.

5. 2017 Goals and Opportunities

Goals

Outlined below are a series of Goals that have been identified for ETPL and are reflected in the 2017 budget and pro-forma.

- Zero lost time H&S incidents – Safety First
- Maximize MBRR – continue to foster innovation and seek operational efficiencies
- Merger with Goderich Hydro and or St Thomas Energy 25,000 – 40,000 customers
- Mitigate Electricity Rates – Leverage CDM for community outreach
- Continue to foster strategic relations within the industry – participation on industry councils
- Foster positive Shareholder Relations/Communications – CEO Breakfast meetings
- Submission of COS application (April) with the completion of the 5 year **D**istribution **S**ystem **P**lan
- Continue to maintain strong Labour relations – employer of choice
- Strategy for distribution system automation & smart grid - (dual automated supply to Norwich)
- Implementation of new H&S system with contractor compliance module
- $1.65 million spend on Fixed Distribution Assets (+$384,000 payment for Aylmer TS) - Maintain System Performance Health
- Energization of second feeder to the Town of Aylmer
- Aylmer Ethanol Plant, proposed expansions – possible dedicated feeder being proposed
- Reconcile Long Term Load Transfers (LTLT); ETPL gaining approx. 60 customers
- Ongoing Smart Grid Improvements; SCADA, OMS, etc.
- PME points tied into SCADA system for better telemetry

- Programming of alarms, email alerts etc.
- Further implementation of electronic inspections & maps
- Work closer with ETPL's affiliates in becoming a leading edge utility

Opportunities

- Operational Consolidation through Mergers Opportunities
    - Merged LDC able to keep efficiency gains for up to 10 years
- Enhance Strategic Partnerships
    - CHEC Group (Cornerstone Hydro Electric Concepts Inc.)
    - MAS: ETPL, Goderich, Hawkesbury, Tillsonburg
- FIT 4, FIT 5 Opportunities

6. Long Term Goals

- Continue Strategic Growth for ETPL
- Maintain Competitive Electricity Rates
- Continue to evolve value add to customer
    - Social Media
    - Outage Management
    - GIS
    - Distribution Automation
- Enhance & automate supply interconnect redundancy to small communities
- Continued focus on quality of service
- Increase Industry Involvement (EDA Executive)
- Implement Workflow Automation
- Decommission Mitchell Municipal Substation, Ingersoll MS#1 - 2-3 years
- Community Energy Partnerships
- Green Revolution – Greener Fleet – Paperless

7. Business Development and Communications Strategy

Included in the plan for ETPL is a strategy to further engage our stakeholders through various new initiatives. Also key to our ongoing promotional strategy is leveraging relationships through industry conferences and events.

- Website enhancements and marketing activities
- Social Media
- Shareholder News Letters
- CEO Breakfast – update shareholders on the activities of ERTH/ETPL
- Silver Blaze – customer web based porthole to access billing data
- Online form Submission – better the customer experience
- Outage Management System (OMS) – provide real time outage information to the organization to better manage emergency situations and push out information to our customers
- Participation in industry and events
    - EDA AGM Enercom delegation

- EDIST delegation
- Mearie Conference – HR & Risk management
- EDA Councils (Operations, Communications, Regulatory & Finance)
- LAC – Conestoga Powerline Technician Program
- Area 1, health and safety group

Operations Plan

Location

Currently, the majority of staff are based out of 143 Bell Street, Ingersoll. Staff in Ingersoll support all business functions for all of Erie Thames customers in the areas of finance, regulatory, billing, call centre, engineering and operations. Ingersoll also operationally services the town of Ingersoll, Beachville, Embro, Thamesford, Tavistock, Norwich, Otterville and Burgessville. ETPL also has two remote service centres supporting line staff functions located at; 50 Arthur Street, Mitchell servicing the town of Mitchell, Dublin and Clinton and 280 Elm Street, Aylmer servicing Aylmer, Belmont and Port Stanley.

ETPL has been notified by West Perth that they will not be renewing our lease in 2017 for 50 Arthur Street in the town of Mitchell however they have indicated they will work with us to provide a month by month extension for a maximum 5 month period. The extension will allow time for ETPL to advance merger discussions with Goderich Hydro. If merger discussions are successful ETPL has proposed to move the Mitchell service centre to 240 Huckins Street in the town of Goderich. In 2016 ETPL purchased a lot at 152 Clarke Street in an industrial park in the town of Mitchell as a backup plan in the event the merger between ETPL and Goderich Hydro is not successful to which temporary job trailers would be utilized for the remainder of 2017.

Organization Structure/Staffing

Outlined below is the 2016 organizational chart for ETPL anticipating no changes for 2017. ETPL has done a good job over the last few years planning our current organizational structure to support attrition over the next 5 years creating opportunities for staff to move into more senior roles as natural attrition occurs.

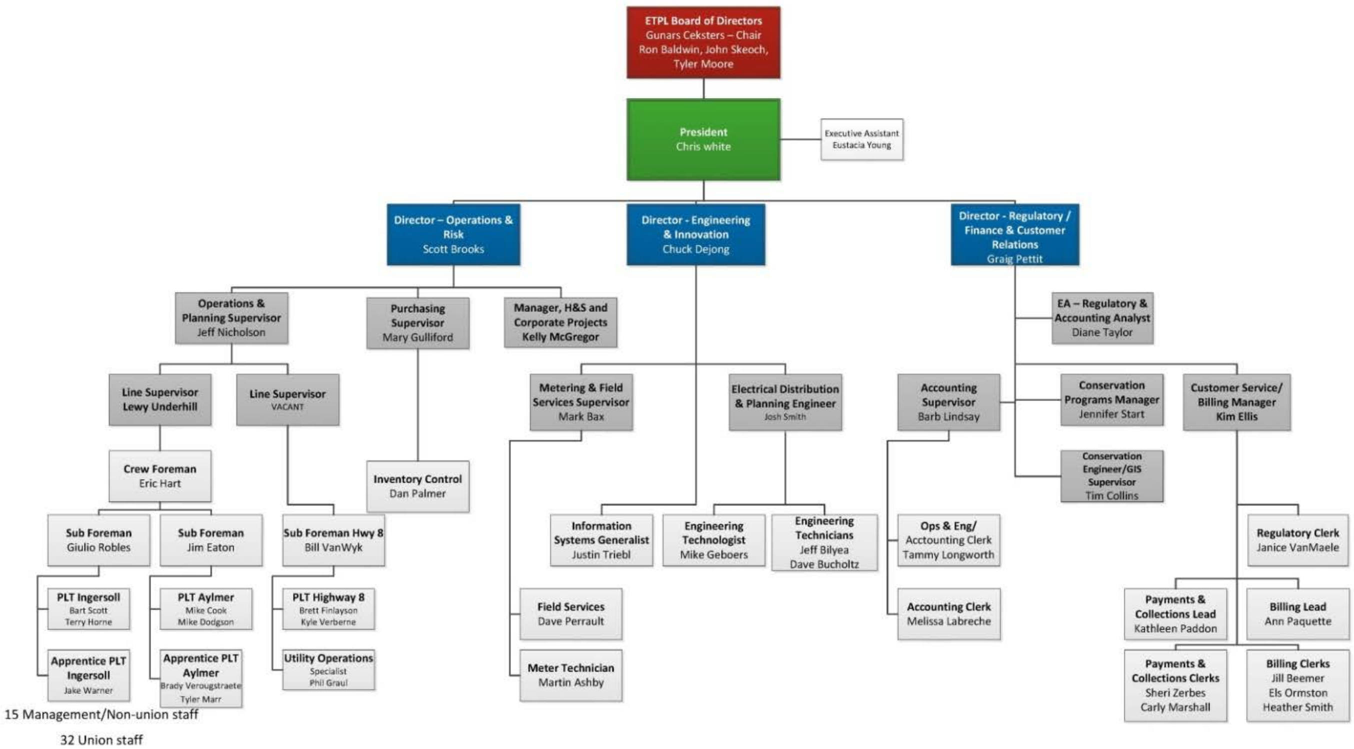
ETPL anticipates 2 senior managers and 2 – 3 supervisors retiring in the next five years to which the organization structure will support a smooth transition.

ETPL also estimates approximately 25% of its unionized staff will retire over the next five years; those positions will be filled as the vacancies occur.

ETPL is anticipating no new net hires in 2017 subject to merger discussions with WCHE. If merger discussions with WCHE are unsuccessful ETPL will need to hire a line apprentice at our Hwy 8 Operations in the 3rd quarter to deal with ongoing attrition.

ERIE THAMES POWERLINES

Proposed ORG Chart 2017:



Critical Suppliers/Partners

Outlined below is a list of critical suppliers and partners:

- ERTH – related party for billing support, back office hosting and corporate management services
- ERTH / JMar – overflow capital work and emergency storm response
- Neighbouring LDC's - Mutual aid support
- Southwest Ontario Buying Group (7 LDC's partnering together for purchasing power)
- Anixter – pole line hardware and wire supplier
- CES – transformer supplier
- Guelph Utility Pole – hydro pole supplier
- Zap's Tree Service – vegetation removal and line clearing
- Commercial Truck Service – utility truck servicing
- CC Dance – hydrovac services

8. Budgets and Projections

- In 2017 ETPL has budgeted a net income before tax of approximately $1,030,000. This net income is driven off of expected revenues from operations of $10,743,000 a 1.3% increase over the 2016 projected amounts. This revenue figure incorporates an IRM rate change anticipated in May of 2017 and attempts to normalize consumption figures to ensure that revenues are not overly inflated due to the hot summer of 2016.

- Operating expenses are projected to increase in 2017 by approximately $88,000 or 1.5%. This change incorporates an increase in labour costs of 3% of which 2% is COLA increases the last 1% is due to a decrease in capitalized labour resulting from less capitalized work completed by staff due to Aylmer TS costs to be paid to Hydro One. Included in operating costs is also an increase related to work to be completed for the cost of service rate application in the amount of $150,000. The last significant change that drives the operating cost increase relates to decreases in affiliate allocations of approximately $250,000.
- Total labour costs for 2017 are forecast to be $4,736,000 of which $3,196,000 will be expensed as operating costs, the remaining costs will be capitalized or recovered through ETPL's CDM programs and will not impact the P&L statement. This labour costs incorporates the annual COLA increase as well as all of the relevant changes in the corporate organizational structure that has occurred in the last quarter of 2016, and two CO-OP students and one new line apprentice for Hwy 8 (Mitchell Operations) for a portion of the year (this apprentice will not be hired in the event of a successful merger with WCHE).
- 2017 represents the last year that ETP will have to adjust its profit and loss statement for the difference between IFRS amortization and CGAAP amortization that is actually recovered in rates. The forecast in 2018 removes the CGAAP IFRS adjustment from the statement and normalizes distribution revenue to recover amortization on an IFRS basis.
- At first glance it looks as though ETPL will not get a rate increase in 2018 but rather a rate decrease, however if the reduction in net income in 2016 and 2017 were to be moved up the P&L statement and applied against Distribution Revenue then the change in 2018 revenue would in fact be significant.
- The remaining forecasted amount for 2018 through to 2020 is derived utilizing formulaic changes in costs and revenues to cover off IRM rate increases and inflation applied to expenses.

Capital Budget Summary

Erie Thames utilizes a sophisticated tool called the Optimizer to assist us in asset management plan. By optimizing investment decisions for asset lifecycle management, ETPL helps satisfy network reliability and capital investment demands while reducing business risks. The Optimizer dynamically scrutinizes asset performance and lifecycle data against corporate objectives encompassing ROI, reliability, safety, reputation, environment and growth. Fully leveraging existing data sets and asset/work management programs, the Optimizer mitigates risk and drives prioritization to new analytical levels as it accurately charts end-of-life curves and provides multiyear rolling plans to augment replace and/or renew critical assets.

ERIE THAMES POWERLINES

ETPL has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The table below summarizes our proposed capital expenditures for 2017.

Optimization of Capital Costs

Included in the capital plan for 2017 is the final installment payment of $383,343 to Hydro One for the new breaker position at the Aylmer Transmission Station.

- Total Project Portfolio Analyzed - $4,854,775
- 40 Projects Optimized – 13 Deferred
- $3.2m capex - $326.5k opex
- Overall Corporate Strategic Value Achieved – 78%

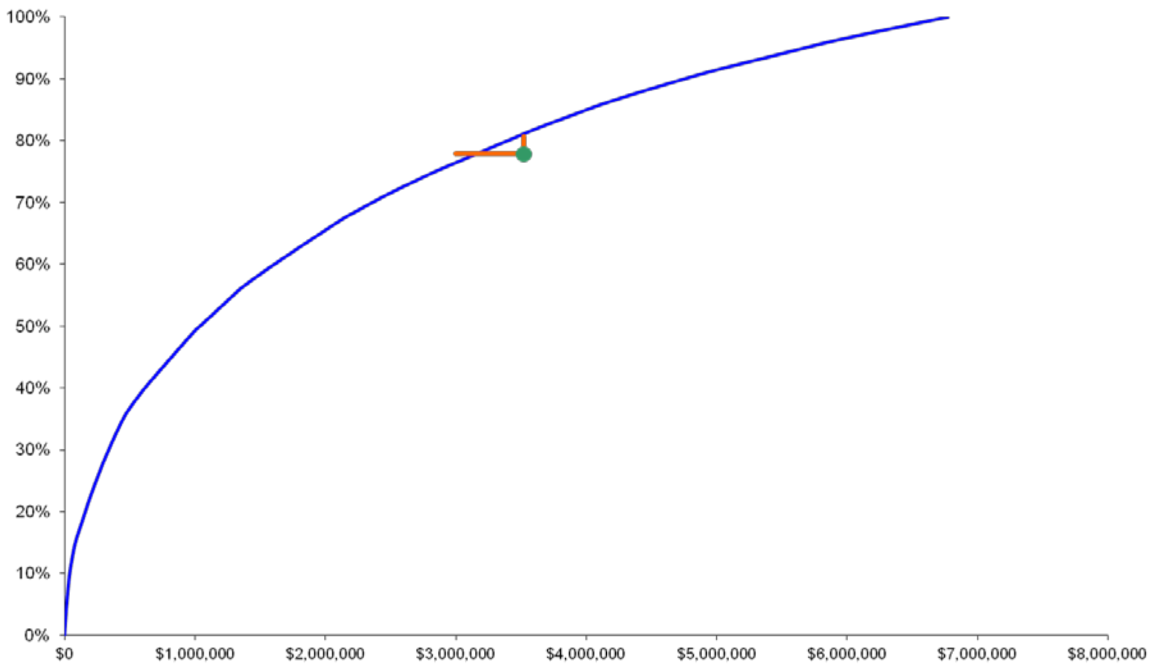
Fixed Distribution Asset Project Detail

General			$323,000
	ALL-OHUPG-Planned Pole Replacements	$123,000	
	ALL-UNPLD-Unplanned Capital Investments	$150,000	
	ALL-LTLT-Long Term Load Transfers	$50,000	
Ingersoll Operations	BEA-OHCON-Station Egress and Crossing	$120,000	$330,292
	TAV-STNUPG-Station Upgrades (PH2)	$100,000	
	^^ OTT-UGUPG-Grove & Maple	$110,292	
Aylmer Operations	AYL-UGCONV-Talbot St. E.-King to Queen (PH2)	$185,000	$621,200
	AYL-STATION-New Feeder Egress & PME	$304,200	
	AYL-OHCONV-South Street, Caverly to Rutherford	$132,000	
Mitchell	CLI-OHCONV-Bayfield Road	$274,500	$274,500

Operations			

Optimize Capex, Opex Budget

Value Achieved 78%



9. Acronyms List

Acronym	**Description**
CIS	Customer Information System: Software used for Billing and Customer relationship management for Utilities. Product used by ERTH is NorthStar via an Enterprise Agreement with Harris Utilities.
ESA	Electrical Safety Association
GIS	Geographical Information System
IESO	Independent Electricity System Operator
LDC	Local Distribution Company
MAS	Used to describe the head end system to capture the Elster interval meter data.
MDMR	Meter Data Management System. System operated by the IESO (Independent Electricity System Operator) which is provincially managed.
ODS	Operational Data System. System used to manage interval metering data. ERTH is currently deploying the MeterSense product, owned by Harris Utilities.
OEB	Ontario Energy Board
OMS	Outage Management System. System used to track, monitor and manage power outages
OPA	Ontario Power Authority
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
STEI	St. Thomas Energy Inc.

Attachment 2 (of 15):

1-B Distribution Licence Amended May 25, 2017

Electricity Distribution Licence

ED-2002-0516

Erie Thames Powerlines Corporation

Valid Until

December 17, 2023

Brian Hewson
Vice President, Consumer Protection & Industry Performance
Ontario Energy Board

Date of Issuance: December 18, 2003
Date of Last Amendment: May 25, 2017

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

Commission de l'énergie de l'Ontario
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LIST OF AMENDMENTS

Board File No.	Date of Amendment
EB-2002-0462	July 9, 2004
EB-2005-0304	September 9, 2005
EB-2007-0659	September 5, 2007
EB-2007-0774	November 29, 2007
EB-2009-0375	January 8, 2009
EB-2010-0215	November 12, 2010
EB-2010-0338	January 31, 2011
EB-2011-0010	March 17, 2011
EB-2011-0122	June 14, 2011
EB-2010-0386	June 30, 2011
EB-2011-0085	November 15, 2011
EB-2014-0324	December 18, 2014
EB-2015-0254	November 19, 2015
EB-2016-0015	January 28, 2016
EB-2017-0156	May 25, 2017

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1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**Conservation and Demand Management**" and "**CDM**" means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

"**Conservation and Demand Management Code for Electricity Distributors**" means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

"**distribution services**" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**IESO**" means Independent Electricity System Operator;

"**Licensee**" means Erie Thames Powerlines Corporation

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Net Annual Peak Demand Energy Savings Target**" means the reduction in a distributor's peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

"**Net Cumulative Energy Savings Target**" means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014;

"**OPA**" means the Ontario Power Authority;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Provincial Brand**" means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

14.3 The licensee shall inform the Board as soon as possible of any material changes to the service agreement with Erie Thames Service Corporation (the "Service Agreement").

14.4 If either party to the Service Agreement provides notice of its intention to exercise a right to terminate or discontinue any services under the services agreement, the Licensee shall:

a) Immediately notify the Board in writing of the notice; and

b) provide a plan to the Board as soon as possible, but no later than ten (10) days after the receipt of the notice, as to how the affected distribution services will be maintained in compliance with the terms of this Licence.

14.5 In the event of termination of the Service Agreement for any reason, the Licensee shall:

a) ensure there is no interruption of distribution services to the consumers as a result of the termination;

b) notify the Board of the name of the new company that will provide the distribution services; and

c) file with the Board the distribution services agreement with the new company.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on December 18, 2003 and expire on December 17, 2023. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

21 Conservation and Demand Management

21.1 2011-2014 Conservation and Demand Management Framework

21.1.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 5.220 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 22.970 GWh (collectively the "CDM Targets"), over a four-year period beginning January 1, 2011.

21.1.2 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee's service area ("Board-Approved CDM Programs");

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee's service area under contract with the OPA ("OPA-Contracted Province-Wide CDM Programs"); or

c) a combination of a) and b).

21.1.3 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee's service area.

21.1.4 The Licensee shall comply with the rules mandated by the Board's Conservation and Demand Management Code for Electricity Distributors.

21.1.5 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee's own brand or marks.

21.2 2015-2020 Conservation and Demand Management Framework

21.2.1 The Licensee shall, between January 1, 2015 and December 31, 2020, make CDM programs, available to customers in its licensed service area and shall, as far as is appropriate and reasonable having regard to the composition of its customer base, do so in relation to each customer segment in its service area ("CDM Requirement").

21.2.2 The CDM programs referred to in item 21.2.1 above shall be designed to achieve reductions in electricity consumption.

21.2.3 The Licensee shall meet its CDM Requirement by:

a) making Province-Wide Distributor CDM Programs, funded by the Ontario Power Authority (the "OPA"), available to customers in its licensed service area;

b) making Local Distributor CDM Programs, funded by the OPA, available to customers in its licensed service area; or

c) a combination of a) and b).

21.2.4 The Licensee shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to other licensed electricity distributors upon request.

21.2.5 The Licensee shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to any other person upon request.

21.2.6 The Licensee shall report to the OPA the results of the CDM programs in accordance with the requirements of the licensee's "CDM-related" contract with the OPA.

22 Pole Attachments

22.1 The Licensee shall provide access to its distribution poles to all Canadian carriers, as defined by the Telecommunications Act, and to all cable companies that operate in the Province of Ontario. For each attachment, with the exception of wireless attachments, the Licensee shall charge the rate approved by the Board and included in the Licensee's tariff.

22.2 The Licensee shall:

a) annually report the net revenue, and the calculations used to determine that net revenue, earned from allowing wireless attachments to its poles. Net revenues will be accumulated in a deferral account approved by the Board;

b) credit that net revenue against its revenue requirement subject to Board approval in rate proceedings; and

c) provide access for wireless attachments to its poles on commercial terms normally found in a competitive market.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. The former Villages of Belmont and Port Stanley as of December 31, 1997, now in the Municipality of Central Elgin

2. The Town of Aylmer as of January 1, 1998, also outlined on a map filed on August 6, 2003 as part of the application.

3. The Town of Ingersoll as of December 31, 2000.

4. The former Village of Beachville as of December 31, 1974, now in the Township of South-West Oxford.

5. The former Town of Tavistock as of December 31, 1974, now in the Township of East Zorra-Tavistock.

6. Lands in the Township of East Zorra-Tavistock described as:

    - Plan of Subdivision 32T-89005; or PIN 00246-0129: Part of Lot 125, Southeast of Woodstock Street and South of Hope Street, Plan 307 and part of Lot 35, Concession 12; Designated as Parts 1, 2, 3, 4, 5, 6, 7 and 8, 41R7562

7. The former Villages of Norwich, Otterville & Burgessville as of December 31, 1974, now in the Township of Norwich.

8. The Villages of Embro & Thamesford as of December 31, 1974, now in the Township of Zorra.

9. Ottercreek Golf and Country Club; Legal Description for PIN 00052-0502, Part of Lot 13, Concession 9, Designated as Part 1, 41R-5735, Lots 1, 2, 3, 4, 5, 6, 7, 8, 9 and 10, East of James Street, Plan 129, Lot 137 and Part of Lots 139 and 144, Plan 388 and Part of Lot 12, Concession 9, Subject of easement in favour of Ontario Hydro over Part 3, 41R-5736 as in Plan 1743 subject to easement in favour of the Corporation of the Township of Norwich over Part of Lot 144, Plan 388, Designated as Part 3, 41R-6035, Township of Norwich, County of Oxford, formerly the Village of Otterville.

10. Part Lot 17 and 18, Concession 1 (West Oxford), Township of Ingersoll.

11. Part Lots 34 and 35, Concession 13 (East Zorra), in the Township of East-Zorra Tavistock.

12. Part Lot 7, Concession 4 (North Norwich), in the Village of Norwich.

13. The boundary of the former Town of Clinton as of December 31, 2000, now part of the Municipality of Central Huron.

14. The customer located at 80212 Baseline Road in the former Township of Hullett now in the Municipality of Central Huron.

15. The Town of Mitchell as of December 31, 1997.

16. The Police Village of Dublin as of December 31, 1997.

17. West Perth Packers Ltd., Part of Lot 23, Concession 2, Fularton Ward as Part 9 of Reference Plan 44-R-3945.

18. Ball Park, Part of Lot 24, Concession 2, Fularton Ward as Part 6 of Reference Plan 44-R-3945.

19. Sewage Treatment Plant, Part of Lot 23 and 24, Concession 2, Fularton Ward as Part 7 of Reference Plan 44-R-3945.

20. Vacant Land (In Front of Sewage Treatment Plant), Part of Lot 23 and 24, Concession 2, Fularton Ward as Part 8 on Reference Plan 44-R-3945.

21. Part Lot 19, Concession 1 (West Oxford), Town of Ingersoll, Excluding: Lots 56 to 112, Lots 119 to 131, and Blocks 137, 138, 139 and 140.

22. 1 Chamberlain Avenue, Ingersoll, Ontario - Block 63; Plan 41M-309, in the Town of Ingersoll, County of Oxford.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

1. The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it.

2. Erie Thames Powerlines Corporation's Electricity Distribution Licence (ED-2002-0516), specifically Schedule 3 of the licence, is amended to reflect the exemption from the requirements of section 6.5.4 of the Distribution System Code as per Erie Thames Powerlines Corporation's request set out in the application.

3. The Licensee is exempt from the requirement for meter enrollment testing as of the mandatory date for time-of-use pricing for RPP consumers with eligible time-of-use meters as required under the Standard Supply Service Code for Electricity Distributors. This exemption expires February 28, 2011.

APPENDIX A MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the

IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

Attachment 3 (of 15):

1-C Certification of Evidence

ERIE THAMES POWERLINES
Your Home Town Utility

Certification of Evidence

I, Chris White, President of Erie Thames Powerlines Corporation certify that the evidence filed is accurate, consistent and complete to the best of my knowledge.

Chris White, President & CEO,

Sept 12, 2017
Date

PO Box 157, 143 Bell Street, Ingersoll, ON N5C 3K5
T: 519-485-1820 · TF: 877-850-3128 · Fax: 519-485-5838
www.eriethamespower.com
ECRA/ESA 7008969

Attachment 4 (of 15):

1-D Conditions of Service

CONDITIONS OF SERVICE

January 2012
Version 6.2

CONDITIONS OF SERVICE

TABLE OF CONTENTS

SECTION 1 INTRODUCTION

1.1 Identification of Distributor and Territory

Erie Thames is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity.

Erie Thames is licensed by the Ontario Energy Board “OEB” to distribute electricity to Customers in the service area described in Erie Thames Distribution License, ED-2002-0516 (the “Licence”).

Additionally there are requirements imposed on Erie Thames by the various codes referred to in the License and by the *Electricity Act* and the *Ontario Energy Board Act*.

1.1.1 General

Nothing contained in this document or in any contract for the supply of electricity by Erie Thames shall prejudice or affect any rights, privileges, or powers vested in Erie Thames by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any regulations thereunder.

Erie Thames will normally provide one electrical service to each customer location at a nominal service voltage.

Modifications to an existing service must comply with the requirements of the standards in effect at the time of the modifications.

The customer or their authorized representative must make application for new or upgraded electric services and temporary power services.

The customer or their representative shall consult with Erie Thames concerning the availability of supply, the voltage of supply, service location, metering and any other details. These requirements are separate from and in addition to those of the Electrical Inspection Authority. Erie Thames will confirm, in writing, the Characteristics of Electric Supply available at a specific site.

The customer is required to provide Erie Thames sufficient lead-time in order to ensure:

(a) the timely provision of supply to new and upgraded premises or
(b) the availability of adequate capacity for additional loads to be connected in existing premises.

If special equipment is required or equipment delivery problems occur then longer lead times may be necessary. The customer will be notified of any extended lead times.

Customers will be required to pay the cost of repair or replacement of Erie Thames equipment that has been damaged through the customers’ action or neglect.

The supply of electricity is conditional upon Erie Thames being permitted and able to provide such a supply, obtaining the necessary apparatus and material, and constructing works to provide the service. Should Erie Thames not be permitted to supply or not be able to do so, it is under no responsibility to the customer whatsoever.

The Customer shall not build, plant or maintain or cause to be built, planted or maintained any structure, tree, shrub or landscaping that would or could obstruct the running of distribution lines, endanger the equipment of Erie Thames, interfere with the proper and safe operation of Erie Thames's facilities or adversely affect compliance with any applicable legislation in the sole opinion of Erie Thames.

Prior to commencing any service work, the customer must consult with Erie Thames to ensure compliance with current requirements.

Customers may be required to pay Capital Contributions for the addition of new electrical services based on the requirements of the Distribution System Code.

1.2 Related Codes and Governing Laws

Erie Thames and the Customer shall comply with all Applicable Laws, including the provisions of the latest editions of the following documents:

1. *Electricity Act, 1998*
2. *Ontario Energy Board Act, 1998*
3. *Distribution Licence* ED-2002-0526
4. *Affiliate Relationships Code*
5. *Distribution System Code*
6. *Retail Settlements Code*
7. *Standard Service Supply Code*
8. *Transmission System Code*

In the event of a conflict between this document and the Distribution Licence or regulatory Codes issued by the OEB, or the *Electricity Act*, the provisions of the Act, the Distribution License and associated regulatory Codes shall prevail.

When planning and designing for electricity service, Customers and their agents must refer to all applicable provincial and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. The work shall be conducted in accordance with the Ontario Occupational Health and Safety Act, the Regulations for Construction Projects and the E&USA (or the OHSC Safety) rulebook.

1.3 Interpretations

In these Conditions, unless the context otherwise requires:

- *Headings and underlining are for convenience only and do not affect the interpretation of these Rules.*
- *Words referring to the singular include the plural and vice versa.*
- *Words referring to a gender include any gender.*

1.4 Amendments and Changes

The provisions of these Conditions of Service and any amendments made from time to time form part of any Contract made between Erie Thames and any connected Customer, Generator or their agents.

In the event of changes to this Conditions of Service, a Public notice shall be made in the form of a customer bill note and/or a notice on Erie Thames Website.

The Customer is responsible for contacting Erie Thames to ensure that the Customer has, or to obtain the current version of the Conditions of Service.

1.5 Contact Information

For general inquiries, Erie Thames Powerlines can be contacted during normal business hours: Monday to Friday between 8:30 am to 4:30 pm at 519-485-1820 or toll free 1-877-850-3128, by email at info@eriethamepower.com or by writing to:

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

For emergency purposes during or after normal business hours, Customers can call Erie Thames at 1-877-850-3128.

1.6 Customer Rights

In those instances where the Customer will own their secondary or primary service, the Customer has the right to hire a Contractor to supply and install the service.

The customer has the right to demand identification from any person purporting to be an authorized agent or employee of Erie Thames.

A customer, who believes that he has suffered damages to his property or equipment as a result of negligence on the part of Erie Thames, may submit a written claim for damages to Erie Thames. Erie Thames will investigate the claim and respond in writing within 10 business days of the receipt of the claim.

1.7 Distributor Rights

In those instances where the Customer has the authority to hire a Contractor to construct plant which will become part of Erie Thames' system, Erie Thames shall have the right to require the Contractor to submit proof of previous experience and satisfactory performance, and, Erie Thames shall have the right to investigate such proof and approve the Contractor prior to the Owner awarding a contract for the work to the Contractor.

Erie Thames shall have access to Customer property in accordance with section 40 of the *Electricity Act, 1998.*

1.8 Disputes

If, following good faith negotiations between a customer or other market participant and Erie Thames, a resolution cannot be reached, the dispute may be submitted to a dispute resolution process.

Any dispute which shall arise between Erie Thames and a customer(s) and other market participants subject to the terms of these Conditions of Service concerning the rights, duties or obligations of Erie Thames or others subject to these Conditions of Service, shall be subject to the following dispute resolution procedure:

Mediation

- Either party (the “Initiating Party”) may invoke the dispute resolution procedure by sending a written notice to the other party (the “Respondent Party”) describing the nature of the dispute and designating a representative of the Initiating Party with appropriate authority to be its representative in negotiations relating to the dispute. The responding Party shall, within five business days of the receipt of such notice, send a written notice to the Initiating Party, designating a representative of the Responding party with the appropriate authority to be its representative in negotiations relating to the dispute.

- Within ten business days of the receipt by the Initiating Party of the written notice of the Responding Party the designated representatives shall enter into good faith negotiations with a view to resolving the dispute. If the dispute is not resolved in thirty days of the commencement of such negotiations, or such longer period as may be agreed upon, either party may, by written notice to the other party, require that the parties be assisted in their negotiations by a mediator. The mediator shall be acceptable to both parties and have knowledge and experience in the matter under dispute, or professional qualifications, or experience in alternative dispute resolution, or both. The parties shall thereafter participate in mediation with the mediator through such process as the mediator, in consultation with the parties, may determine.

- None of the parties shall be deemed to be in default of any matter being mediated, until effective or after the date mediation fails.

Referral to Dispute Resolution

Any dispute that is not resolved through mediation as described above shall be referred to the Ontario Energy Board dispute resolution agency according to the following procedure:

- Upon the written demand of either of the parties, the dispute shall be referred to the disputes resolution agency that has been appointed by the Ontario Energy Board.

SECTION 2 DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections

This section includes information that is applicable to all customer classes of Erie Thames. Items that are applicable to only a specific customer class are covered in Section 3.

2.1.1 Building that Lies Along

As provided in Section 28 of the *Electricity Act 1998* Erie Thames has the Obligation to connect any Building that 'lies along" its distribution system. A building 'lies along" a distribution line if it can be connected to Erie Thames's distribution system, and meets the conditions listed in the Conditions of Service of Erie Thames who owns or operates the distribution line.

A Building that 'lies along" a distribution line may be refused connection to that line should the connection have an adverse effect on the reliability or safety of the distribution system.

2.1.2 Expansions / Offer to Connect

Under the terms of the Distribution System Code Section 3.1, a Distributor has the Obligation to make an Offer to Connect any Building that 'lies along" its distribution system. Erie Thames may refuse to connect a customer for the reason described in subsection 2.1.3 of Erie Thames Conditions of Service. The Offer to Connect must be fair and reasonable and be based on Erie Thames design standard. The Offer to Connect must also be made within a reasonable time from the request for connection.

Erie Thames may require a customer to pay all or a part of the costs of electrical plant installed to supply only that customer. Such capital contributions will be calculated using the guidelines set out by the OEB in the Distribution System Code.

2.1.3 Connection Denial

The Distribution System Code in section 3.1 sets outs the conditions for a Distributor to deny connections. A Distributor is not obligated to connect a building within its service territory if the connection would result in any of the following:

- Contravention of existing Canadian Laws, and those of the Province of Ontario.
- Violations of conditions in a Distributors' Licence.
- Materially adverse effect on the reliability or safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of Erie Thames's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection.
- If the person requesting the connection owes Erie Thames money for distribution services, or for non-payment of a security deposit. Erie Thames shall give the person a reasonable opportunity to

provide the security deposit consistent with Section 2.4.20 of the Distribution System Code.

2.1.4 Inspections Before Connections

Erie Thames has the right to request an inspection prior to any connection.

All customer electrical installations shall be inspected and approved by the Electrical Safety Authority, referred to herein as the ESA.

Erie Thames requires notification from the ESA of this approval prior to the connection of a customer's service.

Services that have been disconnected for a period of six months or longer shall also be re-inspected and approved by the ESA prior to reconnection.

Temporary services, for construction purposes, are approved by the ESA for a period of twelve months and must be re-inspected should the period of use exceed twelve months.

Erie Thames reserves the right to inspect and approve Transformer rooms, Vaults and Pads prior to during and following the installation of equipment.

Provision for metering shall be inspected and approved by Erie Thames prior to connection.

Customer owned substations must be inspected by both the Electrical Safety Authority and Erie Thames, prior to connection to the Distribution system.

Duct banks and road crossings shall be inspected and approved by Erie Thames prior to the pouring of concrete and again before backfilling.

Erie Thames reserves the right to inspect any underground trenches prior to backfilling.

Erie Thames reserves the right to approve the installation and location of all submarine cable. All documentation and permits required for laying of submarine cable must be provided to Erie Thames. The installation of submarine cable must meet the requirements of all governing legislation.

All work done on existing Distributor plant must be authorized by Erie Thames and carried out in accordance with all applicable safety acts and regulations.

In accordance with the Distribution System Code, if Erie Thames refuses to connect a building in its service territory that lies along one of its distribution lines, Erie Thames shall inform the person requesting the connection of the reasons for not connecting, and where Erie Thames is able to provide a remedy, make an offer to connect. If Erie Thames is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection can be made.

2.1.5 Relocation of Plant

Erie Thames will, where feasible, accommodate requests to relocate electrical plant such as poles and metal enclosed equipment.

The customer will be required to pay all of the costs incurred by the relocation.

Requests by civic authorities to relocate distribution facilities will be done so in accordance with the appropriate regulations.

2.1.6 Easements

To maintain the reliability, integrity and efficiency of the distribution system, Erie Thames has the right to have supply facilities on private property registered against title to the property. Easements are required whenever Erie Thames underground or overhead plant is to be located on private property or crosses over an adjacent private property to service a Customer.

The Customer shall acquire and grant in Erie Thames name, at no cost to Erie Thames, where required, an easement to permit installation and maintenance of service. The width and extent of this easement shall be determined by Erie Thames. The easement shall be granted prior to connection of the service.

The Owner shall furnish to Erie Thames, free and clear of all encumbrances, sufficient easements to enable the servicing of all existing or proposed developments or subdivisions from plants located on the Owners' property.

Sufficient property at suitable locations shall be made available for the purpose of the installation of distributors' assets.

The Customer will prepare at its own costs a reference plan and associated easement documents to the satisfaction of Erie Thames solicitor prior to its registration and register the easement plan. Details will be provided upon application for service.

Where surface restoration by Erie Thames is required following any repairs or maintenance to a service, Erie Thames will in so far as is practicable, restore the property to its original condition; and provide compensation for any damages caused by the entry that cannot be repaired.

2.1.7 Contracts

Standard Form of Contract - Connection to the electrical distribution system will be provided upon completion of a signed contract between the customer and Erie Thames, and receipt of approval by the Electrical Safety Authority ("ESA").

All customers will be required to complete and sign the standard form of contract to apply for the supply of an electrical energy connection. A Standard Contract for service shall be considered as being in force from the date it is signed by the Customer and Erie Thames and shall remain in force until terminated by either party.

Implied Contract - In all cases, notwithstanding the absence of a formal contract, the taking and using of electrical energy from Erie Thames by any Person or Persons constitutes the acceptance of the terms and conditions of all regulations, conditions and rates as established by Erie Thames. Such acceptance and use of energy shall be deemed to be the acceptance of a binding contract with Erie Thames and the Person so accepting shall be liable for payment for such energy and the contract shall be binding upon the Person's heirs, administrators, executors, successors or assigns.

Special Contracts - Special contracts that are customized in accordance with the service requested by the Customer normally include, but are not necessarily limited to, the following examples:

- *construction sites*

- *mobile facilities*
- *non-permanent structures*
- *special occasions, etc.*
- *Generation*

Opening and Closing of Accounts – A property owner or occupant shall contact Erie Thames by telephone to make a request to open an account with Erie Thames. This will establish a contract with Erie Thames and the Customer's acceptance of all responsibilities related to electricity charges applicable to the account. A Solicitor or person with Power of Attorney can agree on behalf of the Customer to the opening of an account.

Erie Thames shall open and or close an account for a property in the name of a person at the request of a third party consistent to Section 2.8 of the Distribution System Code and as outlined in Appendix 3 of these Conditions of Service, Policy 5.0 Opening and Closing of Accounts.

Erie Thames may require a security deposit consistent with Section 2.4.9 of the Distribution System Code and as outlined in Appendix 3 of these Conditions of Service, Policy 6.1 Security Deposits.

Customers requesting to close an account are required to provide reasonable notice to allow time to read the meter at the service address and issue a final bill. If a Customer requests to cancel a service agreement and no longer request electricity to be provided to the service address, Erie Thames may disconnect the electricity service. If a request is made for reconnection the new Customer setting up an account at the service address will incur the applicable costs to reconnect the service. If the electricity service has been disconnected from a premise for six months or longer, an ESA inspection is required.

In all cases, Erie Thames will not maintain availability of a meter and service without an active account and Customer. When a Customer advises Erie Thames they are no longer responsible for the account or requests to close an account, a final bill will be issued for the account. If, at that time, a new Customer has not assumed responsibility for services provided to the property, Erie Thames may disconnect the property.

Landlord and Tenant Agreement – When a tenant has opened an account at a property for the distribution of services they have agreed to be an Erie Thames Customer and have accepted responsibility for electricity charges provided to the service address. Therefore, the contract is with that tenant. When a tenant closes the account, Erie Thames will adhere to the date provided by the tenant, regardless of any agreements between the tenant and the landlord or owner, and a final bill will be issued for the account. Erie Thames shall not seek to recover any charges for service provided to that tenant at the rental unit after closure of the account from any person including the landlord/owner unless the person has agreed to assume responsibility for the charges.
Erie Thames may enter into an agreement with a landlord or owner whereby the landlord/owner agrees to assume responsibility for paying for continued service to the rental property after closure of a tenants account.

A landlord or owner may enter into the above mentioned agreement either by telephone or by written confirmation delivered by mail or email. A new account will be set up in the landlord/owner's, name pursuant to such an agreement, when:

- Erie Thames is advised that the tenant is vacating the property;
- the landlord/owner will be responsible for the new account(s) and any electricity charges for service provided at any and all units listed at a service address; and
- a new account set up charge will apply to new account(s), which will appear on the first

electricity bill issued.

It is the responsibility of the landlord to ensure that Erie Thames is made aware of any changes in contact, mailing and/or billing information. Where landlord information is not known, the above agreement will not apply and Erie Thames may disconnection of the service.

2.2 Disconnection and Use of Load Control Devices

Erie Thames has the right and/or obligation to disconnect or limit the supply of electrical energy to a Customer consistent with the *Electricity Act* for causes including but not limited to:

- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of Erie Thames's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection.
- Inability of Erie Thames to perform planned inspections and maintenance.
- Failure of the consumer or customer to comply with a directive of a distributor that Erie Thames makes for purposes of meeting its licence obligations.
- The customer owes Erie Thames money for distribution services, or for a security deposit. Erie Thames shall give the customer a reasonable opportunity to provide the security deposit consistent with Section 2.4.20 and 2.4.20Aof the Distribution System Code.
- Failure to notify Erie Thames of Customer responsibility for electricity account when a new party moves into an existing connected property and consumes electricity;

Without limiting the generality of the foregoing, prior to disconnecting a property for non-payment, Erie Thames shall provide to any person that receives notice of disconnection:

- The Fire Safety Notice of the Office of the Fire Marshal; and
- Any other public safety notices or information bulletins issued by public safety authorities provided to Erie Thames.

Appendix 3 of these Conditions of Service includes Erie Thames Disconnection Policy and Use of Load Control Devices Policy. The Policies describe Erie Thames disconnection and the use of load control devices practices.

Disconnection does not relieve the Customer of the responsibility to pay the overdue amounts. Erie Thames may recover from the Customer responsible for the disconnection reasonable costs associated with disconnection including costs for repairs of Erie Thames physical assets attached to the property in reconnecting the property.

Reconnection or restoration of the electricity service will occur only after the reason for disconnection or limitation has been remedied. Erie Thames may recover from the person requesting the reconnection any Erie Thames OEB approved reconnection charge.

2.3 Conveyance of Electricity

2.3.1 Guaranty of Supply

Erie Thames agrees to use reasonable diligence in providing a regular and uninterrupted supply but does not guarantee a constant supply or the maintenance of unvaried frequency or voltage and will not be liable in damages to the Customer by reason of any failure in respect thereof.

Customers requiring a higher degree of security than that of normal supply are responsible to provide their own back-up or standby facilities.

When power is interrupted, or the Customer is experiencing power quality problems the Customer or their electrical contractor shall first ensure that interruption is not due to problems within the customer owned installation. If after verifying that the cause of the problem does not reside on the customers' installation, the customer shall contact Erie Thames. Erie Thames will respond to and take reasonable steps to restore power. Erie Thames reserves the right to recover costs from the customer for making false claims of interruptions.

Although it is Erie Thames policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customers' supply to maintain or improve Erie Thames system, or to provide new or upgraded services to other Customers. Whenever practical and cost effective, as determined by Erie Thames, arrangements suitable to the Customer and Erie Thames may be made to minimize any inconvenience. Erie Thames will endeavor to provide the Customer with reasonable advance notice, except in cases of emergency, involving danger to life and limb, or impending severe equipment damage.

Erie Thames will endeavor to notify Customers prior to interrupting the supply to any individual service. However, if an unsafe or hazardous condition is found to exist, or if the use of electricity by apparatus, appliances, or other equipment is found to be unsafe or damaging to Erie Thames or the public, service may be discontinued without notice.

Depending on the outage duration and the number of Customers affected, Erie Thames may issue a news release to advise the general public of the outage.

2.3.2 Power Quality

Erie Thames will respond to and take reasonable steps to investigate consumer power quality complaints and report to the consumer on the results of the investigation. The method and level of investigation will be at the discretion of Erie Thames.

If the source of a power quality problem is caused by the consumer making the complaint, Erie Thames may seek reimbursement for the time and cost spent to investigate the complaint.

If the source of a power quality problem is caused by a consumer, Erie Thames may direct the consumer to take corrective action. If the Consumer does not take such action within a reasonable time, Erie Thames may disconnect the supply of power to the Customer. (*see section 2.2*)

2.3.3 Electrical Disturbances

There are levels of voltage fluctuation and other disturbances that can cause flickering lights and more serious difficulties for Customers connected to Erie Thames distribution system.

Some types of electronic equipment, such as video display terminals, can be affected by the close proximity of high electrical currents that may be present in transformer rooms.

No electrical equipment, which may produce an undesirable system disturbance, shall be connected by a customer to a customer's service without prior approval of Erie Thames.
Examples of equipment, which may cause disturbance, are large motors, welders and variable speed drives. In planning the installation of such equipment, the customer is required to consult with Erie Thames.

Erie Thames will endeavour to maintain voltage variation limits, under normal operating conditions, at the Customers' Delivery Points, as specified by the latest edition of the Canadian Standards Association, C235. However, more sensitive electronic equipment such as computers can be seriously affected by variations in quality of supply voltage. Customers who need electrical power of high quality and with rigid voltage tolerances are responsible for providing their own power conditioning equipment.

Customers requiring a three-phase supply should install protective apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of Erie Thames supply.

The customer shall provide such protective devices as may be necessary to protect his property or equipment from any disturbance beyond the control of Erie Thames.

2.3.4 Standard Voltage Offerings

2.3.4.1 For Secondary Voltage

The Supply Voltage governs the limit of supply capacity for any Customer. General guidelines for supply <u>from overhead street circuits are as follows</u>:

- *at 120/240 V. single phase, or*
- *347/600 V. three phase, four wire, or*
- *120/208 V three phase, four wire,*

OR

Where street circuits are buried, the Supply Voltage and limits will be determined upon application to Erie Thames.

OR

Where the Customer or Developer provides a pad on private property;

- *at 120/240 V single phase, or*
- *at 120/208 V three phase, four wire, or*
- *at 347/600 V three-phase, four-wire*

2.3.4.2 For Primary Voltage

Primary supplies to transformers or customer-owned substations will be one of the following as determined by Erie Thames:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*

- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *27,600 volts 3 phase 3 wire delta*
- *44,000 volts 3 phase 3 wire*

An electrical requirement in excess of 750 kVA may require a customer owned Substation supplied at the voltage as determined by Erie Thames.

2.3.5 Voltage Guidelines

Erie Thames maintains service voltage at the Customers' service entrance within the guidelines of C.S.A. Standard CAN3-C235 (latest edition) which allows variations from nominal voltage of:

6% for Normal Operating Conditions
8% for Extreme Operating Conditions

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on a planned and programmed basis, but not necessarily on an emergency basis.

Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to voltage levels and duration, etc.

2.3.6 Back-up Generators

Customers with portable or permanently connected emergency generation capability shall comply with all applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that customer emergency generation does not back-feed on Erie Thames system.

Customers with permanently connected emergency generation equipment shall notify Erie Thames regarding the presence of such equipment.

Erie Thames reserves the right to have the connection of this equipment inspected.

Generation systems found to be feeding into the Distribution system without proper approval of Erie Thames shall be subject to immediate disconnection.

2.3.7 Metering

2.3.7.1 General

2.3.7.1.1 Access

Erie Thames or its agents shall have the right to access and read any of Erie Thames electricity meters on the Customer's premises.

All metering installations shall be accessible from a public area.

2.3.7.1.2 Costs

All Erie Thames metering equipment located on the Customer's premises are in the care and at the risk of the Customer and if destroyed or damaged, other than by normal usage, the Customer will pay for the cost of repair or replacement.

Regardless of any charges for metering installations, all meters and meter instrumentation equipment shall remain the property of Erie Thames and maintenance of this equipment shall be Erie Thames responsibility.

2.3.7.1.3 Voltage

Generally, metering will be at utilization voltage. Where Erie Thames provides primary transformation, primary voltage metering will be allowed only in special circumstances following full discussion with Erie Thames.

Customer-owned substations may require primary metering. The provisions required for these installations shall be specified and approved by Erie Thames for each application.

2.3.7.1.4 Primary / Bulk Metering

Primary metering units may be installed outdoors or within and electrical vault as outlined in the current Electrical Safety Code. Where the Owner prefers not to provide an approved electrical vault, Erie Thames at additional cost can provide a metering unit with non-flammable coolant.

Non-residential or mixed-use buildings will normally be bulk metered by a single meter. However, where specific areas are clearly and permanently defined and in other respects as a separate entity, individual metering of the loads will be considered.

In all installations where the Customer requests revenue metering remote from the secondary entrance equipment or downstream from a Customer-owned dry-core transformer, provisions are required for a bulk meter directly after the main switch. This bulk metering is required in addition to any public metering provisions. The Customer will be required to contribute to the cost of the metering installation.

Where more than one meter exists, the meters shall be grouped where practicable.

The customer/contractor shall permanently and legibly identify all metered services with respect to correct municipal 911 address and unit #. The identification shall be applied to all service switches and breakers and to all meter cabinets and meter mounting devices that are not immediately adjacent to the service switch. The customer/contractor shall insure that all service identifications are accurate and by not doing so will be held totally responsible. Erie Thames shall issue a Meter Verification Sheet for this purpose to the owner or contractor.

In any case, a copy of the metering layout plan shall be forwarded to Erie Thames for review and approval.

If the distribution of the metered load circuit is in dispute, (ie: circuits from one premise is found to supply a second premise) Erie Thames reserves the right to transfer all accounts into the Property Owners' name until such time as the problem has been resolved, and the individual metering can be clearly identified with the individual units.

2.3.7.1.5 Locks

All devices on the line side of Erie Thames metering shall have provisions for padlocking.

For commercial and industrial services the Customer's main switch shall have provisions for padlocking the switch handle in the open position and the switch cover or door in the closed position.

When a disconnect device has been locked in the “OFF” position by Erie Thames, under no circumstances shall anyone remove the lock and energize it without first receiving approval from Erie Thames.

At the discretion of Erie Thames, a dual locking arrangement, a master key arrangement, a key box arrangement, or a copy of the access key will be required for access.

2.3.7.2 Current Transformer Boxes

Where a current transformer box is required, it shall be CSA approved, of a size and type as stipulated by Erie Thames, and include a provision for padlocks. A removable plate shall be provided in the box for mounting the equipment.

As an alternative to a separate CT box and meter, a single enclosure combining both functions may be feasible. Contact Erie Thames for details.

In cases where the CTs only meter a portion of the metal clad switchgear (such as house loads), a separate disconnect switch must be installed ahead of the metering compartment so that the service can be de-energized without any interruption to the main service supply.

Generally, one house load meter only will be allowed. Additional house load meters will require authorization from Erie Thames.

Conductors should enter the current transformer box at the top and leave at the bottom, or vice versa. If this cannot be arranged, the next largest CT box must be used to enable conductors to be trained in place. Where parallel conductors are used, the sum of the conductors will determine the size of the CT box to use. In all cases the Customer shall supply suitable cable termination lugs.

On all electrical services that require current transformers and the neutral for metering, an isolated neutral block shall be provided in the current transformer box.

2.3.7.3 Interval Metering

The Distribution System Code, as amended from time to time, requires Erie Thames to meter Customers of specific load levels with pulse-recording meters, or interval meters, which are interrogated remotely. Erie Thames, at its’ sole discretion, may also require such metering on any customer whose load characteristics may have a significant impact on the Net System Load Shape, or where reasonable access to the meter for the purpose of acquiring metering data may be limited due to location.

A customer that requests interval metering shall compensate a distributor for all incremental costs associated with that meter, including the capital cost of the interval meter, installation costs associated with the interval meter, ongoing maintenance (including allowance for meter failure), verification and re-verification of the meter, installation and ongoing provision of communication line or communication link with the customer' s meter, and cost of metering made redundant by the customer requesting interval metering. The communication system utilized for interval meters shall be in accordance with Erie Thames requirements.

Where such metering exists Erie Thames will consider customer requests to provide a secondary pulse for load control or customer-owned metering at the customers' expense.

Where a customer submits a request to read their own interval meter, Erie Thames shall make this access available given the following conditions are met:

- The meter has the capability of read-only password protection
- The customer provides a signed copy of the "Interval Metering Access Agreement" to Erie Thames.

2.3.7.3.1 Interval Metering Communications

- Solid-state recorders and/or Electronic Interval Meters installed by Erie Thames have provision for remote interrogation over a telephone line. To accommodate this feature the Owner will provide shared access to a telephone line for Erie Thames metering purposes.
- At its' sole discretion, for metering installations where loss of metering data would cause a substantial impact on Erie Thames Settlement System, Erie Thames may require the phone line to be dedicated for metering purposes only.
- A voice quality telephone line, which is active 24 hours a day to the metering location extension jack, which is mounted on the metering board.
- Phone lines must be installed and functioning prior to the new service being energized.

2.3.7.3.2 Smart Metering

Erie Thames is replacing all its residential and small commercial meters with Smart Meters to comply with the government's smart meter initiatives. With implementation of time-of-use pricing, the processes for meter consumption data retrieval and billing will align with applicable regulations and directions from the Smart Meter Entity.

2.3.7.4 Meter Reading

Erie Thames will read all meters on a regularly scheduled basis whenever possible. If an actual meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

2.3.7.5 Final Meter Reading

When a service is no longer required, or the Customer is switching Energy Providers, the Customer shall provide Erie Thames sufficient notice of the date so that a final meter reading can be obtained. The Customer shall provide access to Erie Thames or its agents for this purpose.

If a final meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

2.3.7.6 Faulty Registration of Meters

Metering electricity usage for the purpose of billing is governed by the Federal Electricity and Gas Inspection Act and associated regulations, under the jurisdiction of Measurement Canada, Industry Canada. Erie Thames revenue meters are required to comply with the accuracy specifications established by the regulations under the above Act.

In the event of incorrect electricity usage registration, Erie Thames will determine the correction factors based on the specific cause of the metering error and the Customer's electricity usage history. The Customer shall pay for all the energy supplied, a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises by Erie Thames, due regard being given to any change in the character of the installation and/or the demand.

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill calculation, the correction will apply for the period defined in the Retail Settlement Code, Section 7.7. Erie Thames will correct the bills for that period in accordance with the regulations under the Electricity and Gas Inspection Act (Canada).

2.3.7.7 Meter Dispute Testing

Erie Thames will attempt to resolve billing enquiries. However, to give Customers confidence in the accuracy of electricity meters, Erie Thames will conduct an internal investigation to verify the accuracy of any meter the Customer believes to be recording incorrectly. If the internal investigation does not resolve the matter, the Customer or Erie Thames may request Measurement Canada to test the meter.

If the test indicates that the meter is not accurate, the Customer's historic billing will be adjusted, and Erie Thames shall pay the full costs of the meter dispute testing.

2.3.7.8 Location

The location of the indoor or outdoor meter shall be readily accessible at all times and acceptable to Erie Thames. If a meter is recessed or enclosed after installation, without the prior approval of Erie Thames, the service may be subject to disconnection.

The location of the service entrance, routing of duct banks, metering, and all other works will be established through consultation with Erie Thames. Failure to comply may result in relocation of the service plant at the Owner's expense.

In all locations where Commercial/Industrial revenue metering is accessible to the general public, a lockable enclosure or a room for service equipment and meters, shall be provided by the Owner at the discretion of Erie Thames, as follows:

- *An electrical room reserved solely for metering equipment or*
- *Metal enclosed switchgear approved by Erie Thames or*
- *A suitable metal metering cabinet or*
- *A vandal proof cage.*

2.3.7.9 Meter Mounting Heights

Provision for metering shall facilitate a practical mounting height for revenue meters in compliance with all applicable codes and regulations.

2.3.7.10 Environment

The following requirements apply to the areas allocated for revenue metering.

The customer to the satisfaction of Erie Thames shall provide where there is the possibility of danger to workmen, or damage to equipment from moving machinery, dust, fumes, or moisture, protective arrangements.

A clear safe working space of not less than 1.2 m (48") in front of the installation from the floor to ceiling with a minimum ceiling height of 2.1 m (84") provided to insure the safety of Erie Thames or other authorized employee(s) who may be required to work on the installation.

Where excessive vibration may affect or damage metering equipment, adequate shock-absorbing mounting shall be provided and installed by the customer.

2.3.7.11 Meter Sockets

The owner will supply and install a meter socket as specified by Erie Thames. Meter sockets will be directly accessible to Erie Thames staff.

A listing of approved revenue metering sockets is available from Erie Thames.

2.3.7.12 Cabinets

Where required by these Conditions of Service the Owner shall supply and install a meter cabinet to Erie Thames requirements.

Meter cabinets shall be installed indoors, except where special permission is granted by Erie Thames to install the meter cabinet outside. In such cases, an approved weather proof, lockable, C.S.A. approved meter cabinet shall be provided by the Customer.

2.3.7.13 Metering Loops

Three-phase, four-wire services will require a loop for metering, within the meter cabinet, for all three phases.

Mineral insulated, solid, or hard drawn wire conductors are not acceptable as metering loops.

2.3.7.14 Metal Enclosed Switchgear

The following regulations apply to the installation of instrument transformers and metering equipment within metal enclosed switchgear.

Erie Thames will provide the following revenue metering equipment as required:

- Colour coded secondary wiring

- Revenue meters

The Owner shall:

- consult with Erie Thames regarding the metering equipment to be provided which may include:

    - Potential transformers
    - Potential transformer fuse holders and fuses
    - Current transformers
    - Phone line for remote interrogation of meters
    - Duplicate Pulse Initiators
    - Provide complete shipping instructions for instrument transformers for those projects where these are to be provided by Erie Thames for installation by the switchboard manufacturer.
    - Install instrument transformers, metering cabinet and conduit.
    - Each main bus bar to be drilled and tapped (10-32) or (10-24) on the line side of the removable current transformer link.

- Submit two copies of the manufacturer's switchboard drawings, for approval, dimensioned to show provision for and arrangement of Erie Thames metering equipment.

Meters shall be installed by Erie Thames in a customer-owned metal cabinet of a size and type pre-approved by Erie Thames, mounted at an approved location separate from the switchgear.

Tamper proof or sealable rigid conduit or any equally approved conduit of a size and type specified by Erie Thames shall be installed between the CT compartment of the switchgear and the meter cabinet.

For conduit installations greater than 30 m (100'), in length or where several bends are necessary, larger conduits or other special provision may be required, at the discretion of Erie Thames.

2.3.7.15 Switchgear Connected to Wye Source

Where a Wye source neutral connection is to be used or grounded, the Owner shall provide a conductor sized to the requirements of the Ontario Electrical Safety Code from the instrument transformer compartment to the neutral connection.

2.3.7.16 Four Quadrant Metering (Generation)

All Ontario Energy Board-licensed generators connected to the distribution system that sell energy and settle through Erie Thames's retail settlement process shall be required to install metering that meets the requirements of the Distribution System Code as approved by the Ontario Energy Board, and/or the Market Rules as approved by the Independent Electricity Market Operator.

2.4 Tariffs and Charges

2.4.1 Service Connection

Charges for Service Connections are set out in Erie Thames approved rates, (Miscellaneous Rates and Charges) and may be obtained by request from Erie Thames. Notice of Rate revisions may be published in the local newspapers, on Erie Thames website and/or mailed out to all customers with the first billing issued at revised rates.

2.4.2 Energy Supply

Erie Thames shall provide Customers connected to the Distribution System with access to electricity through Standard Supply Service as defined in the Retail Settlement Code published by the OEB or as mandated though Legislation or Regulations issued by the Ministry of Energy.

Disputes arising from charges relating to Standard Supply Service shall be directed to Erie Thames.

Customers will be switched to their Retailer of choice only if the retailer has a Service Agreement with Erie Thames. The Customer's authorized Retailer through the Electronic Business Transaction system (EBT) must make the Service Transfer Request (STR) in accordance with the rules established and amended from time to time by the Ontario Energy Board.

Disputes arising from charges relating to Retailer Service shall be directed to the Retailer.

Erie Thames may, at its discretion, refuse to process a Service Transfer Request for a Customer to switch to a Retailer if that Customer owes money to Erie Thames for Distribution Services and or Standard Supply Service.

2.4.2.1 Wheeling of Power

Customers considering delivery of electricity through Erie Thames Distribution System shall contact Erie Thames for technical requirements and current applicable Rates.

2.4.3 Deposits

Whenever required by Erie Thames, the Customer shall provide and maintain security in an amount that Erie Thames has been mandated to collect, or deems necessary and reasonable. Erie Thames shall require security amounts based on Erie Thames existing Security Deposit Policies. The current Security Deposit policy is included as Appendix 3 – Policy 6.1 of these Conditions of Service.

Effective October 1, 2011, Erie Thames will waive the requirement to provide a security deposit for Eligible Low-Income Customer provided the Customer contacts Erie Thames to request such a waiver and their low-income eligibility is confirmed. Furthermore, where a social service agency or a government agency advises Erie Thames that it is assessing a Customer for eligibility as an Eligible Low-Income Customer, the due date for payment of the security deposit shall be extended for 21 days pending the eligibility decision. Additionally, an Eligible Low-Income Customer may, after October 1, 2011, request a refund of any security deposit previously paid to Erie Thames, after application of the security deposit to any outstanding arrears on said customer's account. The criteria for waiving and/or returning a security deposit are defined in Appendix 3 – Policy 6.1 Security Deposit of these Conditions of Service.

Where a customer proposes the development of premises that requires Erie Thames to place equipment orders for special projects, the customer is required to sign the necessary Supply Agreements and furnish a suitable deposit before such equipment is ordered by Erie Thames.

2.4.4 Billing

Erie Thames may, at its option, render bills to its Customers on either a monthly, bi-monthly, quarterly or annual basis. The option applicable to the customer shall be identified to the customer at the time of application for service.

Prorating of Service and Demand charges will be performed at the discretion of Erie Thames.

2.4.4.1 Competitive Charges:

Are based on rates as determined by:

i. the Hourly Ontario Spot Market Price (HOEP); or
ii. the utilities Weighted Average Price (WAP) as determined by net system load; or
iii. the customers retailer contract rate; or
iv. the rates published by the OEB; or
v. Legislation or Regulations issued by the Ministry of Energy.

2.4.4.2 Non-competitive Charges:

Non-competitive charges are based on rates approved by the Ontario Energy Board and fall outside the scope of this document. Approved rates as they relate to the transmission, distribution and other non-competitive elements may be attained through the utilities rate documents. These documents will be provided by the utility at the customer’s request.

2.4.4.3 Billable Engineering Units:

Customers will be billed on:

i. actual or estimated meter reading data; or
ii. derived consumption data (Streetlights, sentinel lights and other scattered loads); or
iii. a flat rate, depending on the type of load being billed.

2.4.4.4 Use of Estimates:

In months where a bill is issued, but no reading is obtained, Erie Thames estimates usage in order to determine billing quantities. The estimate is based on historical usage for the premise, or a pre-determined quantity if there is no historical usage information available.

2.4.5 Payments and Late Payment Charges

Bills are rendered for distribution services and electrical energy used by the Customer. Bills are payable in full by the due date.

Bills are due when rendered by the utility. A customer may pay the bill without the application of a late payment charge up to a due date, which shall be a minimum of sixteen calendar days from the date of mailing or hand delivery of the bill. This due date shall be identified clearly on the customer’s bill.

Where payment is made by mail, payment will be deemed to be made on the date post-marked. Where payment is made at a financial institution acceptable to the utility, payment will be deemed to be made when stamped/acknowledged by the financial institution or an equivalent transaction record is made.

A partial payment will be applied to any outstanding arrears before being applied to the current billing, unless special considerations have been made by the utility.

Outstanding bills are subject to the collection process and may ultimately lead to the service being discontinued or limited. Service will be restored once satisfactory payment has been made. Discontinuance of service does not relieve the Customer of the liability for arrears.

Erie Thames shall not be liable for any damage on the Customer's premises resulting from such discontinuance of service. A reconnection charge may apply where the service has been disconnected due to non-payment.

The Customer will be required to pay additional charges for the processing of non-sufficient fund (N.S.F.) cheques.

2.4.6 Unauthorized Energy Use

Erie Thames shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, Erie Thames shall notify, if appropriate, Measurement Canada, The Electrical Safety Authority, Police Officials, Retailers that service customers affected by an authorized energy use, or other entities.

Erie Thames may recover from the parties responsible for the unauthorized energy use all costs incurred by Erie Thames arising from unauthorized energy use, including an estimate of the energy used, inspection and repair costs.

A service disconnected due to unauthorized use of energy shall not be reconnected until such time as all arrears resulting from the unauthorized use has been resolved to the satisfaction of Erie Thames.

Prior to reconnection, Erie Thames shall require proper authorization from applicable authorities.

2.5 Customer Information

Erie Thames reserves the right to request specific information from the customer in order to facilitate the normal operation of its business. Failure of a customer to supply such information may prevent the normal continuation of service.

The Retail Settlement Code as amended from time to time specifies the rights of customers and their retailers to access current and historical usage information and related data and the obligations of distributors in providing access to such information.

Under these requirements, Erie Thames shall upon authorization by a customer make the following information available to the Customer or the Retailer that provides electricity to a customer connected to Erie Thames distribution system:

- Erie Thames account number for the customer,
- Erie Thames meter number for the meter or meters located at the customer's service address
- The customer's service address,
- The date of the most recent meter reading,
- The date of the previous meter reading,
- Multiplied kilowatt-hours recorded at the time of the most recent meter reading,

- Multiplied kilowatt-hours recorded at the time of the previous meter reading,
- Multiplied kW for the billing period (if demand metered),
- Multiplied kVA for the billing period (if available),
- Usage (kWh's) for each hour during the billing period for interval-metered customers
- An indicator of the read type (e.g., distributor read, consumer read, distributor estimate, etc.)
- Average distribution loss factor for the billing period

This information will be provided to the Customer / Retailer upon request twice per year at no charge. Erie Thames may request a fee to recover costs for additional requests. A request is considered to be data delivered to a single address. Thus, a single request to send information to three locations is considered three requests.

Erie Thames acknowledges that no confidential information regarding its' customers shall be released to a third party without the expressed prior written consent of the customer unless the request is rightfully received from the third party requesting the information, or Erie Thames is legally required to disclose such information under the terms and in accordance with the Freedom of Information and Protection of Privacy Act, R.S.O. 1990, c. F.31.

SECTION 3 CUSTOMER SPECIFIC

3.1 Residential

This section refers to the supply of electrical energy to Customers residing in residential dwelling units.

3.1.1 General

Energy is generally supplied as single phase, 3-wire, 60-Hertz, having a nominal voltage of 120/240 Volts.

There shall be only one Delivery Point to a dwelling.

In circumstances where two existing services are installed to a dwelling, and one service is to be upgraded, the upgraded service will replace both of the existing services.

All new single-family homes will be required to install their primary and secondary service wires to the specifications contained within Erie Thames technical specification document.

Whether the method of supply will be overhead or underground will be at the discretion of Erie Thames. Erie Thames will adhere to any existing regulations subject to requirements of authorities.

Unless specifically documented otherwise to the Customer, where Erie Thames has taken ownership of such plant all services installed by Erie Thames or by an approved contractor using approved materials, will be maintained by Erie Thames.

3.1.2 Early Consultation

The Customer shall supply a completed Site Planning document and related information to Erie Thames well in advance of installation commencement. (see appendix) The information shall be supplied in a manner requested by Erie Thames at the time of the application.

3.1.3 Standard Connection Allowance

For the purposes of calculating customer connection fees, the Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service.

The basic connection for each customer shall include;

- **i.** supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and
- **ii.** up to 30 meters of overhead conductor or an equivalent credit for underground services.

In the case of an upgrade to an existing service, where the existing service is below the basic connection, the credit up to the basic connection will apply.

Secondary services exceeding the basic 30 meter length may require specific design approved by Erie Thames to ensure power quality.

3.1.4 Variable Connection Fees

Any requirements above the defined basic connection shall be subject to a variable connection charge to be calculated as the costs associated with the installation of connection assets above and beyond the basic connection. Erie Thames may recover this amount from a customer through a connection charge or equivalent payment.

3.1.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of Erie Thames.

The Customer must obtain a Demarcation Point Location from Erie Thames before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by Erie Thames includes repair and like-for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by Erie Thames.

3.1.5.1 Secondary Service Connections

The Point of Demarcation for residential services up to 400 amps is at the line side of the Meter Base for Underground services, and at the top of the stack for Overhead services, beyond which the customer bears full responsibility for installation and maintenance.

The Point of Demarcation for residential services over 400 amps is at the secondary side of the transformer.

For Secondary Services wholly owned and maintained by the Customer, the Demarcation Point is the secondary connection at the transformer or the service bus.

The Customer shall install, own, and maintain the secondary conductor under any of the following conditions:

(a) conductor terminations are inside the Customer's building;
(b) conductor is installed beyond the service entrance;
(c) conductor is connected to a Primary Service; or
(d) conductor is a non-standard installation.

3.1.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at Erie Thames's Distribution system.

3.1.6 Supply Voltage

(a) A Residential building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by Erie Thames. The Owner shall obtain prior approval from Erie Thames for the use of any specific voltage at any specific location.

3.1.7 Access

At Erie Thames discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in Erie Thames name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to Erie Thames at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.1.8 Metering

The owner will supply and install a meter socket complete with collar acceptable to Erie Thames. Meter sockets will be directly accessible to Erie Thames and:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact Erie Thames for specific location instructions prior to installation.

For more details refer to section 2.3.7 in these Conditions of Service.

3.1.9 Overhead Service

The Owner will provide service equipment to both Erie Thames and ESA requirements, and be of sufficient height to maintain proper minimum clearances. The Owner's main switch and the overhead service conductors will be of compatible capacity.

3.1.10 Underground Service

Underground secondary services will be installed at the Owners' expense, to Erie Thames's specifications. The Owner's main switch and the underground service conductors will be of compatible capacity.

3.1.11 Street Townhouses and Condominiums:

NOTE: Street Townhouses and Condominiums requiring centralized bulk metering will be covered under section 3.2 of these Conditions of Service. Also 3.1.11.2

3.1.11.1 Service Information:

The Owner will enter into a Servicing Agreement with Erie Thames, governing the terms and conditions under which the electrical distribution system and services will be designed and installed.

The Owner will provide all of the civil works to accommodate Erie Thames and will pay the complete cost of the electrical distribution system, design and services.

- The distribution system and services shall be underground unless otherwise approved.
- One service will be provided for each unit.
- The nominal service voltage will be 120/240 volts, 1 phase, 3 wire.
- Erie Thames will approve the location of duct banks, service routings and meter bases.
- Distribution plant shall not be installed until grade is at +/- 150 mm of final grade unless otherwise approved by Erie Thames.
- Street lighting will be to Municipal standards and installed at the Owner's expense.

3.1.11.2 Metering:

The Owner will supply and install meter sockets specified by Erie Thames.

Multiple or grouped meter bases will be accepted only when prior approval has been given by Erie Thames both as to type and proposed location. A completed meter verification form shall be provided to Erie Thames prior to energization.

Meter sockets will be located on the exterior front wall of the units and will be directly accessible to Erie Thames.

- Mounted on the front wall 1.7 metres above finished grade to the centre of the meter
- Installed ahead of (on the line side of) the main disconnect switch
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact Erie Thames for specific location instructions prior to installation.

Normally the service will not be energized until the outside finish in the area of the revenue meter has been completed. If exceptions are made to this, then the general contractor will be responsible for ensuring that the meter is suitably protected while work is being done on the exterior wall adjacent to the meter. The general contractor will be entirely responsible for all costs for materials and labour for repairing or replacing a damaged meter.

3.1.12 Seasonal and Remote Dwellings:

Due to the varied nature of Seasonal and Remote Dwellings some special arrangements may be required to service these locations. Arrangements will be made in such a manner to provide services such as restoring power, maintenance of equipment or new construction requests to water access or remote customers, without endangering personnel or the public.

3.1.12.1 Service Information

The Owner will enter into a Servicing Agreement with Erie Thames, governing the terms and conditions under which the electrical distribution system services will be provided.

In the event of a power interruption, Erie Thames will respond to and take reasonable steps to restore power. Erie Thames reserves the right to recover costs from the customer for making false claims of interruptions.

3.1.12.2 Access:

- **Night crossings**

  Erie Thames transportation equipment will not be used to cross any water ½ hour before sunset and ½ hour after sunrise due to safety concerns. It will be at the discretion of Erie Thames whether they will board customer owned transportation equipment in these circumstances.

- **Ice conditions**

  Recognizing seasonal ice hazards, Erie Thames reserves the right to suspend water passage during freeze up and spring thaw, as well as any such time deemed unsafe by Erie Thames.

- **Severe weather conditions**

  Recognizing that severe weather conditions may pose undue safety hazards, Erie Thames reserves the right to postpone attempts to restore power until restoration can be performed in a safe manner.

3.1.13 Inspection

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by Erie Thames prior to connection.

Erie Thames or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of Erie Thames and subject to inspection by Erie Thames.

(Refer to section 2.1.4 for further inspection details)

3.2 General Service (Below 50 kW)

3.2.1 General

This section 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 3.1.8 that require centralized bulk metering.

General Service buildings are defined as buildings that are used for purposes other than single-family dwellings.

3.2.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with Erie Thames in the early planning stages to ascertain Erie Thames requirements.

The Owner shall supply a completed Electrical Service Connection Form to Erie Thames well in advance of installation commencement to allow Erie Thames time for proper planning, ordering of equipment etc.

3.2.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Below 50 kW) shall be recovered through a variable connection Fee.

3.2.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. Erie Thames may recover this amount from a customer through a connection charge or equivalent payment.

3.2.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of Erie Thames.

The Customer must obtain a Demarcation Point Location from Erie Thames before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer’s expense.

Maintenance of the portion of the Secondary Service owned by Erie Thames includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by Erie Thames.

Erie Thames shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by Erie Thames will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner’s liability, maintenance and repair are at the Owners’ expense

3.2.5.1 Secondary Service Demarcations

A General Service Customer Demarcation Point is at the secondary side of the transformer, or as otherwise set by Erie Thames, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, Erie

Thames may establish the Demarcation Point at the top of stack for overhead services or at the meter base for underground services.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.2.5.2 Primary Service Demarcations

For Primary Service, the Demarcation Point is the primary connection at Erie Thames's Distribution system.

3.2.6 Supply Voltage

(a) A General Service building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by Erie Thames. The Owner shall obtain prior approval from Erie Thames for the use of any specific voltage at any specific location.

3.2.7 Access

At Erie Thames discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in Erie Thames name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to Erie Thames at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.2.8 Metering

The owner will supply and install a meter socket complete with collar acceptable to Erie Thames. Meter sockets will be directly accessible to Erie Thames and unless otherwise specified during the early consultation process:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact Erie Thames for specific location instructions prior to installation.

For more details refer to section 2.3.7 in these Conditions of Service.

3.2.9 Overhead Service

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, Erie Thames shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.2.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by Erie Thames.

3.2.11 Supply of Equipment

Erie Thames supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.2.12 Inspection

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by Erie Thames prior to connection.

Erie Thames or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of Erie Thames and subject to inspection by Erie Thames.

(Refer to section 2.1.4 for further inspection details)

3.3 General Service (Above 50 kW)

3.3.1 General

This section refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load greater than 50 kW.

3.3.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with Erie Thames in the early planning stages to ascertain Erie Thames requirements.

The Owner shall supply a completed Electrical Service Connection Form to Erie Thames well in advance of installation commencement to allow Erie Thames time for proper planning, ordering of equipment etc.

3.3.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 50 kW) shall be recovered through a variable connection Fee.

3.3.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. Erie Thames may recover this amount from a customer through a connection charge or equivalent payment.

3.3.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of Erie Thames.

The Customer must obtain a Demarcation Point Location from Erie Thames before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer’s expense.

Maintenance of the portion of the Secondary Service owned by Erie Thames includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by Erie Thames.

Erie Thames shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by Erie Thames will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner’s liability, maintenance and repair are at the Owners’ expense

3.3.5.1 Secondary Service Connections

A General Service Customer Demarcation Point for customers above 50 kW is at the secondary side of the transformer, or as otherwise set by Erie Thames, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, Erie Thames may establish the Delivery point at the top of stack for overhead services or at the meter base for underground services.

The location of the service entrance, routing of duct banks and all other works will be established through consultation with Erie Thames. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.3.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at Erie Thames's Distribution system.

In some circumstances the owner may be required to construct a private pole line. Primary conductors will be terminated complete with cut-out(s) at the Demarcation Point by Erie Thames at the owners' expense.

Where a private pole line is to be constructed by the Owner with an approved contractor, this shall be constructed to the ESA and Erie Thames requirements.

An electrical requirement in excess of 300 kVA may require a customer owned substation.

In some instances primary metering may be required.

3.3.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.
Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

Depending upon the location of the building Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by Erie Thames:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by Erie Thames. The Owner shall obtain prior approval from Erie Thames for the use of any specific voltage at any specific location.

3.3.7 Access

At Erie Thames discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in Erie Thames name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to Erie Thames at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.3.8 Metering

Meter installations will be directly accessible to Erie Thames. The owner will consult with Erie Thames well in advance of installation commencement to allow Erie Thames time for proper planning and ordering of equipment.

For more details refer to section 2.3.7 in these Conditions of Service.

3.3.9 Overhead Service

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, Erie Thames shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.3.10 Underground Service

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by Erie Thames.

3.3.11 Sub-transmission Service

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line. Erie Thames will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.3.12 Supply of Equipment

Erie Thames supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.3.13 Short Circuit Capacity

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.3.14 Inspection

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by Erie Thames prior to connection.

Erie Thames or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of Erie Thames and subject to inspection by Erie Thames.

(Refer to section 2.1.4 for further inspection details)

3.4 General Service (Above 500 kW)

3.4.1 General

This section refers to the supply of electrical energy to General Service Services requiring a connection at a connected load greater than 500 kW.

3.4.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with Erie Thames in the early planning stages to ascertain Erie Thames requirements.

The Customer shall supply a completed Electrical Service Connection Form to Erie Thames well in advance of installation commencement to allow Erie Thames time for proper planning, ordering of equipment etc.

Erie Thames will:

- *Advise the customer of the suitability of the in-service date*
- *Arrange with the customer for a Service Contract*
- *Review the submitted drawings; return one set to the customer with comments and/or approval. If requested by Erie Thames, the customer shall resubmit the drawings where the comments are extensive and require major changes*
- *Specify the required main fuse link or relay setting for co-ordination with the system. In case of multiple transformer stations, a complete co-ordination study shall be submitted by the customer for approval.*
- *Make the final connection to the source of supply*
- *Determine metering requirements*
- *Advise the Transmitter of the particulars of the customer owned substation*

3.4.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 500 kW) shall be recovered through a variable connection Fee.

3.4.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. Erie Thames may recover this amount from a customer through a connection charge or equivalent payment.

3.4.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of Erie Thames.

The Customer must obtain a Demarcation Point Location from Erie Thames before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer’s expense.

Maintenance of the portion of the Primary Service owned by Erie Thames includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by Erie Thames.

Erie Thames shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by Erie Thames will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

Erie Thames reserves the right to direct the operations of any customer owned switchgear connected to the distribution system including those located beyond the point of demarcation.

3.4.5.1 Service Installation

In General, the Demarcation Point for a General Service Customer with a demand of over 500 kW is on the primary side of the transformer at the first available distributor owned point of isolation, or as otherwise set by Erie Thames. This delivery point might be located on an adjacent property from which Erie Thames has an authorized easement. In all cases the final Demarcation Point will be the decision of Erie Thames.

The location of the service entrance, routing of duct banks, metering facilities, and all other works will be established through consultation with Erie Thames. Failure to comply may result in relocation of the service plant at the Owner's expense.

Erie Thames will install overhead supply lines and required cut-outs to the first point of support on private property. The location of this support must be approved by Erie Thames and shall be within 30 metres of Erie Thames existing overhead plant. All costs for materials and labour shall be at the customers' expense.

The service pole or first point of support on private property shall be considered self-supported and shall be complete with suitable hardware for attaching the suspension insulators. The Customer shall be responsible for all costs associated with equipment, installation, and inspection.

Where the customer wishes an underground supply, the customer shall supply and install the underground cables and termination pole complete with primary switch, fuses and lightning arresters. The installation shall be subject to ESA inspection and specific approval of Erie Thames. The customer owned termination pole must comply with items as prescribed by Erie Thames.

At Erie Thames discretion, the customers' underground service may be connected to a termination pole owned by Erie Thames. In such cases, Erie Thames shall supply and install at the customers expense, any required primary switch, fuses, and lightning arrestors.

When requested, the customer shall make provision in the substation switchgear or transformer, for loop feeding Erie Thames supply cables via load interrupter switches.

In some instances, primary metering may be required.

3.4.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.

General Service connections above 500 kW may require a customer owned substation.

Depending upon the location of the building, primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by Erie Thames:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by Erie Thames. The Owner shall obtain prior approval from Erie Thames for the use of any specific voltage at any specific location.

3.4.7 Access

At Erie Thames discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in Erie Thames name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to Erie Thames at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

Where the high voltage interrupting switches are located inside a building, a direct outside entrance to the switchgear room must be provided.

The outside door providing direct access to the transformer or switchgear room must be compliant with all applicable codes and requirements, and of a quality to be approved by Erie Thames.

3.4.8 Metering

The owner will supply and install provisions for metering following the details outlined both in these Conditions of Service, and technical documents provided to the customer during the consultation process.

For more details refer to section 2.3.7 in these Conditions of Service.

3.4.9 Sub-transmission Service

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line.

Erie Thames will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.4.10 Short Circuit Capacity

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.4.11 Drawings

Apart from the regular drawings submission to the ESA, the customer shall provide two sets of the following drawings and details to Erie Thames.

Survey Plan: prepared by an Ontario Land Surveyor, showing the property limits, registered plan and existing buildings or easements if any.

Site Plan: showing the location of the station relative to buildings, structures and set backs from adjacent property lines. The site plan shall also include the exact location of existing Distributor owned plant and the proposed route of the incoming supply.

Schematic or Single-Line Diagram: indicating the major components of the station and their electrical ratings. Where additions or alterations are being made, these shall be clearly distinguished from unchanged portions of the installation.

Electrical Details: sufficient details shall be provided in order to enable fast processing and approval of the station drawings. The following represents the minimum data required.

- Plan, elevation and profile views of the station structure, switchgear, transformer(s), termination poles, duct banks, etc.

- Dimensions to clearly indicate the electrical, physical and working clearances as well as relative location of all equipment.

- Pole or structure for dead-ending Erie Thames lines shall be complete with suitable hardware for attaching the suspension insulators that will be supplied and installed by Erie Thames.

- Fencing arrangement.

- Grounding details. (In the case of indoor metal enclosed switchgear, when Erie Thames has operating control of any interrupter switches, the assembly shall further incorporate ground rod parking stands and stirrups per Erie Thamess Specifications.)

- Details of vault construction (if indoor substation).

- Manufacturer's drawings of metal-enclosed switchgear showing internal arrangement of equipment, clearances, means of access, interlocking and provision for personal safety. Where Erie Thames cables terminate in the switchgear, the customer shall provide suitable terminators for the size and type of cable as specified by Erie Thames.

- When the customer's switchgear is used for loop feeding Erie Thames supply cables, provision for padlocking the in and out load interrupter switches and the associated bay doors shall be required.

- Indoor and outdoor switchgear assemblies shall contain a space heater and protective guard in each bay, along with thermostat(s), sized to promote air circulation and to prevent condensation from forming.

- At the discretion of Erie Thames, the customer shall make provisions for a future system neutral connection to the customer's dead-ending pole or structures installed by Erie Thames. Where Erie Thames neutral terminates in the customer's switchgear, the customer shall provide a suitable connector on the ground bus for the size and type of cable specified by Erie Thames.

3.4.12 Pre-Service Inspection

The customer shall present to Erie Thames a final "Pre-service Inspection Report" a minimum of 3 working days before connection can be affected.

The "Pre-Service Inspection Report" shall outline and document the results of all tests and inspection carried out on the substation components. The information contained in the report must be to the satisfaction of Erie Thames before connection can be authorized.

The "Pre-Service Inspection Report" shall be required in case of:

- ***<u>New Substation</u>****: in which case all components of the substation shall be reported upon.*

- ***<u>Modified substation</u>****: in which case all components of the substation shall be reported upon.*

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by Erie Thames prior to connection.

Erie Thames or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of Erie Thames and subject to inspection by Erie Thames.

(Refer to section 2.1.4 for further inspection details)

3.5 Embedded Generation

3.5.1 General

An Embedded Generator shall provide Erie Thames with proof of compliance of IESO or OEB registration Requirements, and appropriate Licences.

Erie Thames shall collect costs reasonably incurred with making an offer to connect a generator from the entity requesting the connection. Costs reasonably incurred include costs associated with:

- Preliminary review for connection requirements.
- Detailed study to determine connection requirements.
- Final proposal to the generator.

A Generator that is or wishes to become connected to Erie Thames distribution system shall enter into a Connection Agreement with Erie Thames.

If damage or increased operating costs result from a connection with a Generator, the Generator shall reimburse Erie Thames for these costs.

The Embedded Generator is responsible for providing suitable embedded generator equipment to protect his plant and equipment for any conditions on Erie Thames and interconnected transmission systems such as reclosing, faults and voltage unbalance.

To incorporate the connection of embedded generator to the distribution system, the line/feeder protection including settings and breaker reclosing circuits must be reviewed and modified if necessary by Erie Thames or transmission authority. This process may be complex and may require significant time.

The embedded generator must submit a proposed single line diagram and protection scheme for review to Erie Thames contact as identified by Erie Thames.
Based on the transformer connection proposed by the embedded generator additional significant protection cost may be incurred (e.g. delta HV transformer winding may require 3 phase HV breaker / reclosure device). The embedded generator shall not order the protection equipment and transformer until the station line diagram is reviewed and accepted by Erie Thames.

The purpose of Erie Thames review is to establish that the embedded generator electrical interface design meets Erie Thames requirements.

The protection schemes shall incorporate adequate facilities for testing/maintenance.

Negative phase sequence protection shall be installed where required, to detect abnormal system condition as well as to protect the generator.

The embedded generator may be required to install utility grade relays for those protections that could affect Erie Thames or transmission authority system.

The embedded generator may be required to submit a Ground Potential Rise study for review by Erie Thames, if telecommunications circuits are specified for remote transfer trip protection.

3.5.2 Protection

The embedded generator should provide protection systems to cover the following conditions:

3.5.2.1 Internal Faults

The Generator should provide adequate protections to detect and isolate generator and station faults.

3.5.2.2 External Faults

The protection system should be designed to provide full feeder coverage complete with a reliable DC supply. In some cases redundancy in protection schemes may be required.

Normally the following fault detection devices are required for synchronous generator(s) installation(s).

3.5.2.3 Ground Faults

When the HV winding of the Generator station transformer is wye connected with the neutral solidly grounded, then ground over-current protection in the neutral is required to detect ground faults.

If the Embedded generator station transformer HV winding connected to Erie Thames system is ungrounded wye or delta, then ground under-voltage and ground over-voltage protections shall be required to detect ground faults.

Depending on the size, type of generator and point of connection, a distributor may require the relaying system to be duplicated, complete with separate auxiliary trip relays and separately fused DC supplies to ensure reliable protection operation and successful isolation of the embedded generator.

3.5.2.4 Phase Faults

To detect phase faults, at least one of the following protections should be installed with acceptable redundancy where required depending on fault values:

- Distance
- Phase directional over-current
- Voltage-restrained over-current
- Over-current
- Under-voltage

3.5.2.5 Islanding/Abnormal Conditions

Voltage and frequency protections are required to separate the embedded generator from the distribution system for an islanded condition and thus maintain the quality of supply to distribution system customers. This also will enable speedy restoration of the distribution system.

Typically, the protections required to detect islanding/abnormal conditions are:

- Over-voltage
- Under-voltage
- Over-frequency
- Under-frequency
- Voltage-balance

The above protections should be timed to allow them to ride through minor disturbances.

3.5.3 Induction Generator

Due to the operating characteristics of the induction generator the protection package required is normally less complex than the synchronous generator. An embedded generator should design the protection scheme to trip for the same conditions as stated for synchronous generators. An induction generator is an asynchronous machine that requires an external source such as a healthy distribution system to produce normal 60 Hz power. Alternatively, if there is an outage in the distribution system then there is unlikely to be 60 Hz output from the induction generator. In certain instances, an induction generator may continue to generate electric power after the source is removed. This phenomenon, known as self-excitation, can occur whenever there is sufficient capacitance in parallel with the induction generator to provide the necessary excitation and when the connected load has certain resistive characteristics.

3.5.4 DC Remote Tripping / Transfer Tripping

Remote or transfer tripping may be required between the Generator and the feeder circuit breaker if the Generator is connected at a critical location in the distribution system. This feature will provide for isolation of the embedded generator when certain faults or system disturbances are detected at the feeder circuit breaker location.

Additional Protection Features, such as Remote Trip and Generator end open signal, may be required in some applications.

3.5.5 Maintenance

An Embedded Generator shall have a regular scheduled maintenance plan to assure Erie Thames that all connection devices and protection & control systems are maintained in good working order. These provisions shall be included in the Connection Agreement. A complete copy of the inspection report shall be delivered to Erie Thames within 30 days.

In developing a maintenance plan, the Generator should consider the following requirements:

- Qualified personnel should carry out all inspections and repairs.

- Periodic tests should be performed on protection systems to verify that the system operates as designed. Testing intervals for protection systems should not exceed four (4) years for microprocessor-based systems and two (2) years for electro-mechanical based systems.

- Isolating devices at the point of connection should be operated at least once per year.

- The Generator facility should be inspected visually at least once per year to note obvious maintenance problems such as broken insulators or other damaged equipment.

- Any deficiencies identified during inspections shall be noted and repairs scheduled as soon as possible, with timing dependent on the severity of the problem, due diligence concerns (of both Erie Thames and the Generator) and financial and material requirements. Erie Thames shall be notified of any deficiencies involving critical protective equipment.

- Erie Thames shall be provided with copies of all relevant inspection and repair reports that may affect the protection and performance of Erie Thames systems. Erie Thames has the right to witness any relevant test being performed by the generator.

3.6 Embedded Market Participant

An Embedded Market Participant shall provide Erie Thames with proof of compliance of IESO registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Market Participant must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to Erie Thames distribution facilities.

3.7 Embedded Distributor

An Embedded Distributor shall provide Erie Thames with proof of compliance of IESO and OEB registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Distributor must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to Erie Thames distribution facilities.

3.8 Miscellaneous Small Services

This section pertains to the supply of electrical energy for Street Lighting, Traffic Signals, Bus Shelters, Telephone Booths, Cable T.V. Amplifiers, Decorative Street Lighting, Bill Boards, and other similar small loads.

3.8.1 General

At the discretion of Erie Thames, the service voltage will be:

120/240 volts, single phase three wire or
120 volts, single phase two wire or
347/600V three phase, four wire

The method and location of the supply will vary based on the conditions present on Erie Thames plant, and will be established for each application through consultation with Erie Thames.

Where specified by Erie Thames during the Early Consultation process, the Customer will provide underground ducts to Erie Thames specifications.
The Owner shall be responsible for all costs associated with the supply and installation of service conductors

Erie Thames at the Owners' expense will install required transformation.

Where at the discretion of Erie Thames, a meter is not installed, energy consumption will based on the connected wattage and the calculated hours of use.

Prior to energization of a service Erie Thames will require notification from the ESA that the installation has been inspected and approved for connection.

3.8.2 Early Consultation

The Owner shall supply a completed Electrical Service Connection Form to Erie Thames well in advance of installation commencement to allow Erie Thames time for proper planning, ordering of equipment etc. Information required includes:

- Required in-service date
- Requested Service Entrance Capacity and voltage rating of the service entrance equipment
- Locations of other services, gas, telephone, water and cable TV
- Survey plan and site plan indicating the proposed location of the service equipment with respect to public rights-of way and lot lines.

3.8.3 Street Lighting

Town street-lighting that is designed, installed, and maintained by Erie Thames shall be fully funded by the Municipality to ensure adherence to the Affiliate Relationship Code and Erie Thames Distribution Licence.

3.8.4 Traffic Signals

Traffic Signals and Crosswalk Lights are owned and maintained by the applicable road authority.

3.8.5 Bus Shelters

Bus Shelter Lighting is owned and maintained by the Customer.

3.8.6 Decorative Street Lighting

Such installations could be lighting for festive occasions or "neighbourhood character" street-scaping and will be maintained by the Customer.

SECTION 4 GLOSSARY OF TERMS

“Conditions of Service” means the document developed by Erie Thames in accordance with subsection 2.3 of the Distribution System Code, that describes the operating practices and connection rules for Erie Thames;

“Condominiums” are located on common land, which is the property of a condominium corporation or is owned by the Owner of all of the units (rental property). These units usually front onto internal roads that are also privately owned;

“Condominium Development” is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit and have direct outside access at ground level;

“Connection” means the process of installing and activating connection assets in order to distribute electricity;

“Connection Agreement” means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection;

“Connection assets” means that portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributors’ main distribution system and the ownership Demarcation Point with that customer;

“Consumer” means a person who uses, for the person’s own consumption, electricity that the person did not generate;

“Customer” means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions;

“Demand meter” means a meter that measures a consumers’ peak usage during a specified period of time;

“Demarcation Point” means the point at which the obligation of Erie Thames ends and those of the Customer begin for the purposes of maintenance and repair of the distribution service;

“Disconnection” means a deactivation of connection assets, which results in cessation of distribution services to a consumer;

“Distribute”, with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

“Distribution losses” means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows;

“Distribution loss factor” means a factor(s) by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.;

"Distribution services" means services related to the distribution of electricity and the services the Board has required distributors to carry out.

"Distribution system / plant" means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many customers and the connection assets used to connect a customer to the main distribution system;

"Distribution System Code," means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of a distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards of distribution systems;

"Distributor" means a person who owns or operates a distribution system;

***"Electricity Act*"** means the *Electricity Act, 199*8, S.O. 1998, c.15, Schedule A;

"Energy Competition Act" means the *Energy Competition Act*, *199*8, S.O. 1998, c. 15;

"Electrical Safety Authority" or **"ESA"** means the person or body designated under the *Electricity Act* regulations as the Electrical Safety Authority;

"Embedded Distributor" means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor;

"Embedded Generation Facility" means a generator whose generation facility is not directly connected to the IESO-controlled grid but instead is connected to a distribution system;

"Embedded Load Displacement Generation Facility" means an embedded generation facility connected to the customer side of the revenue meter where the generation facility does not inject electricity into the distribution system for the purpose of sale;

"Embedded Market Participant" means a consumer who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system;

"Emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity, or that could adversely affect the reliability of the electricity system;

"Emergency backup generation facility" means a generation facility that has a transfer switch that isolates it from a distribution system;

"Enhancement" means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth;

"Expansion" means an addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example, by increasing the length of the distribution system;

“Four-quadrant Interval Meter” means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the customer;

“Generate”, with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system;

“Generation Facility” means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose;

“Generator” means a person who owns or operates a generation facility;

“Geographic Distributor” with respect to a load transfer, means Erie Thames that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer;

“Good Utility Practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

“Holiday” means a Saturday, Sunday, statutory holiday, or any day as defined in the Province of Ontario as a legal holiday;

“IESO” means the Independent Electricity Market Operator established under the *Electricity Act*;

“IESO-Controlled Grid” means the transmission systems with respect to which, pursuant to agreements, the IESO has authority to direct operation;

“Interval meter” means a meter that measures and records electricity use on an hourly or sub-hourly basis;

“Large Embedded Generation Facility” means an embedded generation facility with a name-plate rated capacity of 10MW or more;

“Lies Along” means a property can be connected to Erie Thames distribution system without an expansion or enhancement, and meets the conditions listed in the Conditions of Service of Erie Thames who owns or operates the distribution line.

“Load Transfer” means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point;

“Load Transfer Customer” means a customer that is provided distribution services through a load transfer;

“Market Rules” means the rules made under section 32 of the *Electricity Act*;

"Measurement Canada" means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Ac*t, 1980-81-82-83, c. 87., and Electricity and Gas Inspection Regulations (SOR/86-131);

"Medium Sized Embedded Generation Facility" means an embedded generation facility with a name-plate rated capacity of less than 10 MW and:

a) more than 500 kW in the case of a facility connected to a less than 15kV line;
b) more than 1 MW in the case of a facility connected to a 15 kV or greater line;

"Meter Service Provider" means any entity that performs metering services on behalf of a distributor, generator, or registered market participant;

"Meter Installation" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment;

"Metering Services" means installation, testing, reading and maintenance of meters;

"Micro Embedded Load Displacement Generation Facility" means an embedded load displacement generation facility with a name-plate rated capacity of 10 kW or less;

"Ontario Electrical Safety Code" means the code adopted by O. Reg. 164/99 as the Electrical Safety Code;

"Ontario Energy Board Act" means the *Ontario Energy Board Act, 199*8, S.O. 1998, c.15, Schedule B;

"Operational Demarcation Point" means the physical location at which a distributors' responsibility for operational control of distribution equipment including connection assets ends at the customer;

"Ownership Demarcation Point" means the physical location at which a distributors' ownership of distribution equipment including connection assets ends at the customer;

"Physical Distributor" with respect to a load transfer, means Erie Thames that provides physical delivery of electricity to a load transfer customer, but is not responsible for connecting and billing the load transfer customer directly;

"Point of Supply" with respect to an embedded generation facility, means the connection point where electricity produced by the generation facility is injected into a distribution system;

"Rate" means any rate, charge or other consideration, and includes a penalty for late payment;

"Rate Handbook" means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates;

"Regulations" means the regulations made under the *Act or the Electricity Act*;

"Retail", with respect to electricity means,

a) To sell or offer to sell electricity to a consumer
b) To act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
c) To act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity.

"Retail Settlement Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributors' obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

"Retailer" means a person who retails electricity;

"Service Area" with respect to a distributor, means the area in which Erie Thames is authorized by its license to distribute electricity;

"Small Embedded Generation Facility" means an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1MW or less in the case of a facility connected to a 15 kV or greater line;

"Total losses" means the sum of distribution losses and unaccounted for energy;

"Townhouses" are usually a free hold property, the land is owned by the individual Owners of each unit, fronting onto a municipal street;

"Townhouse Development" is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit, and have direct outside access at ground level;

"Transmission System" means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

"Transmission System Code" means the Board approved code that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with customers, as well as establishing the standards for connection of customers to, and expansion of a transmission system;

"Transmit" with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts;

"Transmitter" means a person who owns or operates a transmission system;

"Unaccounted-for Energy" means all energy losses that cannot be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and un-metered loads, energy theft and non-attributable billing errors;

"Un-metered loads" means electricity consumption that is not metered and is billed based on estimated usage;

“Validating, Estimating and Editing (VEE)” means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes;

“Wholesale Market Participant” means a person that sells or purchases electricity or ancillary services through the IESO-administered markets;

SECTION 5   APPENDICIES

Appendix 1 - Electrical Service Connection Form

Appendix 2 - Electric Service Meter Base/ Service Verification Form

Appendix 3 - Policies:

5.0 Opening and Closing of Accounts at the Request of a Third Party
6.1 Security Deposits
7.0 Collections Overview
7.1 Customer Collections
7.2 Retailer Collections
7.3 Use of Load Control Devices
8.0 Disconnection/Reconnection Overview
8.1 Disconnection/Reconnection
8.2 Disconnection/Reconnection by Request
8.3 Safety and Reliability
8.4 Unauthorized Use of Electricity

Appendix 4 – Summary of Changes

Appendix 1

ERIE THAMES POWER

143 Bell Street, Box 157 Ingersoll ON N5C 3K5 (519)485-1820 Toll free 1866-878-0037 FAX 15194855838
www.eriethamespower.com

CUSTOMER REQUEST FOR INDUSTRIAL COMMERCIAL ELECTRICAL SERVICE CONNECTION

WO# ____________________

PROJECT LOCATION	
INGERSOLL	
AYLMER	
BEACHVILLE	
NORWICH	
TAVISTOCK	
THAMESFORD	
OTTERVILLE	
BURGESSVILLE	
PORT STANLEY	
BELMONT	
EMBRO	

BILLING INFORMATION

SERVICE ADDRESS: ____________________
NAME OF PROJECT: ____________________
NAME OF APPLICANT: ____________________
BILLING ADDRESS: ____________________
TELEPHONE: CELL: ____________________
EMAIL ADDRESS: FAX:

CONTRACTOR INFORMATION

CONTACT NAME: ____________________
TELEPHONE: ____________________
FAX: ____________________

TYPE OF SERVICE

NEW
UPGRADE

CUSTOMER ACCT#

0

SERVICE VOLTAGE

120/208 THREE PHASE
347/600 THREE PHASE
PRIMARY 27.6/16KV
TRANSFORMER TYPE
120/240 SINGLE PHASE

MAIN SERVICE (AMPS)

100
200
400
600
800
1000
1200
OTHER

MAIN SERVICE CONDUCTOR

SIZE: ____________________
TYPE: ____________________

CONDUCTORS PER PHASE
MAIN BREAKER CAPACITY
FUSED AT 80%
CONNECTED KW
ESTIMATED PEAK KW

RESIDENTIAL	
GS <50KW	
GS>50KW NON INTER	
GS >50KW INTER	
GS >1000KW	
GS >3000KW	
GS >5000KW	

TRANSFORMER OWNER

ETP	CUSTOMER	SIZE kva

METERING

TOTAL# OF METERS
SINGLE PHASE

INSTRUMENT TRANSFORMERS LOCATION

UTILITY CABINET
SWITCHGEAR
NOT REQUIRED

FORM COMPLETED EMAIL TO: E-MAIL TO SUPERVISORS

COMMENTS

____

REQUIRED IN SERVICE DATE:____________ SIGNATURE:____________________ 58-03

Appendix 2

ERIE THAMES POWERLINES
CORPORATION

Electric Service Meter Base/ Billing Address Verification Form

This form **must** be completed by the Owner and/or their Electrical Contractor if applicable prior to service connection.

Electric Service Municipal Address: ____________________

Name of Owner: ____________________

Telephone: ( ) ____________________ **Fax:** ( ) ____________________

Name of Contractor: ____________________

Telephone: ( ) ____________________ **Fax:** ( ) ____________________

In area (A) provided below, carefully sketch the Front View layout of the Electric Meter Base(s).
Match the corresponding (B) BILLING ADDRESS for each meter base(s) shown in (A).

(A) FRONT VIEW OF ELECTRIC METER BASE(S)	(B) BILLING ADDRESS
	1)
	2)
	3)
	4)
	5)
	6)
	5)
	7)
	8)
	9)
	10)
	11)

I/We the undersigned, acknowledge the information provided above has been verified and is accurate.

Signature of Owner: ____________________ **Date:** ____________________

Signature of Contractor: ____________________ **Date:** ____________________

Appendix 3

ERIE THAMES POWERLINES	**Policy # ETPL-2011-5.0**	Approved By: President Approved Date: January 2012
RRAM #:	**Opening and Closing of Accounts at the Request of a Third Party**	Revision: 1.0

5.0.1 PURPOSE:

The purpose of this policy is to document the rules described in the Distribution System Code -Section 2.8 Opening and Closing of Accounts to ensure that Erie Thames Powerlines complies with the rules when a request is received by a third party to open or close an account with Erie Thames Powerlines.

5.0.2 POLICY STATEMENT:

When Erie Thames opens or closes an account for a property in the name of a person at the **request of a third party**, Erie Thames shall:

- within 15 days of the opening of the account contact the person by telephone, if the person cannot be reached by telephone a letter will be hand delivered to the subject property advising of the opening of the account and requesting that the person confirm that he or she agrees to be the named customer;
- advise the third party that the account will not be set up as requested if Erie Thames does not receive confirmation from the intended customer prior to the scheduled move in date;
- not be required to send a letter advising of the opening of the account where the request to open the account is made in writing by the person's solicitor or person in possession of a valid Power of Attorney for the person;
- where Erie Thames has opened an account for a property in the name of a person at the request of a third party, Erie Thames shall not seek to recover from the third party any charges for service provided to the property unless the third party has agreed to be the customer of Erie Thames in relation to the property;
- where a request was received to close or transfer an account in relation to a rental unit from someone other than the occupant, Erie Thames shall not seek to recover any charges for service provided to that rental unit or residential property after closure of the account from any person other than the occupant, including the landlord for the residential complex or a new owner of the residential property, unless the person has agreed to assume responsibility for those charges.

Erie Thames may enter into an agreement with a landlord whereby the landlord agrees to assume responsibility for paying for continued service to the rental property after closure of a tenant's account.

The agreement with the landlord may be established by verbal request over the telephone. Erie Thames will document confirmation of the verbal request on the applicable account for the duration of the agreement with the landlord.

Erie Thames shall accept written agreements in electronic form (email) in accordance to the *Electronic Commerce Act, 2000.*

5.0.3 RESPONSIBILITIES:

Management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

5.0.4 REFERENCES:

Distribution System Code – The Ontario Energy Board

ERIE THAMES POWERLINES	Policy # ETPL-2011-6.1	Approved By: President
		Approved Date: January 2012
	Security Deposits	Revision: 3.1
RRAM #:		

6.0.1 PURPOSE:

This policy describes the terms and conditions Erie Thames Powerlines will use for collection, maintaining and returning customer security deposits which shall be consistent with the provisions described in the Distribution System Code.

In accordance with the Distribution System Code, Erie Thames Security Deposit Policy shall include:

- a list of all potential types/forms of security accepted;
- a detailed description of how the security is calculated;
- limits on the amount of security required;
- the planned frequency, process and timing of updating security;
- a description of how interest payable to customers is determined;
- criteria customers must meet to have security deposit waived and/or returned; and
- methods of enforcements where a security deposit is not paid.

6.0.2 POLICY STATEMENT:

Erie Thames Powerlines may use any risk mitigation options available to manage customer non-payment risk. Erie Thames Powerlines shall not discriminate among customers with similar risk profiles or risk related factors except where expressly permitted under the Distribution System Code.

Erie Thames Powerlines will comply with the deposit requirements as defined in the Distribution System Codes but may waive these requirements in favour of a customer or potential customer.

Erie Thames Powerlines will disclose to the customer the reasons for requiring the security deposit.

6.0.3 FORM OF SECURITY DEPOSIT:

Residential

The form of payment of a security deposit for a residential customer shall be cash or cheque at the discretion of the customer or such other form as is acceptable by Erie Thames Powerlines.

Erie Thames Powerlines shall permit a residential customer to pay a security deposit in equal instalments over a 6 month period.

Erie Thames Powerlines shall allow a residential customer to repay a security deposit that was applied in full or in part to the residential customers account to offset amounts owing at that time as an attempt to avoid a disconnection notice for non-payment, in equal instalments over a 6 month period.

The customer may elect to pay the security deposit over a shorter period of time.

General Service

The security deposit will be in the form of cash, cheque or an automatically renewing irrevocable letter of credit from a bank for non residential customers.

Erie Thames Powerlines may also accept other forms of security such as surety bonds and third party guarantees.

Non-residential customer's shall pay the security deposit in equal instalments over 4 months, the first instalment being due on the implementation of an implied contract or the signing of service agreement. The customer may elect to pay the security deposit over a shorter period of time.

6.0.4 METHOD OF CALCULATION AND LIMIT OF SECURITY DEPOSIT:

The maximum amount of the security deposit that a customer is required to pay shall be calculated as follows:

- the billing cycle factor times the estimated bill based on the customer's average monthly load with Erie Thames Powerlines during the most recent 12 consecutive months within the past two years.
- Where relevant usage information is not available for the customer for 12 consecutive months within the past two years or the billing system is not capable of making the calculation, the customer's average monthly load shall be based on a reasonable estimate made by Erie Thames Powerlines.

Where a customer has a payment history which discloses more than one disconnection notice in a relevant 12 month period, Erie Thames Powerlines may use the customer's highest actual or estimated monthly load for the most recent 12 consecutive months within the past 2 years for the purposes of calculating the maximum amount of the security deposit.

For a low-volume consumer or designated consumer the price estimate used in calculating competitive electricity costs shall be the same as the price used by the IESO for the purpose of determining maximum net exposures and prudential support obligations for Erie Thames Powerlines.
If a non-residential customer with a >50kW demand rate can provide a credit rating from a recognized credit rating agency, the maximum amount of the security deposit required by Erie Thames Powerlines shall be reduced in accordance with the following table:

Credit Rating
(Using Standard and Poor's Rating Terminology)
Allowable Reduction in Security Deposit

AAA- and above or equivalent 100%
AA-, AA, AA+ or equivalent 95%
A-, From A, A+ to below AA or equivalent 85%
BBB-, From BBB, BBB+ to below A or equivalent 75%
Below BBB- or equivalent 0%

6.0.5 PLANNED FREQUENCY, PROCESS AND TIMING OF UPDATING SECURITY DEPOSITS:

Erie Thames Powerlines shall review every customer's security deposit at least once every calendar year to determine whether the entire amount of the security deposit is to be returned to the customer or adjusted based on a re-calculation of the maximum amount of the security deposit.

Where a residential customer has paid the security deposit in instalments, Erie Thames shall conduct a review of the customer's security deposit in the calendar year in which the anniversary of the first instalment occurs.

When Erie Thames Powerlines determines in conducting a review that the amount of the security deposit is to be adjusted upwards based on the recalculation of the maximum amount of the security deposit, Erie Thames Powerlines shall permit the customer to pay the adjusted amount in equal instalments paid over a period off at least 6 months.

Erie Thames shall allow a customer to repay a security deposit that was applied to the customer's account to offset amounts owing in equal instalments over at least 6 months.

Any security deposit received from the customer, upon closure of the customer account, shall be applied to the final bill prior to change in service and can be used to off-set other amounts owing by the customer to Erie Thames Powerlines. The balance shall be returned within six weeks of closure of the account.

6.0.6 INTEREST PAYABLE:

The interest shall accrue monthly on security deposits made by cash or cheque commencing on receipt of the total deposit. The interest shall be at the Prime Business Rate as published on the Bank of Canada website less 2 percent, updated quarterly. The interest accrued shall be paid at least once every 12 months or on return or application of the security deposit or closure of the account, whichever comes first, and may be credited to the account.

6.0.7 CRITERIA REQUIRED FOR WAIVERED AND/OR RETURN OF SECURITY DEPOSIT:

Erie Thames Powerlines reserves the right to collect a security deposit from a customer that is not billed by a competitive retailer under retailer-consolidated billing unless the customer has a good payment history of:

- 1 year in the case of a residential customer,
- 5 years in the case of a non-residential customer in < 50 kW demand rate class, or
- 7 years in the case of a non-residential customer in any other rate class.

The time period that makes up the good payment history must be the most recent period of time and some of the time period must occur in the previous 24 months.

A customer is deemed to have a good payment history, unless, during the relevant time period the customer has received:

- more than one disconnection notice from the Erie Thames Powerlines, or
- more than one cheque given to the Erie Thames Powerlines by the customer has been returned for insufficient funds, or
- more than one pre-authorized payment to Erie Thames Powerlines has been returned for insufficient funds, or
- a disconnection/collection trip has occurred, or
- all or part of a security deposit held on file was applied to offset amounts owing by a residential customer prior to disconnection of their electricity service for non-payment of account and the customer is required by Erie Thames to pay back the security deposit.

Erie Thames Powerlines shall not require a security deposit if the customer provides the following prior to the implementation of service:

- the customer provides a letter from another distributor or gas distributor in Canada confirming a good payment history for the most recent relevant time period, some of this time period must have incurred within the last 24 months,
- a customer, other than a customer in a >5,000 kW demand rate class, that provides a satisfactory credit check made at the customer's expense,
- a customer has been qualified as an eligible low-income customer and requests a waiver,
- If a non-residential customer in any class other than <50kW demand rate can provide a credit rating from a recognized credit rating agency, the maximum amount of the security deposit required by Erie Thames Powerlines shall be reduced in accordance with the following table:

<u>Credit Rating</u>
(Using Standard and Poor's Rating Terminology)
Allowable Reduction in Security Deposit

AAA- and above or equivalent 100%
AA-, AA, AA+ or equivalent 95%
A-, From A, A+ to below AA or equivalent 85%
BBB-, From BBB, BBB+ to below A or equivalent 75%
Below BBB- or equivalent 0%

In the case of a customer in a >5,000kW demand rate class, where the customer is now in a position that it would be exempt from paying a security deposit, however, had previously paid a security deposit to Erie Thames Powerlines, Erie Thames Powerlines is only required to return 50% of the security deposit.

Erie Thames shall give notice to all residential customers, at least annually, that any residential customer that qualifies as an eligible low-income customer may request and receive a refund of any security deposit previously paid to Erie Thames, after application of the security deposit to any outstanding amounts owing on the customer's account.

Erie Thames shall advise the eligible low-income customer that has requested a refund, within 10 days of the request, that the balance remaining after application of the security deposit to the customer's outstanding arrears will be credited to the customer's account if the remaining amount is less than one month's average billing. Where the remaining amount is equal to or greater than one month's average billing the customer may elect to receive the refund by cheque. Erie Thames will issue the cheque within 11 days of the customer's request for payment by cheque.

Erie Thames Powerlines shall apply all or part of any security deposit held on account against any amounts owing prior to issuing a disconnection notice to a residential customer for non-payment.

Erie Thames Powerlines may at its discretion reduce the amount of a security deposit for any reason including where the customer pays under an interim payment arrangement and where the customer makes pre-authorized payments.

Erie Thames shall promptly return any security deposit received from a customer within six weeks of the closure of the customer's account, subject to Erie Thames right to use the security deposit to set off other amounts owing by the customer to Erie Thames.

Erie Thames shall apply a security deposit to the final bill prior to the change in service where a customer changes from SSS to a competitive retailer that uses retailer-consolidated billing or a customer changes billing options from distributor-consolidated billing to split billing or retailer-consolidated billing, any remaining amounts will be promptly returned to the customer.

Erie Thames shall not pay any portion of a customer's security deposit to a competitive retailer.

Erie Thames may retain a portion of the security deposit where a change is made from distributor-consolidated billing to split billing that reflects the non-payment risk associated with the new billing options.

Where all or part of a security deposit has been paid by a third party on behalf of the customer, Erie Thames shall return the amount of the security deposit paid by the third party, including interest, where applicable, to the third party when:

- the third party paid all or part of the security deposit directly to Erie Thames;
- the third party requested at the time the security deposit was paid that Erie Thames return all of part of the security deposit to them rather than the customer;
- there is not then any amount overdue for payment by the customer that Erie Thames is permitted by Code to offset using the security deposit.

6.0.8 METHOD OF ENFORCEMENT WHERE SECURITY DEPOSIT IS NOT PAID:

Failure to pay the security deposit as required will result in the immediate implementation of Erie Thames Powerlines collection policy process which may lead to the discontinuation of electrical service.

6.0.9 DEFINITIONS:

"The Billing Cycle Factor" is 2.5 if the customer is billed monthly, 1.75 if the customer is billed bi-monthly and 1.5 if the customer is billed quarterly.

"Disconnection/Collection Trip" is a visit to a customer's premises by an employee or agent of the Erie Thames Powerlines to demand payment of an outstanding amount or to shut off or limit distribution of electricity of the customer failing payment.

6.0.10 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

6.0.11 REFERENCES:

The Electricity Act, 1998 – Province of Ontario, Ministry of Energy, Science and Technology

Market Rules – The Independent Electricity Market Operator

Distribution System Code – The Ontario Energy Board

Retail Settlement Code – The Ontario Energy Board

Distribution Rates Handbook – The Ontario Energy Board

7.0.1 PURPOSE:

The purpose of this policy is to establish a process to ensure that every attempt has been made to avoid disconnection for non-payment of account and that money owed to Erie Thames Powerlines by consumers is collected.

7.0.2 POLICY STATEMENT:

Erie Thames Powerlines will collect all outstanding money owed from Customers and Retailers served by Erie Thames Powerlines distribution system in accordance with the principles defined in the *Electricity Act (1998),* the Electricity Distribution Rate Handbook, Distribution System Code, Retail Settlement Code and Standard Supply Service Code.

The policies in this set are intended to provide guidance to Erie Thames Powerlines managers and staff, and to help them make operational decisions that are consistent with applicable codes and regulations.

7.1 Customer Collections
7.2 Retailer Collections
7.3 Use of Load Control Devices

7.0.3 DEFINITIONS:

Customer and Consumer will be understood herein as one and the same.

Distributor-Consolidated Billing is when a retailer marketer who has signed contracts in Erie Thames Powerlines service area and has opted for the distributor to do the billing and collection of the electricity commodity and all related non-competitive charges.

Disconnection/Collect Trip is a visit to a customer's premises by an employee or agent of Erie Thames to demand payment of an outstanding amount or to shut off or limit distribution of electricity to the customer failing payment.

Electricity Charges, for the purpose of this policy, are charges that appear under the sub-headings "Electricity, Delivery", "Regulatory Charges", and "Debt Retirement Charge" as described in Ontario Regulation 275/04 (Information on Invoices to Low-volume Consumers of Electricity) made under the Act, and all applicable taxes. Where applicable, charges prescribed by regulations under section 25.33 of the *Electricity Act, 1998* and all applicable taxes on those charges, and OEB approved late payment fees, specific service charges and such other charges and applicable taxes associated with the consumption of electricity as may be required by law to be included, as may be designated by the Ontario Energy Board, not including security deposits.

Eligible Low-Income Customer means a residential electricity customer who has a pre-tax household income at or below the pre-tax Low Income Cut-Off, according to Statistics Canada, plus 15%, taking into account family size and community size, as qualified by a Social Service agency or Government Agency; or a residential electricity customer who has been qualified for Emergency Financial Assistance.

Emergency Financial Assistance means any OEB approved emergency financial assistance program made available by a distributor or eligible low-income residential customers.

Errors and Omissions Excepted Erie Thames Powerlines shall reserve the right to make adjustments to any bill issued in error either in whole or in part.

Late Payment Charge is an OEB approved interest charge that is applied after a specified date or a due date on a customer's bill.

Licensed Competitive Retailer is a company that has a valid electricity retailer's license from the Ontario Energy Board.

Load Control Device means a load limiter, timer load interrupter or similar device that limits or interrupts normal electricity service.

Load Limiter Device means a device that will allow a customer to run a small number of electrical items in his or her premises at any given time, and if the customer exceeds the limit of the load limiter, then the device will interrupt the power until it is reset.

Timed Load Interrupter Device means a device that will completely interrupt the customer's electricity intermittently for periods of time and allows full load capacity outside of the time periods that the electricity is interrupted.

Non-Payment Risk Mitigation Erie Thames Powerlines may use any risk mitigation options available under the law to manage consumer non-payment risk.

Retailer-Consolidated Billing is when the retail marketer opts to do the billing and collection of the electricity commodity and all related non-competitive charges.

Split Billing is when the retail marketer bills the customer for the electricity charges and Erie Thames Powerlines bills for the customer for non-competitive, debt retirement and distribution charges. The retailer and the distributor shall each be responsible for the collection of their own accounts.

Standard Service Supply Customer is a company or person who purchases electricity at spot market price or statutory pricing from Erie Thames Powerlines distribution system as a direct pass through from the IESO.

7.0.4 COLLECTION PAYMENT METHODS:

Erie Thames Powerlines may accept one or more of the following methods of payment but is not obligated to offer all methods:

Cash
Payment made through most Financial Institutions including telephone & computer banking
Certified Cheque
Money Order or Bank Draft
Credit Card issued by a Financial Institution
Preauthorized Payment Plan

7.0.5 RESPONSIBILTIES:

The management of the company is responsible for the approval of the policies contained in this manual.

7.0.6 REFERENCES:

The Electricity Act, 1998
Electricity Distribution Rate Handbook – The Ontario Energy Board
Retail Settlement Code– The Ontario Energy Board
Distribution Rate Handbook – The Ontario Energy Board
Distribution System Code – The Ontario Energy Board

ERIE THAMES POWERLINES	Policy # ETPL-2010-7.1	Approved By: President, ETPL Approved Date: January 2012
	Customer Collections	Revision: 4.0
RRAM #:		

7.1.1 PURPOSE:

This policy confirms that Erie Thames must be prudent in their collection process to protect the Corporation from unpaid invoices. The detailed policies in this set are intended to establish and document a process that will provide guidance to Erie Thames management and staff, to help them make operational decisions to ensure that monies owed to Erie Thames by the consumer or retailer are collected in a timely manner.

7.1.2 POLICY STATEMENT:

Erie Thames will take steps to collect the total amount for the customer's bill, if not paid within the time specified in S.2.6.3 of the Distribution System Code, which shall be a minimum of sixteen calendar days from the date on which the bill was issued.

Erie Thames will deem the bill to have been issued to the customer:

a) if sent by mail, on the third day after the date on which the bill was printed;

b) if made available over the internet, on the date on which an e-mail is sent to the customer notifying the customer that the bill is available for viewing over the internet;

c) if sent by e-mail, on the date on which the e-mail is sent; or

d) if sent by more than one of the methods listed in (a) to (c), on whichever date of deemed issuance occurs lasts.

Erie Thames shall determine the date on which payment of the bill has been received from the customer:

a) if paid by mail, three days prior to the date on which the payment was received;

b) If paid at a financial institution or electronically, on the date on which the payment is acknowledged or recorded by the customers financial institution; or

c) if paid by credit card issued by a financial institution, on the date and at the time that the charge is accepted by the financial institution.

Erie Thames shall deem a bill issued to a customer as unpaid when the minimum payment period has elapsed. A late payment charge may be applied to the customer's account.

Erie Thames shall begin the collection process immediately following the application of late payment charge.

Erie Thames shall allocate any payment made by a residential customer whose bill includes charges for goods or services other than electricity charges first to the electricity charges and then if funds are remaining, to the other charges.

Erie Thames shall not impose a late payment charge, issue a disconnection notice or disconnect the customer's electricity supply if the payment on account is sufficient to cover the electricity charges.

Erie Thames shall treat all customers in the same rate class in a non-discriminatory fashion when collecting unpaid accounts.

7.1.3 Erie Thames shall make available to any residential customer who is unable to pay their outstanding electricity charges the opportunity to enter into an arrears payment agreement.

If the customer declines Erie Thames arrears payment agreement offer then Erie Thames will proceed with the collection process and disconnection if required. No further offer will be available to the customer after disconnection.

The arrears payment agreement shall include the following terms and conditions:

a) Before entering into an arrears payment agreement Erie Thames shall apply any security deposit held on account of the customer against any electricity charges owing at the time.

b) When entering into the arrears payment agreement the customers may be required to make a down payment of up to 15%, an eligible low-income customers may be required to pay a down payment of up to 10%, of the accumulated electricity charge arrears, inclusive of any late payment charges but excluding other service charges.

c) The arrears payment agreement shall allow residential customers to pay all remaining electricity charges that are then overdue for payment, as well as the current bill amount if the customer requests to do so, after applying the security deposit and the down payment, including all electricity related service charges that have accrued to the date of the agreement, over the following periods:

    - a period of at least five months, where the total amount of the electricity charges remaining overdue for payment is less than twice the customer's average monthly bill; or
    - a period of at least ten months, where the total amount of the electricity charges remaining overdue for payment is equal to or exceeds twice the customer's average monthly billing amount.
    - In the case of an eligible low-income customer:
        - a period of at least 8 months, where the total amount of the electricity charges remaining overdue for payment is less than or equal to 2 times the customer's average monthly billing amount.
        - a period of at least 12 month where the total amount of the electricity charges remaining overdue for payment exceeds 2 times the customer's average monthly billing amount an is less than or equal to 5 times the customer's average monthly billing amount; or
        - a period of at least 16 months where the total amount of the electricity charges remaining overdue for payment exceeds 5 times the customer's average monthly billing amount.

    Erie Thames shall calculate the customer's average monthly billing amount by taking the aggregate of the total electricity charges billed to the customer in the preceding twelve months and dividing that value by twelve. If the customer has been a customer of Erie Thames for less than twelve months, the average monthly billing amount shall be based on a reasonable estimate made by Erie Thames.

d) Erie Thames has the right to cancel the arrears payment agreement if a customer defaults on more than one occasion in making payment in accordance with the arrears payment agreement or a payment on account of a current electricity charge billing, a security deposit amount due or an under-billing adjustment.

    - Erie Thames has the right to cancel the arrears payment agreement with an eligible low-income customer, if the eligible low-income customer defaults on more than two occasions in making a payment in accordance with an arrears payment agreement, or payment on account of a current electricity charge billing or under-billing adjustment.

    In both situations the defaults must occur over a period of at least 2 months before Erie Thames cancels the arrears payment agreement.

e) Erie Thames shall provide to the customer and to any third party designated by the customer, at least ten days written notice before the effective date of the cancellation.

f) Erie Thames shall provide notice of cancellation to any third party, if at the time of entering into an arrears payment agreement a customer has designated a third party to receive notice of cancellation of the arrears payment agreement.

g) Erie Thames shall accept the customer's notification of a designated third party by email or telephone communication.

h) The arrears payment agreement shall be reinstated if the customer makes payment of all amounts due pursuant to the arrears payment agreement on or before the cancellation date.

i) Erie Thames shall make available to residential electricity customers a second arrears payment agreement if the customer so requests, provided that two or more years have passed since the first arrears agreement was entered into and provided that the customer satisfied all obligations under the first arrears payment agreement.

    - Erie Thames shall allow an eligible low-income customer to enter into a subsequent arrears payment agreement if the terms described in S.2.7.5.1, 2.7.6 and 2.7.6A of the Distribution System Code has been met.

Erie Thames reserves the right to refuse to enter into another arrears payment agreement with a residential customer who failed to perform their obligations under a previous arrears payment agreement until such time as 1 year has passed since the termination of the previous agreement.

Erie Thames shall have the right to limit or disconnect service for non-payment, theft of power, failing to keep payment arrangements, and/or default of the arrears payment agreement in accordance to the provisions described in the Distribution System Code.

A collection of account charge is applicable if a representative of the utility is dispatched to the customer's premise for the purpose of collecting overdue payment of the account.

The customer shall be subject to a Board approved reconnection charge when the electricity service has been interrupted for non-payment of account.

Erie Thames shall reserve the right to make adjustments to any bill issued in error either in whole or in part.

7.1.4 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

7.1.5 REFERENCES:

The Electricity Act, 1998

Retail Settlement Code – The Ontario Energy Board

Distribution Rate Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

	Policy # ETPL-2010-7.2	Approved By: President, ETPL
		Approved Date: December 2010
	Retailer Collections	Revision: 3.1
RRAM #:		

7.2.0 PURPOSE:

This policy describes the processes to collect outstanding balances from Retailers who have signed sales agreements with consumers served by Erie Thames Powerlines distribution system and to ensure that the Retailer meets the prudential requirements based on the billing option selected and the Retailer's magnitude of financial exposure. This process also applies to collection of past due Retail settlement and market participant invoices.

7.2.1 POLICY STATEMENT:

Erie Thames Powerlines requires Retailers to pay invoices on the due date as specified in the code.

Erie Thames Powerlines reserves the right to refuse service transaction requests, requests for information, invoices or other transactions from retailers with whom Erie Thames Powerlines does not have an up-to-date service agreement and/or financial security arrangements.

Erie Thames Powerlines shall review the required level of deposit from a Retailer for customers served through Distributor Consolidated Billing on a quarterly basis as a minimum.

Erie Thames Powerlines shall immediately notify the Retailer the day after a settlement payment was due if funds were not received and work with the Retailer to remedy the situation.

Erie Thames Powerlines shall not access the funds available through the relevant security arrangement, until five business days have elapsed.

Erie Thames Powerlines shall issue to the Retailer a Notice of Payment Default prior to returning the consumer that is signed with said Retailer back to Standard Service Supply (SSS).

7.2.2 RESPONSIBILITIES:

The management of the company is responsible for ensuring that prudential monitoring and payments from a Retailer are collected within the guidelines specified in the service agreement.

7.2.3 REFERENCES:

The Electricity Act, 1998

Market Rules – The Independent Electricity Market Operator

Retail Settlement Code – The Ontario Energy Board

Distribution Rate Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

ERIE THAMES POWERLINES	Policy # ETPL-2010-7.3	Approved By: President, ETPL
		Approved Date: January 2012
	Use of Load Control Devices	Revision: 4.0
RRAM #:		

7.3.1 PURPOSE:

The purpose of this policy is to document guidelines that are consistent with the rules outlined in the Distribution System Code for management and staff when a load limiting device is installed as a means for collection of non-payment of an account rather than disconnection of the full electricity supply at a customer's premise.

7.3.2 POLICY STATEMENT:

Erie Thames at its discretion shall reserve the right to install a load control device at a customer's premise rather than disconnect the full electricity service if the customer fails to pay Erie Thames any outstanding amounts due and payable on account for the supply of electricity.

Erie Thames shall refrain from installing a load control device if notified by a Social Service Agency or Government Agency that the agency is assessing the customer for Emergency Financial Assistance for a period of 21 days after receiving the notification.

Erie Thames shall provide a written notice to the customer when the load control device is installed which will explain the operation of the device, the maximum capacity of the device, how to reset the device if the maximum capacity is exceeded and Erie Thames telephone contact number if the customer requires further information regarding the use of the device and an emergency contact number if the customer is unable to reset the device for any reason.

Erie Thames shall provide a 24 hour contact telephone number if Erie Thames installs a load limiter device that cannot be manually reset by the customer after the maximum limit is triggered so that the customer may call to have the load limiter device remotely reset.

Erie Thames shall provide written notice to a customer when a timed load interrupter is installed for non-payment explaining the effect of the device on service and a contact telephone number if the customer requires further information.

Erie Thames shall provide the following notices to a customer if Erie Thames installs a load control device for non-payment:

a) the Fire Safety Notice of the Office of the Fire Marshal; and
b) any other public safety notices or information bulletins issued by public safety authorities and provided to the distributor, which provide information to consumers respecting dangers associated with the disconnection of electricity service.

Erie Thames shall not install a load control device at a residential customer's property during the course of an arrears payment agreement, unless the agreement has been terminated in accordance to the provisions of the Distribution System Code.

Erie Thames shall remove the load control device installed at the customer's premise for the purpose of non-payment of account within two business days, from:

- the date that the residential customer entered into an arrears payment agreement;
- the date that the outstanding account was paid in full.

7.3.3 RESPONSIBILTIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debts and that the method used to collect overdue accounts complies with all applicable codes and regulations.

7.3.4 REFERENCES:

The Electricity Act, 1998

Electricity Distribution Rate Handbook – The Ontario Energy Board

Retail Settlement Code– The Ontario Energy Board

Distribution Rate Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

<table>
<tr><td rowspan="2">ERIE THAMES POWERLINES</td><td>Policy # ETPL-2010-8.0</td><td>Approved By: President
Approved Date: Jan 2012</td></tr>
<tr><td rowspan="2">Policy 8.0

DISCONNECTION/RECONNECTION OVERVIEW</td><td rowspan="2">Revision: 4</td></tr>
<tr><td>RRAM #:</td></tr>
</table>

8.0.1 PURPOSE:

The detailed policies in this set are intended to establish and document a process that specifies timing and means of notification consistent with the Electricity Act, 1998 that will provide guidance to Erie Thames management and staff when disconnecting and/or reconnecting the electrical service of a consumer.

8.0.2 POLICY STATEMENT:

Erie Thames shall follow the regulation and direction set out in the *Electricity Act (1998)*, Distribution System Code, Retail Settlement Code, and Standard Supply Service Code when implementing the disconnection and/or reconnection process.

Erie Thames will ensure that it has developed a physical and business process for reconnection of electricity supply ensuring safety and reliability as a primary requirement.

Erie Thames reserves the right to physically disconnect or limit the amount of electricity to a customer for any of the following reasons:

- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributor's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection.
- Inability of the distributor to perform planned inspections and maintenance.
- Failure of the consumer or customer to comply with a directive of a distributor that the distributor makes for purposes of meeting its licence obligations.
- The customer owes Erie Thames money for distribution services, or for a security deposit. Erie Thames shall give the customer a reasonable opportunity to provide the security deposit consistent with section 2.4.20 of the Distribution System Code.

Erie Thames shall recover from the customer responsible for the disconnection any reasonable costs associated with the disconnection, including but not limited to overdue amounts, late payment charges, reconnection fees, and any repairs to Erie Thames physical assets on the property damaged as a result of the disconnection.

Under no circumstances shall Erie Thames be held liable for any damage or loss to the customer or the customer's premises as a result of the disconnection.

8.1 Disconnection/Reconnection

8.2 Disconnection/Reconnection by Request

8.3 Safety and Reliability

8.4 Unauthorized Use of Electricity

8.0.3 DEFINITIONS:

Customer and Consumer will be understood herein as one and the same.

Disconnection means a deactivation of connection assets that result in termination of distribution services to a consumer.

Disconnect/collect trip is a visit to a customer's premises by an employee or agent of the distributor to demand payment of an outstanding amount or to shut off or limit distribution of electricity to the customer failing payment.

Eligible Low-Income Customer means a residential electricity customer who has a pre-tax household income at or below the pre-tax Low Income Cut-Off, according to Statistics Canada, plus 15%, taking into account family size and community size, as qualified by a Social Service agency or Government Agency; or a residential electricity customer who has been qualified for Emergency Financial Assistance.

Emergency Financial Assistance means any OEB approved emergency financial assistance program made available by a distributor or eligible low-income residential customers.

Good utility practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

Reconnection is when a property or premise has electrical service energized or re-established by the distributor.

Security Deposit is an amount collected by the distributor and is held by the distributor to ensure that all monies owed to the Corporation are collected at the time of the final billing. Interest payments will be applied at least annually on all cash deposits.

8.0.4 RESPONSIBILTIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt.

8.0.5 REFERENCES:

The Electricity Act, 1998

Electricity Distribution Rate Handbook – The Ontario Energy Board

Retail Settlement Code – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

ERIE THAMES POWERLINES	Policy # ETPL-2010-8.1	Approved By: President
		Approved Date: Jan. 2012
	Policy 8.1 **DISCONNECTION/RECONNECTION**	Revision: 4.0
RRAM #:		

8.1.1 PURPOSE:

This policy confirms that Erie Thames has established a process for the disconnection and/or reconnection of a property and/or premise consistent with the *Electricity Act, 1998*, and in accordance to all applicable rules and timelines as outlined in the Distribution System Code.

8.1.2. POLICY STATEMENT:

Erie Thames shall comply with all applicable regulation as defined in the Distribution System Code, Retail Settlement Code and Standard Supply Service Code when disconnection and/or reconnection of a customer's electrical service are required.

Erie Thames will ensure that it has developed a physical and business process for disconnection and/or reconnection ensuring safety and reliability as a primary requirement.

Erie Thames shall treat all customers in a non-discriminatory fashion when disconnecting and/or reconnecting an electrical service.

Erie Thames shall, pursuant to S.31 of the *Electricity Act*, provide reasonable notice of disconnection to residential customers if Erie Thames intends to disconnect the property for non-payment of account. The disconnection notice shall include, at a minimum, the information outlined in S.4.2.2 of the Distribution System Code.

Erie Thames shall provide, prior to disconnecting a property for non-payment, the Fire Safety Notice of the Office of the Fire Marshall; and any other public safety notices or information bulletins issued by public safety authorities to Erie Thames, which provides information to customers respecting dangers associated with the disconnection of electricity services.

Erie Thames shall not send or deliver the disconnection notice for non-payment in the same envelope as the customer's bill.

Erie Thames shall apply the rules described in S.2.6 of the Distribution System Code when determining the computation of time relating to bill issuance and application of payments.

Erie Thames shall follow the rules defined in S.4.2.3 of the Distributions System Code when determining the date a disconnection notice is deemed to have been received by a customer.

Erie Thames will not disconnect a customer until the minimum notice period defined in S.4.2.3 of the Distribution System Code has elapsed.

Erie Thames shall, at the request of a residential customer, send a copy of any disconnection notice issued to the customer for non-payment to a third party designated by the customer for that purpose. Provided that the request is made no later than the last day of the applicable minimum notice period as defined in S.4.2.3 of the Distribution Code as:

a) 60 days from the date on which the disconnection notice is received by the customer, in the case of a residential customer that has provided the distributor with documentation from a physician confirming that disconnection poses a risk of significant adverse effects on the physical health of the customer or on the physical health of the customer's spouse, dependent family member or other person that regularly resides with the customer; or

(b) 10 days from the date on which the disconnection notice is received, in all other cases.

Erie Thames shall notify the third party that the third party is not responsible for the payment of any charges for the provision of electricity service in relation to the customer's property, unless otherwise agreed by Erie Thames.

S.2.6.4 and S.2.6.7 shall apply when determining the date of receipt of the disconnection notice by the third party, Erie Thames may modify the context if require.

Erie Thames shall at the request of a residential customer, at any time prior to disconnection, provide a copy of any future notice of disconnection to a third party designated by the customer. Such requests made by a residential customer shall be accepted by electronic mail (email) or telephone communications.

Erie Thames shall issue a new disconnection notice if a customer's electrical service was not disconnected 10 days from the date that the original disconnection notice was deemed to have been received by the customer or 60 days if a residential customer has provided documentation from a physician that disconnection poses a risk of significant adverse effects on the physical health of the customer or the customers spouse, dependent family member or other person that regularly resides with the customer.

Erie Thames shall determine the date the disconnection notice was received by the customer in accordance to S.4.2.3.1 of the Distribution System Code.

Erie Thames shall attempt to contact a residential customer either by telephone or in person 48 hours prior to the scheduled date of disconnection. At such time Erie Thames shall advise the customer:

- of the scheduled date of disconnection;
- if the disconnection will take place whether or not the customer is at the premises;
- if the disconnection will occur without attendance at the customer's premise;
- that payment can be made by credit card or any other form of payment that will be acceptable by Erie Thames and during what hours the payment must be received that would prevent the execution of the disconnection;
- that if Erie Thames attends the property to execute the disconnection payment will only be accepted by credit card issued by a financial institution, unless Erie Thames agrees to accept other forms of payment at that time;
- if the customer is eligible and if Erie Thames is prepared to enter into a Board-prescribed arrears payment program. Further information regarding the arrears payment program is detailed in S.2.7 of the Distribution System Code, and Erie Thames Policy 7.1 Customer Collections;
- if there are any additional options that Erie Thames can offer the customer that will avoid the execution of the disconnection.

Erie Thames shall post a copy of the disconnection notice for non-payment in a conspicuous place on or in the building promptly after issuance of the notice, if a disconnection notice is issued to a multi-unit or master-metered building.

Erie Thames shall suspend any disconnection action for a period of 21 days from the date of notification from a registered charity, government agency or social service agency that is determining if the residential customer is eligible to receive bill payment assistance, provided the notification is received within 10 days from the date on which the disconnection notice was received by the customer.

Where a residential customer requested prior to the issuance of the disconnection notice that a copy of any disconnection notice be provided to a third party, Erie Thames shall suspend any disconnection action for 21 days from the date of notification that the third party is attempting to arrange assistance with the bill payment, provided the notification is received within 10 days from the date the disconnection notice was received by the customer. If the registered charity, government agency, social service agency or any other third party decides the customer is not eligible and/or will not proceed with bill payment assistance Erie Thames will continue with the disconnection process. If 11 days has not expired since the previous disconnection notice a new disconnection notice will not be issue. Erie Thames will make every effort to contact the customer prior to executing the disconnection.

Erie Thames shall have the right to limit or discontinue service without further notification in accordance with a court order or for emergency, safety or system reliability reasons.

Erie Thames shall have the right to limit or discontinue service for non-payment of a security deposit from customers that have defaulted on payment arrangements.

Erie Thames shall have the right to refuse the reconnection if there are any outstanding amounts owed by the customer.

Erie Thames shall have the right to disconnect and/or refuse the reconnection if the service is found to have an adverse effect on the safety and/or reliability of the distribution system.

Erie Thames shall have the right to disconnect and/or refuse the reconnection of the electrical service of a customer if it is found as an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.

Erie Thames shall have the right to disconnect and/or refuse the reconnection of a customer for a material decrease in the efficiency of Erie Thames distribution system and/or an adverse effect on the quality of distribution services received by an existing connection.

Erie Thames shall have the right to disconnect a customer if Erie Thames is cannot perform planned inspections and maintenance when required.

Erie Thames has the right to disconnect and/or refuse to reconnect if a customer fails to comply with a directive of Erie Thames made for the purpose of meeting Erie Thames distribution licence obligations.

Erie Thames shall insist that electrical services that have been disconnected for six (6) or more months have an inspection certificate from the Electrical Safety Authority prior to reconnection. Notwithstanding, Erie Thames reserves the right to require, an Electrical Safety Authority inspection certificate at any time prior to reconnection at the expense of the customer.

Erie Thames shall insist that a responsible representative of the property be present in order for reconnection of service to be established.

8.1.3 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt and any adverse effects on the reliability and safety of the distribution system.

8.1.4 REFERENCES:

The Electricity Act, 1998

Retail Settlement Code – The Ontario Energy Board

Distribution Rate Handbook – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Electricity Gas and Inspection Act – Government of Canada

Condition of Service – Erie Thames Powerlines Corporation

ERIE THAMES POWERLINES	Policy # ETPL-2010-8.2	Approved By: President Approved Date: Jan 2012
RRAM #:	**Policy 8.2** **DISCONNECTION/RECONNECTION BY REQUEST**	Revision: 4.0

8.2.1 PURPOSE:

This policy confirms that Erie Thames has established a process for the disconnection and/or reconnection of an electrical service when requested by a customer and/or an authorized authority.

8.2.2 POLICY STATEMENT:

Erie Thames shall respond to a customer's request for a disconnection and reconnection of an electrical service in a prompt and efficient manner.

Erie Thames shall disconnect a Customer immediately without notice, in accordance with a court order, a request by a fire department, Police, Electrical Safety Authority or for emergency, public safety (including potential for loss of life or limb), system reliability reasons or in order to inspect, maintain, repair, alter, remove, replace or disconnect wires or other facilities used to distribute electricity or where there is energy diversion, fraud or abuse on the part of the Customer.

Erie Thames shall have the right to refuse reconnection of the customer's electrical service if:

a) there is an outstanding amount of money owed by the consumer;
b) the connection is found to have an adverse effect on the safety and/or reliability of the distribution system;
c) the failure of the customer and/or their agent to obtain approval of the Electrical Safety Authority, if required.

Erie Thames requires that the Customer obtain the approval of the Electrical Safety Authority prior to Erie Thames reconnecting the electrical service:

a) where the service has been disconnected for a period of six (6) or more months;
b) where Erie Thames has reason to believe that the wiring may have been damaged or altered;
c) where service was disconnected for modification of Customer wiring;
d) where the service was disconnected as a result of an adverse effect on the reliability and safety of the Distribution system; or
e) where it is a requirement of the Electrical Safety Code.

Erie Thames shall insist that a responsible representative of the property be present when electrical service is energized or reconnected.

8.2.3 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the corporation is protected from undue risk of bad debt and any adverse effects on the reliability and safety of Erie Thames Powerlines distribution system.

8.2.4 REFERENCES:

The Electricity Act, 1998
Retail Settlement Code – The Ontario Energy Board
Distribution System Code – The Ontario Energy Board
Condition of Service – Erie Thames Powerlines Corporation

8.3.1 PURPOSE:

This policy confirms that Erie Thames has established a process for ensuring the safety and reliability of Erie Thames Powerlines distribution system.

8.3.2 POLICY STATEMENT:

Erie Thames shall respond to and take reasonable steps to investigate all consumer power quality complaints and report to the consumer on the results of the investigation.

Erie Thames may direct a consumer connected to its distribution system to take corrective or preventive action on the consumer's electric system when there is a direct hazard to the public or the consumer is causing or could cause adverse effects on the reliability of Erie Thames's distribution system.

Erie Thames may require that any consumer conditions that adversely affect the distribution system be corrected immediately by the consumer and at the consumer's expense.

Erie Thames shall have the right to disconnect a customer from the distribution system if the customer does not remedy the situation as directed by Erie Thames within the time period specified by Erie Thames. Erie Thames shall provide notice of disconnection to the customer either by personal service, prepaid mail or by posting notice on the property in a conspicuous place.

Erie Thames shall have the right to disconnect a customer without notice if the service causes safety or reliability risk to Erie Thames distribution system.

Erie Thames shall insist that electrical services that have been disconnected for six (6) or more months have an inspection certificate from the Electrical Safety Authority prior to reconnection. Notwithstanding Erie Thames reserves the right to require an Electrical Safety Authority certificate at any time prior to reconnection at the customer expense.

Erie Thames shall have the right to refuse the reconnection of an electrical service to their distribution system if the connection is found to have an adverse effect on the safety and/or reliability of the system.

Erie Thames shall insist that a responsible representative of the property be present when electrical service is energized or reconnected.

8.3.3 RESPONSIBILITIES:

The management of the company is responsible for ensuring that the service quality of the distribution system is safe and reliable.

8.3.4 REFERENCES:

The Electricity Act, 1998

Retail Settlement Code – The Ontario Energy Board

Distribution Rate Handbook – The Ontario Energy Board

Condition of Service – Erie Thames Powerlines Corporation

<table>
<tr><td rowspan="2">ERIE THAMES POWERLINES</td><td>Policy # ETPL-2010-8.4</td><td>Approved By: President
Approved Date:</td></tr>
<tr><td>Policy 8.4.0
UNATHORIZED USE OF ELECTRICITY</td><td rowspan="2">Revision: 1</td></tr>
<tr><td>RRAM #:</td><td></td></tr>
</table>

8.4.1 PURPOSE:

This policy confirms that Erie Thames has established a process that management and staff can follow if it is discovered that there is unauthorized use of electricity.

8.4.2 POLICY STATEMENT:

Erie Thames shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, Erie Thames shall notify, if appropriate, Measurement Canada, the Electrical Safety Authority, police officials, retailers that service consumers affected by the unauthorized energy use, or other entities.

Erie Thames shall monitor losses and unaccounted for energy use on an annual basis to detect any upward trends.

Erie Thames may recover from the parties responsible for the unauthorized energy use all energy and other applicable charges incurred by Erie Thames arising from the unauthorized energy use, including but not limited to inspections, administration fees and repair costs.

8.4.3 RESPONSIBILITIES:

The management of the company is responsible for monitoring losses and unaccounted energy use.

8.4.4 REFERENCES:

The Electricity Act, 1998

Retail Settlement Code – The Ontario Energy Board

Distribution System Code – The Ontario Energy Board

Conditions of Service – Erie Thames Powerlines Corporation

Appendix 4

Summary of Changes in Erie Thames
Condition of Services

January 2012:

1.5.1 Contact Information
Updated Erie Thames contact information

2.1.7 Contracts
Opening and Closing of Accounts
Landlord and Tenant Agreements
This section has been included to reflect the amendments to the Distribution System Code regarding:

- customer acceptance of responsibility for account charges when opening an electricity account
- opening an account at the request of a third party
- agreements with landlord/owner for accountability for electricity to rental units when the units are not occupied by a tenant.

2.2 Disconnection
This section has been updated to reflect the amendments to the Distribution System Code.

2.2.1 Load Limiter Devices
This section has been added to document Erie Thames use of load limiter devices.

2.3.7.3.2 Smart Meter
This section has been added.

2.4.3 Deposits
This section has been updated to reflect the amendments to the Distribution System Code.

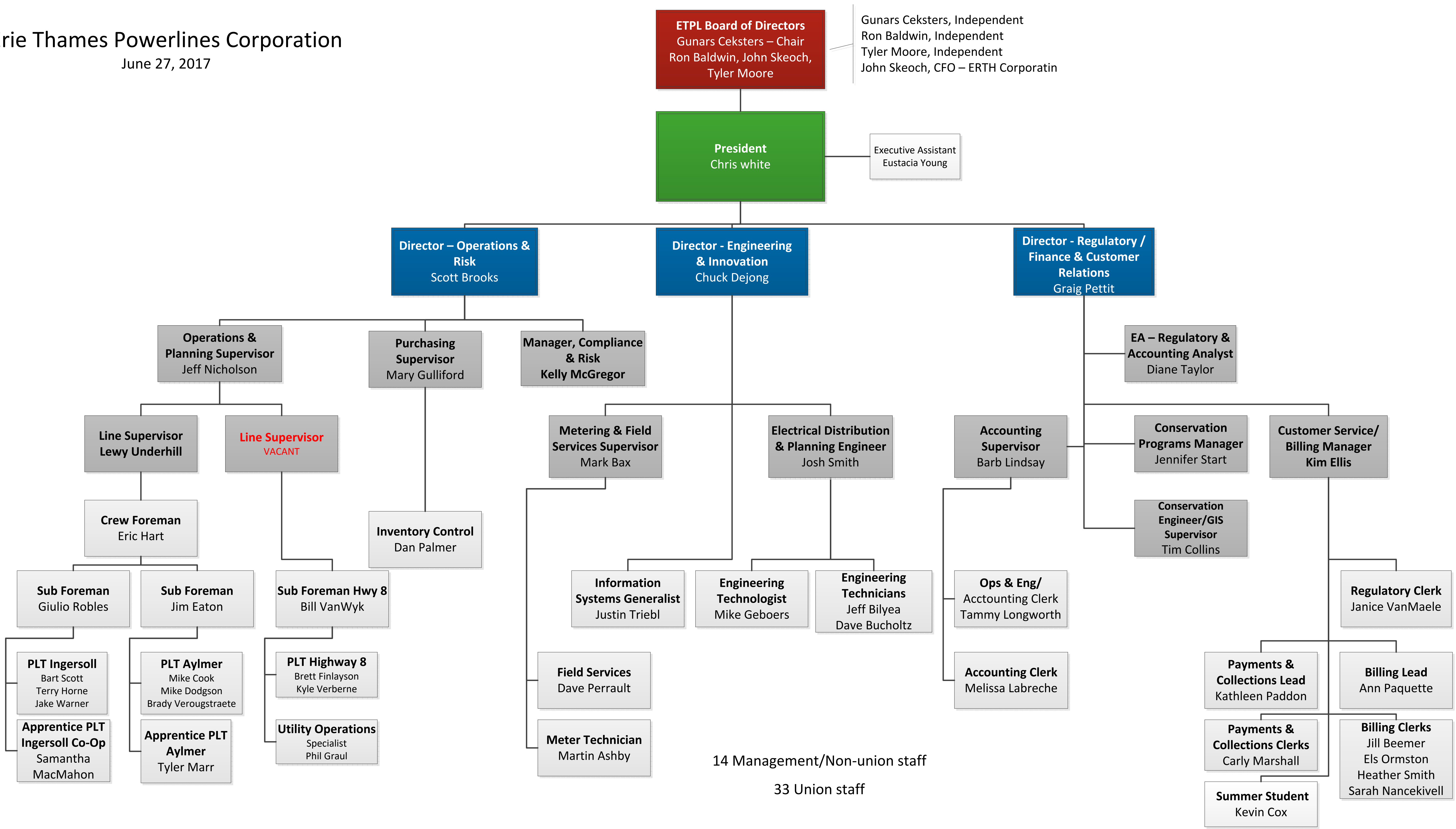
Appendix 3 – Policies – Erie Thames updated policies to reflect the amendments to the Distribution System Code and Standard Supply Service Code

Attachment 5 (of 15):

1-E Organizational Chart

Erie Thames Powerlines Corporation

June 27, 2017



Attachment 6 (of 15):

1-F 2014 Customer Survey Findings & Recommendations

2014 Customer Capital Investment Survey Findings and Recommendations

It is understood that a very small group of our customers have responded to this survey, and therefore although the information provide is valuable we need to determine the merit of the comments provided by the customers, before expending time and funds on each.

Finding

897 customers or 5% of our customers completed our survey, 825 being residential customers, 9 are commercial customers, and 28 have residential and commercial accounts with Erie Thames Powerlines.

Reliability and pricing remains the major concerns of our surveyed customers, with 62% of saying that the total hydro bill is the most important aspect of their electricity supply, and 30% say that reliability is the most important.

Customers were informed that our primary focus of construction and maintenance work is to maintain or improve reliability of the supply of electricity to them, 77% felt that our existing level of reliability is acceptable, where 18% stated that would be will to tolerate an increase in outages if it meant a decrease in their monthly hydro bill. Our customers also did not support the idea if implementing a program to start burying hydro lines if it required an increase in their bills.

In regards to web-based outage map system that would be available to our customers, 50% of respondents felt ETPL should focus on decreasing the frequency and length of outages rather than developing a web-based outage map, and 45% felt that Erie Thames Powerlines should not invest in a web-based outage map. Our customers also felt very strongly that although they feel ETPL should be active on social media they would not support the increased cost of manning the service 24 hours per day, 7 days a week.

With regards to notification of planned outages, 88% of those surveyed felt ETPL already made all necessary efforts to inform them in advance of the outage.

Conservation appears to still be the main concept with our customers to reduce usage. 31% of the customers surveyed are considering the purchase of storage systems, Solar or wind generation in the next 5 years to reduce consumption from the grid, and 89% stated they are no considering the purchase of an electric vehicle in that same time frame.

Recommendation

Although some of our customers have a reasonable understanding of the services available to them on our website we need have a educational blitz to our customers of what is available on our website for their use and electronic delivery of bills. The survey shows us that 75% of customers surveyed are not aware that our website provides the following information:

- Energy saving tips and advise
- Time-of-use rates,
- Electric usage of their account
- Ability to order meter reading for the purpose of moving into and out of a property
- Availability of Smart Meter data

Our survey shows that 79% of customers will switch to electronic billing, if we offer them a small monthly discount. We need to calculate the savings to us and then what we could offer to the customers, and again blitz the customers with this info.

On average approximately 1/3 of the customer's surveyed plan on purchasing a major high usage appliance (refrigerators, freezers, dehumidifiers, and hot tubs) within the next 5 years. From a CDM view is there a program that we could promote that encourage our customers the purpose efficient appliances.

We had many customers comment that they would like to have contact and communication with us via email. Another blitz of our customers to obtain email addresses would be beneficial.

Attachment 7 (of 15):

1-G 2016 Customer Survey Findings & Recommendations

2016 Customer Survey

Findings & Recommendations

The following document details the results of the 2016 customer survey used to collect data from customers regarding their satisfaction, knowledge and preferences.

COMPLETED:
January 2016

Contents

2016 Customer Satisfaction Survey Findings and Recommendations

Although many of the findings and recommendations could be of value we also need to recognise that this information comes from a very small sampling of our customers, and therefore must determine the merit of suggestions provided by customer, before expending a large amount of time and funds on each.

Findings

We had 1136 customers take the survey in 2016 as compared to 897 in our last Customer Survey.
We found that the amount of responses jumped substantially when we contacted the customers via email. We did not use email for the previous survey.
This survey was used as both an education tool, providing customers with average $ that remain with ETPL, as well as what part of the provincial electrical system that ETPL actually has control over, and a data collection tool, to measure satisfaction, concern, and knowledge.

The average residential customer pays about $200 a month for electricity of which $32 or approximately 16% goes to Erie Thames Powerlines. The remainder of the electricity portion of your bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies. Before this survey, how familiar were you with the amount of your electricity bill that went to Erie Thames Powerlines?		
Answer Options	Response Percent	Response Count
Very familiar	7.7%	87
Somewhat familiar	17.1%	192
Not very familiar	27.8%	312
Not familiar at all	45.7%	513
Don't know	1.1%	12
N/A	0.6%	7
	answered question	1123
	skipped question	13

As with our previous survey, on a whole it tells us that most of our customers are quite happy with the service that is provided to them by ETPL, and their focus still remains on low costs and reliability.

Overall, how satisfied are you with the service you receive from Erie Thames Powerlines?		
Answer Options	Response Percent	Response Count
100%	51.1%	580
75%	38.1%	433
50%	7.2%	82
25%	2.6%	29
0%	1.1%	12
	answered question	1136
	skipped question	0

What is the most important aspect of your electricity supply?		
Answer Options	Response Percent	Response Count
Total price	49.7%	550
Reliability	44.5%	492
Customer service	2.7%	30
Conservation programs	3.1%	34
	answered question	1106
	skipped question	30

When asking our customer what we could do to improve our service to them, 680 customers replied, they identified the following areas:

52% lower costs
18% Billing/Collections, Call Centre
16% outages
6% operations issues
4% water, sewer or streetlight issues
3% Website
2% Conservation

We explained how we currently contact customers regarding planned outages and asked for their preferred form on communication in this situation. An overwhelming 69% of the 173 customers that responded asked to be contacted by **email**. The remainder feel that our current forms are sufficient.

Recommendations

The survey does show us a few areas where we could improve. Firstly we could attempt to educate our customers on our roll in the provincial electrical system, and what specifically we are in control of, i.e. the distribution systems within the municipalities that we serve, but not transmission, generation or rates and other charges.

As you may know, electricity from generating stations located around the province travels over transmissions lines on those large transmissions towers. However, what we want to talk about today is the electricity distribution system in your community that is operated by Erie Thames Powerlines. Their system consists of hydro poles and wires, underground cables, transformer boxes on lawns, substations and smart meters. How familiar are you with Erie Thames Powerlines, which operates the electricity distribution system in your community?		
Answer Options	Response Percent	Response Count
Very familiar	19.2%	218
Somewhat familiar	49.2%	559
Not very familiar	22.9%	260

Not familiar at all	7.0%	79
Don't know	1.2%	14
N/A	0.5%	6
	answered question	1136
	skipped question	0

This survey shows that our customers want to see an improvement in reliability of service, fewer numbers of outages, less voltage fluctuations, and increase speed of restoring power, when outages occur. I feel these results would improve once Hydro One is able to correct transmission issue to some of our areas. If possible we should also educate the customers on what it takes to find the outage and then move the repairing and restoring the power.
We were able to inform customers that only 16% of what they pay each month for electricity actually stays with ETPL, and the remainder of their bill moves on to other bodies, and therefore they are costs ETPL cannot control.

Another area that ETPL needs to attempt to improve and/or educate customers is with our billing. We only scored an average of 63% on accuracy, payment options, understandability, timely delivery of bills, and communication. Once again education of the customer to understand that we are mandated to provide line items as they appear, and timing of when bills can actually be produced would help alleviate some of their concerns. Other questions we need to ask are:

- Can we improve on our billing accuracy
- Is there any other payment options we can offer
- Can the new bill format be improved on
- How can we deliver bills quicker to the customer
- How can we improve communication with our customers

We may find that we are providing the best service; however a review of the above items would only benefit the customers and ETPL. I feel that there are several actions that can be taken to improve on many of these issues:

▪ ***Customer Education:***

- Water/Sewer and streetlights are not owned, operated or repaired by ETPL. We must make it clear that we do bill for these services and will take repair calls, however we ultimately have no control over the rates charged for these services or when and how they are repaired.
- We need to not only put our website to more use, via notifying customers and providing information on the site but possibly testing all links, as we did have a few comments regarding the ability to move about on the site and finding the information customers are looking for.
- In areas where our customers seem to suffer more frequent and prolonged outages due to our supply from Hydro One, just ensure that customers understand where the issues lies, as well as possibly the difficulties in finding the problem in such areas.
- Blitz the customers for email address' and updated contact information, so that we can then begin sending out educational info regarding, payment options, billing and collections process' and why we need to have the billing schedule we do, as well as providing customers with outage info.

- Conservation topics – via, bill stuffers, emails, social media.
- Payment options – blitz the customers with the payment options and plans available
- E-care ability, what the customers can see, benefits of information provided on site
- Online billing and other services provided

▪ ***Internal checks and processes***

- Website – we did have a few comments about our website not being user friendly, or not working on all platforms. Customers are also looking more up to date info.
- Do we contact customers when their water usage spikes? Does our VEE process need to be updated
- Late payment calls, do we call customers that have never been late before, and do we call 2-4 days after due date.
- What are our billing accuracy rates? Are they within a tolerable rate, what is cause of billing adjustments?
- Can we or have we compared our bill format to other utilities, is there anything we can do to improve our bill format so that our customers can understand it easily.
- Should a schedule be set up for sending out communications to customers, billing, CDM ….
- It would appear that customers are looking for more frequent updates when there are outages. I would suggest we start posting more regularly to social media during outages, as well as, if possible, using email for planned outages and stating that customers should watch our social media feeds for current updates during time of outage.
- Do we need to continue to use the costly newspaper ads to inform customers of planned outages
- Ensure non-customers (i.e. apartment bldgs.) are notified of outages, hand delivered notification may be the most effective.

As stated previously these actions would be responding to all comments received from our customers and may not necessarily improve our services that we provide.

Attachment 8 (of 15):

1-H 2015 Scorecard and MD&A

Scorecard - Erie Thames Powerlines Corporation

9/29/2016

										Target	
Performance Outcomes	**Performance Categories**	**Measures**		**2011**	**2012**	**2013**	**2014**	**2015**	**Trend**	**Industry**	**Distributor**
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		99.30%	98.80%	98.80%	99.40%	98.40%		90.00%	
		Scheduled Appointments Met On Time		98.10%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		98.10%	94.60%	95.80%	95.50%	98.40%		65.00%	
	Customer Satisfaction	First Contact Resolution					99.7%	99.85			
		Billing Accuracy					99.85%	99.46%		98.00%	
		Customer Satisfaction Survey Results					100 %	89%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness						83.40%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	C	NI	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.53	1.47	0.41	0.59	0.73			0.99
		Average Number of Times that Power to a Customer is Interrupted [2]		0.75	0.31	0.20	0.30	0.48			0.41
	Asset Management	Distribution System Plan Implementation Progress					In Progress	94%			
	Cost Control	Efficiency Assessment			4	3	3	3			
		Total Cost per Customer [3]		$634	$564	$610	$631	$656			
		Total Cost per Km of Line [3]		$35,056	$30,891	$32,792	$33,707	$34,342			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Cumulative Energy Savings [4]						18.75%			27.63 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		25.00%	100.00%			100.00%			
		New Micro-embedded Generation Facilities Connected On Time				100.00%	92.86%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.67	0.78	0.75	0.58	0.85			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.06	1.23	1.19	1.05	1.59			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.68%	9.12%	9.12%	9.12%	9.12%			
			Achieved	4.41%	8.43%	11.80%	10.63%	9.39%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

Legend:
5-year trend: up, down, flat
Current year: target met, target not met

Appendix A – 2015 Scorecard Management Discussion and Analysis ("2015 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2015 Scorecard MD&A:
http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

- In 2015, Erie Thames Powerlines performed exceptionally well with respect to its targets and improved many of its results when compared to its 2014 performance. Bad weather and increasing failure rates for aging distribution assets resulted in a slight decrease in reliability measures for 2015. However, Erie Thames remains well under the former mandated targets and continues to provide excellent reliability for its customers that is significantly better than the industry average.
- Erie Thames undertook its first customer satisfaction survey in 2015. Our customers (that completed the survey) were all extremely satisfied with Erie Thames' performance. It is important to note that a comparison with the 2014 should not be made given that the 2014 survey focused solely on the DSP and not general customer satisfaction.
- Erie Thames Powerlines monitors its results with respect to the measures reported on the scorecard, and is continually seeking to improve upon its performance in order to improve the service provided to its customers.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2015 Erie Thames Powerlines connected 98.4% of its 189 new residential and small businesses to the distribution system within the required 5 day window that has been determined by the Ontario Energy Board. This result is not material different that previous years as Erie Thames continues its solid performance over the past five years with this measure. Given the relatively small number of new connections annually that are dealt with by Erie Thames staff it is expected that the current level of performance will be easily maintained until such a time that there is a significant increase in the number of new connections required.

- **Scheduled Appointments Met On Time**

Erie Thames Powerlines scheduled 12 appointments with its customers in 2015 to complete work requested by customers. Consistent with the prior year, the utility met 100% of these appointments on time, which significantly exceeds the industry target of 90%.

- **Telephone Calls Answered On Time**

In 2015 Erie Thames Powerlines customer service staff received approximately 27,545 calls and achieved a service level of 98.4% in answering those calls within 30 seconds, while only 1.6% of calls received were abandoned prior to customers speaking with an agent. Both of these results exceed the Ontario Energy Board's required level of service and are consistent with the performance of the call center in previous years. Erie Thames will look to continue with its excellent call center performance in 2016 and strive to reduce the number of abandoned calls experienced by our customers.

Customer Satisfaction

- **First Contact Resolution**

Specific customer satisfaction measurements have not been previously defined across the industry. The Ontario Energy Board (OEB) instructed all electricity distributors to review and develop measurements in these areas and begin tracking by July 1, 2015 so that information can be reported in 2016. The OEB plans to review information provided by electricity distributors over the next few years and implement a commonly defined measure for these areas in the future. As a result, each electricity distributor may have different measurements of performance until such time as the OEB provides specific direction regarding a commonly defined measure.

First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors.

For Erie Thames Powerlines, First Contact Resolution was measured based upon actual calls received from customers with respect to the same or similar issue and calculated this number as a percentage of all customer contacts received that resulted in the generation of an issue and for which a service order was created. The result was that 99.8% of customers' issues were dealt with on first contact. Erie Thames continues to review its tracking of this measure and will adjust how the data is compiled and expects that its 2016 performance will decrease due to more effective tracking of this measure.

- **Billing Accuracy**

Until July 2015 a specific measurement of billing accuracy had not been previously defined across the industry. After consultation with some electricity distributors, the Ontario Energy Board (OEB) has prescribed a measurement of billing accuracy which must be used by all electricity distributors effective October 1, 2015.

For the year 2015 Erie Thames Powerlines issued 224,578 bills and achieved a billing accuracy of 99.46%. This compares favourably to the prescribed OEB target of 98%.

Erie Thames Powerlines continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

The Ontario Energy Board (OEB) introduced the Customer Satisfaction Survey Results measure beginning in 2013. At a minimum, electricity distributors are required to measure and report a customer satisfaction result at least every other year. At this time the Ontario Energy Board is allowing electricity distributors to use their own discretion as to how they implement this measure.

Erie Thames undertook its first customer satisfaction survey in 2015 and determined that its customers were 89% satisfied with its performance on a variety of measures. Erie Thames Powerlines customers indicated that improvements can be made to better communicate planned outages, improvements can also be made with respect to billing with educating our customers with respect to options available to them for payments, delivery of bills and general understanding of bills, finally a few customers felt our website needed to be updated however it is not clear if they have visited the newly launched website that went live shortly before the survey.

Safety

- **Public Safety**

The Ontario Energy Board (OEB) introduced the Safety measure in 2015. This measure looks at safety from a customers' point of view as safety of the distribution system is a high priority. The Safety measure is generated by the Electrical Safety Authority (ESA) and includes three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04, and the Serious Electrical Incident Index.

  - **Component A – Public Awareness of Electrical Safety**

In 2015 Erie Thames Powerlines completed its survey of its customers with respect to public awareness of Electrical Safety. Erie Thames utilized a third party agency to survey its customers and ensure that and accurate sampling of its population was achieved. The results of this survey found that 83.4% of Erie Thames customers have strong awareness of electrical safety. Erie Thames will continue to work within its communities to ensure that this metric continues to improve in the future.

- ### Component B – Compliance with Ontario Regulation 22/04

  In 2014 and 2015, Erie Thames Powerlines was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety, and adherence to company procedures & policies. Ontario Regulation 22/04 - *Electrical Distribution Safety* establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service.

  In 2013, Erie Thames Powerlines was given a score of Needs Improvement in compliance with Ontario Regulation 22/04 (Electrical Distribution Safety). This score was given due to an interpretation issue with respect to the ESA requirement to ground utilizing a metal guard. The ESA resolved with Erie Thames Powerlines that the grounding was not required with the specifications used by Erie Thames but the resolution was not obtained until after the 2013 results were published.

- ### Component C – Serious Electrical Incident Index

  Erie Thames Powerlines has no reported serious incidents from 2010 to 2015. Erie Thames continues to be committed to safety in an effort to ensure this trend continues.

System Reliability

- ### Average Number of Hours that Power to a Customer is Interrupted

Erie Thames Powerlines had a slight increase in 2015 of the number of hours that power to a customer is interrupted. The number of outage hours is still on the low side of the former target range provided by the Ontario Energy Board. Erie Thames results fell within the new LDC specific requirement of 0.99 for SAIDI however there has been an increase over the past two years that needs to be managed to ensure the trending is not a systemic issue within ETPL's distribution system as opposed to significant one time anomalous events.

Erie Thames Powerlines continues to view reliability of electricity service as a high priority for its customers and as such conducts a vegetation management program that ensures the whole system is trimmed every three years. Similarly Erie Thames is dedicated to upgrading its assets to 27.6 kV in order to reduce its reliance on substations and thereby ensure that its reliability continue to be above average as aging stations are retired. This, combined with the Erie Thames Powerlines' senior management team's commitment to review the worst performing feeders on a quarterly basis in order to potentially improve reliability, will ensure customers continue to receive excellent reliability from Erie Thames' system.

- **Average Number of Times that Power to a Customer is Interrupted**

Erie Thames average number of times that power to a customer is interrupted has increased slightly but is still at the low end of the former range of acceptable results set by the Ontario Energy Board. However, when compared to the new distributor specific target of 0.41 Erie Thames was marginally above the target and therefore is showing that this target is not met. While the result is portrayed as a target that is not met the results that Erie Thames has achieved with respect to SAIFI are still excellent results and are well below the industry average results for 2015 of 1.08 as calculated utilizing yearbook data.

Erie Thames staff is mindful of the aging assets that make up its distribution system and will continue to monitor its assets and outages to ensure that the capital spend is appropriate to ensure that the number of outages does not continue to escalate to a point that it becomes an issue.

Asset Management

- **Distribution System Plan Implementation Progress**

Erie Thames Powerlines has substantively completed its DSP and while it has not been filed with OEB as part of a COS filing it has become the guiding document for tracking our capital spend beginning in 2015. Erie Thames has detailed its 5 year spend and projects and has measured itself on an annual basis with respect to the actual spending level versus its plan. In 2015 Erie Thames spent approximately 94% of the dollars planned to be invested into its distribution system.

Erie Thames will continue to file percentage completion annually as part of its RRR scorecard.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In 2015, for the second year in a row, Erie Thames Powerlines was placed in Group 3, where a Group 3 distributor is defined as having actual costs within +/- 10 percent of predicted costs. Group 3 is considered "average efficiency" – in other words, Erie Thames Powerlines costs are within the average cost range for distributors in the Province of Ontario. In 2015, 45% (33 distributors) of the Ontario distributors were ranked as "average efficiency"; 29% were ranked as "more efficient"; 26% were ranked as "least efficient. Although Erie Thames Powerlines forward looking goal is to advance to the "more efficient" group, management's expectation is that efficiency performance will not decline.

- **Total Cost per Customer**

Total cost per customer is calculated as the sum of Erie Thames Powerlines capital and operating costs and dividing this cost figure by the total number of customers that Erie Thames serves. The cost performance result for 2015 is $656 /customer which is a 3.9% increase over 2014.

Erie Thames Powerlines Total Cost per Customer has increased by only 3.5% since 2010 despite the increase in 2015 over 2014. Similar to most distributors in the province, Erie Thames Powerlines has experienced increases in its total costs required to deliver quality and reliable services to customers. Province wide programs such as Time of Use pricing, growth in wage and benefits costs for our employees, as well as investments in new information systems technology and the renewal and growth of the distribution system, have all contributed to increased operating and capital costs. Despite these changes Erie Thames has succeeded in keeping its cost of operations relatively flat and in doing so has been able to change its efficiency rating from 4 to 3. Erie Thames Powerlines will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that Erie Thames Powerlines operates to serve its customers. Erie Thames 2015 rate is $34,342 per Km of line, a 1.9% increase over 2014. However since 2010 the cost per kilometer of line has reduced by 2.0% due to the same cost drivers as detailed in the total cost per customer and a relatively static number of kilometers of line required to service Erie Thames customers between 2014 and 2015. This increase in cost per kilometers of line from 2010 to 2015 is due in part to an increase in assets but can be directly attributable to the implementation of GIS and a more accurate recording of its assets.

Conservation & Demand Management

- **Net Cumulative Energy Savings (Percent of target achieved)**

Erie Thames Powerlines is pleased that it is progressing well towards achieving its target of 27.63 GWH in the 2015-2020 CDM framework. While our results in 2015 are not exactly one years' worth of saving prorated on a linear basis it is important to note that Erie Thames is in fact ahead of the results it had expected to achieve in the first year as filed in its official plan with the IESO.

Erie Thames is confident that it has the programs in place and the targeted achievable potential to reach its lofty savings goal by the end of the framework.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

  Erie Thames Powerlines is pleased to report that it completed all of its connection impact assessments on time in 2015.

- **New Micro-embedded Generation Facilities Connected On Time**

  In 2015, Erie Thames Powerlines connected 5 new micro-embedded generation facilities (microFIT projects of less than 10 kW) 100% of time within the prescribed time frame of five business days. The minimum acceptable performance level for this measure is 90% of the time. Erie Thames Powerlines works closely with its customers and their contractors to tackle any connection issues to ensure the project is connected on time.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being “liquid”. The higher the number, the more “liquid” and the larger the margin of safety to cover the company’s short-term debts and financial obligations.

  Erie Thames Powerlines current ratio improved from 0.58 to 0.85 in 2015 as a result of restructuring its debt which moved it from current to long term and in May of 2015 Erie Thames also began to recover a large amount of regulatory assets in 2015 which managed to significantly improve cash flow. Erie Thames will continue to monitor its liquidity to ensure that it continues to improve in order to meet its financial obligations.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring. Erie Thames Powerlines maintains a debt to equity structure that is in line with the deemed 60% to 40% capital mix as set out by the OEB – this is demonstrated by the 2015 debt to equity ratio of 1.59.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  Erie Thames Powerlines current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.12%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**

  Erie Thames Powerlines return achieved in 2015 was 9.39%, which is well within the +/-3% range allowed by the OEB. The average return over the past 3 years was 10.6% which is also well within return included in Erie Thames Powerlines approved rates. Erie Thames Powerlines achieved returns higher than the deemed rate in 2013 and 2014 mainly due to higher revenue than forecast, as a result of increased energy consumption; and effective control of its operating costs.

Note to Readers of 2015 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgment on the reporting date of the performance scorecard, and could be markedly different in the future.

Attachment 9 (of 15):

1-I 2016 Scorecard

Scorecard - Erie Thames Powerlines Corporation

8/17/2017

Performance Outcomes	Performance Categories	Measures		2012	2013	2014	2015	2016	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		98.80%	98.80%	99.40%	98.40%	99.60%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		94.60%	95.80%	95.50%	98.40%	98.40%		65.00%	
	Customer Satisfaction	First Contact Resolution				99.7%	99.85	99.54			
		Billing Accuracy				99.85%	99.46%	99.50%		98.00%	
		Customer Satisfaction Survey Results				100 %	89%	89			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness					83.40%	83.40%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	NI	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.47	0.41	0.59	0.73	1.46			0.99
		Average Number of Times that Power to a Customer is Interrupted [2]		0.31	0.20	0.30	0.48	0.24			0.41
	Asset Management	Distribution System Plan Implementation Progress				In Progress	94%	104			
	Cost Control	Efficiency Assessment		4	3	3	3	3			
		Total Cost per Customer [3]		$564	$610	$631	$656	$676			
		Total Cost per Km of Line [3]		$30,891	$32,792	$33,707	$34,342	$36,550			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Cumulative Energy Savings [4]					18.75%	31.33%			27.63 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%			100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time			100.00%	92.86%	100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.78	0.75	0.58	0.85	0.88			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.23	1.19	1.05	1.59	1.55			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.12%	9.12%	9.12%	9.12%	9.12%			
			Achieved	8.43%	11.80%	10.63%	9.39%	9.33%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend:
5-year trend: up, down, flat
Current year: target met, target not met

Attachment 10 (of 15):

1-J 2015 Audited Financial Statement

Financial Statements of

ERIE THAMES POWERLINES CORPORATION

Years ended December 31, 2015 and 2014

ERIE THAMES POWERLINES

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

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:

________________ Director

________________ 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 11 (of 15):

I-K 2016 Audited Financial Statement

ERIE THAMES POWERLINES CORPORATION

FINANCIAL STATEMENTS

DECEMBER 31, 2016

Your Home Town Utility

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

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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, 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.

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:

_______________ Director _______________ 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 12 (of 15):

1-L 2014 Mapping to Audited Financial Statement

Erie Thames Powerlines Corporation

2.1.7 Trial Balance Mapping to 2014 Audited Financial Statements

Account No	n	Line Grouping	Account Description	Amount	Line item	Reclass Entries	Ending Line Item	Financial Statement Descriptpion
1606	Assets	Goodwill	Organization	$ 76,666.68	$ 76,666.68		$ 76,666.68	Goodwill
1611	Assets	Property Plant and Equipment	Computer Software	$ 1,277,690.91			$ -	
1805	Assets	Property Plant and Equipment	Land	$ 147,918.25			$ -	
1806	Assets	Property Plant and Equipment	Land Rights	$ -			$ -	
1808	Assets	Property Plant and Equipment	Buildings and Fixtures	$ 224,882.23			$ -	
1820	Assets	Property Plant and Equipment	Distribution Station Equipment - Normally Primary below 50 kV	$ 617,563.71			$ -	
1830	Assets	Property Plant and Equipment	Poles, Towers and Fixtures	$ 7,711,126.43			$ -	
1835	Assets	Property Plant and Equipment	Overhead Conductors and Devices	$ 13,352,040.09			$ -	
1840	Assets	Property Plant and Equipment	Underground Conduit	$ 2,763,114.30			$ -	
1845	Assets	Property Plant and Equipment	Underground Conductors and Devices	$ 6,719,334.31			$ -	
1850	Assets	Property Plant and Equipment	Line Transformers	$ 8,258,463.99			$ -	
1855	Assets	Property Plant and Equipment	Services	$ 4,735,334.57			$ -	
1860	Assets	Property Plant and Equipment	Meters	$ 4,868,339.78			$ -	
1910	Assets	Property Plant and Equipment	Leasehold Improvements	$ 287,785.81			$ -	
1915	Assets	Property Plant and Equipment	Office Furniture and Equipment	$ 91,817.80			$ -	
1920	Assets	Property Plant and Equipment	Computer Equipment - Hardware	$ 238,990.16			$ -	
1925	Assets	Property Plant and Equipment	Computer Software	$ -			$ -	
1930	Assets	Property Plant and Equipment	Transportation Equipment	$ 3,106,750.86			$ -	
1940	Assets	Property Plant and Equipment	Tools, Shop and Garage Equipment	$ 216,042.83			$ -	
1945	Assets	Property Plant and Equipment	Measurement and Testing Equipment	$ 14,462.12			$ -	
1950	Assets	Property Plant and Equipment	Power Operated Equipment	$ 64,090.60			$ -	
1980	Assets	Property Plant and Equipment	System Supervisory Equipment	$ 260,036.95			$ -	
1995	Assets	Property Plant and Equipment	Contributions and Grants - Credit	$ (7,601,380.38)			$ -	
2055	Assets	Property Plant and Equipment	Construction Work in Progress--Electric	$ 1,381,364.21			$ -	
2105	Assets	Property Plant and Equipment	Accumulated Amortization of Electric Utility Plan - PP	$ (18,484,596.31)			$ -	
2120	Assets	Property Plant and Equipment	Accumulated Ammortization of Electric Utility-Intangibles	$ (81,761.33)	$ 30,169,411.89		$ 30,169,411.89	Property, Plant and Equipment
1495	Assets	Future PILS of Income Tax	Future Regulatory Taxes receivable	$ 339,000.00	$ 339,000.00		$ 339,000.00	Future Payment in Lieu of Income Tax Asset
1508	Current Assets	Regulatory Assets	Other Regulatory Assets	$ 56,218.30			$ -	
1521	Current Assets	Regulatory Assets	Special Purpose Charge Assessment Variance	$ -			$ -	
1551	Current Assets	Regulatory Assets	CGAAP Accounting Changes	$ 10,660.61			$ -	
1555	Current Assets	Regulatory Assets	Smart Meter Capital and Recovery Offset Variance	$ -			$ -	
1556	Current Assets	Regulatory Assets	Smart Meter OM&A Variance	$ -			$ -	
1562	Current Assets	Regulatory Assets	Deferred Payments in Lieu of Taxes	$ -			$ -	
1589	Current Assets	Regulatory Assets	RSVA-Global Adjustment	$ 1,886,559.99			$ -	
1590	Current Assets	Regulatory Assets	Recovery of regulatory asset balances	$ -			$ -	
1520	Current Assets	Regulatory Assets	Power Purchase Variance Account	$ -			$ -	
1550	Current Assets	Regulatory Assets	LV Variance Account	$ 514,850.78			$ -	
1565	Current Assets	Regulatory Assets	Conservation and Demand Management Expenditures and Recoveries	$ -			$ -	
1566	Current Assets	Regulatory Assets	CDM Contra	$ -			$ -	
1580	Current Assets	Regulatory Assets	RSVAWMS	$ (326,539.60)			$ -	
1582	Current Assets	Regulatory Assets	RSVAONE-TIME	$ -			$ -	
1584	Current Assets	Regulatory Assets	RSVANW	$ 208,862.50			$ -	
1586	Current Assets	Regulatory Assets	RSVACN	$ 750,851.84			$ -	
1588	Current Assets	Regulatory Assets	RSVAPOWER	$ 1,427,381.93	$ 4,528,846.35	$ (2,911,448.81)	$ 1,617,397.54	Current -Regulatory Assets
	Assets	Regulatory Assets	Non-Current Regulatory Assets	$ -	$ -	$ 3,369,018.31	$ 3,369,018.31	Regulatory Assets
1100	Current Assets	Accounts Receivable	Customer Accounts Receivable	$ 4,393,366.10			$ -	
1102	Current Assets	Accounts Receivable	Accounts Receivable - Services	$ 183,261.10			$ -	
1105	Current Assets	Accounts Receivable	Accounts Receivable - Merchandise, Jobbing, etc.	$ -			$ -	
1110	Current Assets	Accounts Receivable	Other Accounts Receivable	$ 1,164,848.83			$ -	
1120	Current Assets	Accounts Receivable	Accrued Utility Revenues	$ 4,959,234.69			$ -	
1130	Current Assets	Accounts Receivable	Accumulated Provision for Uncollectible Accounts--Credit	$ (684,944.40)	$ 10,015,766.32		$ 10,015,766.32	Accounts Receivable
1210	Current Assets	Accounts Receivable	Notes Receivable from Associated Companies	$ -			$ -	
1200	Current Assets	Accounts Receivable	Accounts Receivable from Associated Companies	$ 238.09	$ 238.09		$ 238.09	Due from Related Parties
1330	Current Assets	Inventory	Plant Materials and Operating Supplies	$ 169,979.08	$ 169,979.08		$ 169,979.08	Inventory
1070	Current Assets	Prepayments	Current Investments	$ 20,804.59	$ 20,804.59		$ 20,804.59	Investment
1180	Current Assets	Prepayments	Prepayments	$ 112,966.84	$ 112,966.84		$ 112,966.84	Prepaid Expenses
2205	Current Liabilities	Accounts Payable	Accounts Payable	$ (9,190,013.77)			$ -	
2250	Current Liabilities	Accounts Payable	Debt Retirement Charges(DRC) Payable	$ (544,057.01)			$ -	
2290	Current Liabilities	Accounts Payable	Commodity Taxes	$ 380,752.26	$ (9,353,318.52)		$ (9,353,318.52)	Accounts Payable and Accrued Liabilities
1005	Current Liabilities	Cash	Cash	$ -			$ -	
1010	Current Liabilities	Cash	Cash	$ -			$ -	
2260	Current Liabilities	Current Portion Long Term Debt	Current Portion Long Term Debt	$ -		$ (115,819.28)	$ (115,819.28)	Current Portion of long-term debt
2210	Current Liabilities	Customer Deposits	AP - MISC AR DEPOSITS	$ (220,725.31)			$ -	
2335	Current Liabilities	Customer deposits	Long Term Customer Deposits	$ (752,556.73)	$ (973,282.04)		$ (973,282.04)	Customer Deposits
2225	Current Liabilities	Demand Operating Loan	Notes and Loans Payable	$ (5,411,328.62)	$ (5,411,328.62)		$ (5,411,328.62)	Demand Operating Loan
2294	Current Liabilities	Payment in Lieu of Income taxes	Accrual for Taxes Payments in Lieu of Taxes, Etc.	$ (165,695.30)	$ (165,695.30)		$ (165,695.30)	Payments in lieu of Income Taxes Payable
2240	Current Liabilities	Due to Related Parties	Accounts Payable to Associated Companies	$ (889,154.47)	$ (889,154.47)		$ (889,154.47)	Due to Related Parties
2242	Current Liabilities	Related Party Notes Payable	Notes Payable to Associated Companies	$ (2,083,391.00)	$ (2,083,391.00)		$ (2,083,391.00)	Related-Parties Notes Payable
2520	Liabilities	Related Party Notes Payable	Other Long Term Debt	$ (8,038,524.24)	$ (8,038,524.24)		$ (8,038,524.24)	Related-Party Long-Term Debt
2350	Liabilities	Future Regulatory Taxes Liability	Future Regulatory Taxes Payable	$ (339,000.00)	$ (339,000.00)		$ (339,000.00)	Future Regulatory Taxes Payable
2325	Liabilities		Obligations under Capital Leases	$ (405,354.69)	$ (405,354.69)	$ 115,819.28	$ (289,535.41)	Long-term Debt
2306	Liabilities	Post Retirement Benefit Obligation	Employee Future Benefits	$ (653,100.00)	$ (653,100.00)		$ (653,100.00)	Post-Retirement Benefit Obligation
1568	Current Liabilities	Regulatory Liabilities	LRAM Variance	$ (67,181.46)			$ -	
1576	Current Liabilities	Regulatory Liabilities	CGAAP Accounting Changes	$ (758,464.92)			$ -	
1595	Current Liabilities	Regulatory Liabilities	Disposition and Recovery of Regulatory Balances Control Account	$ (1,518,211.86)			$ -	
2405	Current Liabilities	Regulatory Liabilities	Other Regulatory Liabilities	$ (45,697.56)	$ (2,389,555.80)	$ 77,076.37	$ (2,312,479.43)	Current Regulatory Liabilities
	Liabilities	Regulatory Liabilities			$ -	$ (534,646.68)	$ (534,646.68)	Regulatory Liabilities
3005	Equity	Share Capital	Common Shares Issued	$ (10,855,584.70)	$ (10,855,584.70)		$ (10,855,584.70)	Share Capital
3040	Equity	Retained Earnings	Appropriated Retained Earnings	$ (24,324.94)			$ -	
3045	Equity	Retained Earnings	Unappropriated Retained Earnings	$ 899,341.12			$ -	
3055	Equity	Retained Earnings	Adjustment to Retained Earnings	$ (3,550,702.85)			$ -	
3046	Equity	Retained Earnings	Balance Transferred from Income	$ (1,200,703.79)	$ (3,876,390.46)		$ (3,876,390.46)	Retained Earnings
5705	Income Statement	Amortization	Amortization Expense - Property, Plant, and Equipment	$ 1,467,478.24	$ 1,467,478.24		$ 1,467,478.24	Amortization
5315	Income Statement	Billing and Collecting	Customer Billing	$ 1,036,486.94			$ -	
5330	Income Statement	Billing and Collecting	Collection Charges	$ 188,435.02			$ -	
5335	Income Statement	Billing and Collecting	Bad Debt Expense	$ 22,618.05	$ 1,247,540.01	$ (152,130.01)	$ 1,095,410.00	Billing and Collecting
5425	Income Statement	Community Relatiions	Miscellaneous Customer Service and Informational Expenses	$ (6,655.95)			$ -	
5405	Income Statement	Community Relatiions	Supervision	$ 22,871.32			$ -	
5515	Income Statement	Community Relatiions	Advertising Expense	$ 6,789.87	$ 23,005.24	$ 11,594.04	$ 34,599.28	Community Relations
4705	Income Statement	Cost of Power	Power Purchased	$ 16,287,716.32			$ -	
4706	Statement	Cost of Power	Global Adjustment	$ 25,251,275.19			$ -	
4708	Income Statement	Cost of Power	s-WMS	$ 2,479,095.96			$ -	
4712	Income Statement	Cost of Power	Charges-One-Time	$ -			$ -	
4714	Income Statement	Cost of Power	Charges-NW	$ 2,978,627.95			$ -	
4716	Income Statement	Cost of Power	Charges-CN	$ 1,915,072.40			$ -	
4750	Income Statement	Cost of Power	Charges - LV	$ 755,712.43			$ -	
4751	Income Statement	Cost of Power	Charges- Smart Meter Entity Charge	$ 172,084.53	$ 49,839,584.78		$ 49,839,584.78	Cost of Power

Erie Thames Powerlines Corporation

2.1.7 Trial Balance Mapping to 2014 Audited Financial Statements

Account No	[illegible]n	Line Grouping	Account Description	Amount	Line item	Reclass Entries	Ending Line Item	Financial Statement Descriptpion
5005	Income Statement	Direct Operation	Operation Supervision and Engineering	$ 40,365.05			$ -	
5025	Income Statement	Direct Operation	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ -			$ -	
5065	Income Statement	Direct Operation	Meter Expense	$ -			$ -	
5085	Income Statement	Direct Operation	Miscellaneous Distribution Expense	$ 67,609.76			$ -	
5096	Income Statement	Direct Operation	Other Rent	$ 2,042.89			$ -	
5110	Income Statement	Direct Operation	Maintenance of Buildings and Fixtures - Distribution Stations	$ 89,209.80			$ -	
5112	Income Statement	Direct Operation	Maintenance of Transformer Station Equipment	$ 26,687.85			$ -	
5114	[illegible] Statement	Direct Operation	Maintenance of Distribution Station Equipment	$ -			$ -	
5120	Income Statement	Direct Operation	Maintenance of Poles, Towers and Fixtures	$ 47,176.03			$ -	
5125	Income Statement	Direct Operation	Maintenance of Overhead Conductors and Devices	$ -			$ -	
5130	Income Statement	Direct Operation	Maintenance of Overhead Services	$ 84,725.73			$ -	
5135	Income Statement	Direct Operation	Overhead Distribution Lines and Feeders - Right of Way	$ 83,105.00			$ -	
5150	Income Statement	Direct Operation	Maintenance of Underground Conductors and Devices	$ 21,893.00			$ -	
5155	Income Statement	Direct Operation	[illegible]nance of Underground Services	$ 148,348.19			$ -	
5160	Income Statement	Direct Operation	Maintenance of Line Transformers	$ 40,277.85			$ -	
5175	Income Statement	Direct Operation	Maintenance of Meters	$ 36,735.96			$ -	
5615	Income Statement	Direct Operation	General Administrative Salaries and Expenses	$ 218,483.86			$ -	
5610	Income Statement	Direct Operation	Management Salaries and Expenses	$ 1,191,169.02			$ -	
5605	Income Statement	Direct Operation	Executive Salaries and Expenses	$ 256,217.94			$ -	
5635	Income Statement	Direct Operation	Property Insurance	$ 28,128.24			$ -	
5645	Income Statement	Direct Operation	Employee Pensions and Benefits	$ 1,013,855.30			$ -	
5675	Income Statement	Direct Operation	Maintenance of General Plant	$ -			$ -	
6105	Income Statement	Direct Operation	Taxes Other Than Income Taxes	$ 48,531.28			$ -	
6225	Income Statement	Direct Operation	Other Deducitons	$ -	$ 3,444,562.75	$ 160,625.25	$ 3,605,188.00	Direct Operation
4006	[illegible] Statement	Electricity Revenue	[illegible]ntial Energy Sales	$ (11,690,740.22)			$ -	
4010	Income Statement	Electricity Revenue	Commercial Energy Sales	$ (2,115,426.41)			$ -	
4015	Income Statement	Electricity Revenue	Industrial Energy Sales	$ (1,140,648.87)			$ -	
4020	Income Statement	Electricity Revenue	Energy Sales to Large Users	$ (3,365,746.80)			$ -	
4025	Income Statement	Electricity Revenue	Street Lighting Energy Sales	$ (101,876.12)			$ -	
4030	Income Statement	Electricity Revenue	Sentinel Lighting Energy Sales	$ (29,164.25)			$ -	
4035	Income Statement	Electricity Revenue	General Energy Sales	$ (22,430,119.02)			$ -	
4050	Income Statement	Electricity Revenue	Revenue Adjustment	$ 1,986,074.55			$ -	
4055	Income Statement	Electricity Revenue	Energy Sales for Resale	$ (2,651,346.38)			$ -	
4062	Income Statement	Electricity Revenue	Billed WMS	$ (2,479,095.96)			$ -	
4066	Income Statement	Electricity Revenue	Billed NW	$ (2,978,627.97)			$ -	
4068	[illegible] Statement	Electricity Revenue	Billed CN	$ (1,915,072.42)			$ -	
4075	Income Statement	Electricity Revenue	Billed - LV	$ (755,712.41)			$ -	
4076	Income Statement	Electricity Revenue	Billed -Smart Meter Entity Charge	$ (172,084.53)			$ -	
4080	Income Statement	Electricity Revenue	Distribution Services Revenue	$ (9,620,817.84)	$ (59,460,404.65)		$ (59,460,404.65)	Electricity Revenue
6005	Income Statement	Interest Expense	Interest on Long Term Debt	$ 1,308,399.76			$ -	
6035	Income Statement	Interest Expense	Other Interest Expense	$ 82,097.54			$ -	
6045	Income Statement	Interest Expense	Interest Expense on capital lease obligations	$ -	$ 1,390,497.30	$ 35,087.93	$ 1,425,585.23	Interest
4405	Income Statement	Interest Income on Reg Assets	Interest and Dividend Income	$ (70,829.01)	$ (70,829.01)	$ 1,027.01	$ (69,802.00)	Interest Income on Regulatory Assets
5670	Income Statement	Office and Administration	Rent	$ 228,677.02			$ -	
5665	Income Statement	Office and Administration	Miscellaneous General Expenses	$ 414,871.15			$ -	
6205	Income Statement	Office and Administration	Donations	$ 11,925.00			$ -	
5620	Income Statement	Office and Administration	Office Supplies and Expenses	$ 94,764.95	$ 750,238.12	$ (35,087.93)	$ 715,150.19	Office and Administration
5630	Income Statement	Regulatory and Professional	Outside Services Employed	$ 126,796.88			$ -	
5655	Income Statement	Regulatory and Professional	Regulatory Expenses	$ 59,336.92	$ 186,133.80	$ 39,664.38	$ 225,798.18	Regulatory and Professional
4082	Income Statement	Service Revenue	Retail Services Revenues	$ (14,815.00)			$ -	
4084	Income Statement	Service Revenue	Service Transaction Requests (STR) Revenues	$ (7,069.95)			$ -	
4210	Income Statement	Service Revenue	Rent from Electric Property	$ (104,876.83)			$ -	
4220	Income Statement	Service Revenue	Other Electric Revenues	$ (6,987.43)			$ -	
4225	Income Statement	Service Revenue	Late Payment Charges	$ (109,434.71)			$ -	
4235	Income Statement	Service Revenue	Miscellaneous Service Revenues	$ (113,765.00)			$ -	
4324	Income Statement	Service Revenue	Special Purpose Charge Recovery	$ -			$ -	
4325	Income Statement	Service Revenue	Revenues from Merchandising Jobbing etc.	$ -			$ -	
4330	Income Statement	Service Revenue	Costs and Expenses of Merchandising, Jobbing, Etc.	$ -			$ -	
4375	Income Statement	Service Revenue	Revenues from Non-Utility Operations	$ (22,329.37)			$ -	
4380	Income Statement	Service Revenue	Expenses of Non-Utility Operations	$ 8,316.94			$ -	
4390	Income Statement	Service Revenue	Miscellaneous Non-Operating Income	$ (18,420.45)	$ (389,381.80)	$ (59,753.56)	$ (449,135.36)	Service Revenue
	Income Statement	Interest Income	Interest Income	$ -		$ (3,210.00)	$ (3,210.00)	Interest Income
4355	Income Statement	Loss on Sale of Equipment	Gain on Disposal	$ 7,659.71	$ 7,659.71	$ 2,183.70	$ 9,843.41	Loss on Sale of Equipment
4305	Income Statement	MIFRS regulatory adjustment	Amortization CGAAP/MCGAAP Varaince-DR	$ 147,211.72	$ 147,211.72		$ 147,211.72	MIFRS Regulatory Adjustment
6110	Income Statement	Payments in Lieu of Income	Income Taxes	$ 216,000.00	$ 216,000.00		$ 216,000.00	Payment in Lieu of Income Taxes-Current
2296	Liabilities	Future Regulatory Taxes	Future Regulatory Taxes Payable	$ -			$ -	
2285	Liabilities	Long Term Debt	Obligations under Capital Leases	$ -			$ -	
2425	Liabilities		Other deferred Credits	$ -			$ -	
				$ (1,200,703.79)	**$ (1,200,703.79)**	**$ (0.00)**	**$ (1,200,703.79)**	**Net Income**

Attachment 13 (of 15):

1-M 2015 Mapping to Audited Financial Statement

Erie Thames Powerlines Corporation

2.1.7 Trial Balance Mapping to 2015 Audited Financial Statements

Account No	Section	Line Grouping	Account Description	Amount	CGAAP Statement	IFRS Adjustment	Ending Line Item	
1606	Assets	Goodwill	Organization	$ 76,666.68	$ 76,666.68	$ 521,184.00	$ 597,850.68	Goodwill/Intangible Assets
1611	Assets	Property Plant and Equipment	Computer Software	$ 1,446,051.71			$ -	
1805	Assets	Property Plant and Equipment	Land	$ 104,039.08			$ -	
1806	Assets	Property Plant and Equipment	Land Rights	$ 43,879.17			$ -	
1808	Assets	Property Plant and Equipment	Buildings and Fixtures	$ 253,269.57			$ -	
1820	Assets	Property Plant and Equipment	Distribution Station Equipment - Normally Primary below 50 kV	$ 566,197.41			$ -	
1830	Assets	Property Plant and Equipment	Poles, Towers and Fixtures	$ 8,389,745.58			$ -	
1835	Assets	Property Plant and Equipment	Overhead Conductors and Devices	$ 14,325,843.98			$ -	
1840	Assets	Property Plant and Equipment	Underground Conduit	$ 2,877,038.35			$ -	
1845	Assets	Property Plant and Equipment	Underground Conductors and Devices	$ 7,017,531.70			$ -	
1850	Assets	Property Plant and Equipment	Line Transformers	$ 8,898,199.29			$ -	
1855	Assets	Property Plant and Equipment	Services	$ 5,340,994.38			$ -	
1860	Assets	Property Plant and Equipment	Meters	$ 5,133,176.19			$ -	
1910	Assets	Property Plant and Equipment	Leasehold Improvements	$ 414,832.86			$ -	
1915	Assets	Property Plant and Equipment	Office Furniture and Equipment	$ 97,709.45			$ -	
1920	Assets	Property Plant and Equipment	Computer Equipment - Hardware	$ 250,362.18			$ -	
1925	Assets	Property Plant and Equipment	Computer Software	$ -			$ -	
1930	Assets	Property Plant and Equipment	Transportation Equipment	$ 3,193,997.04			$ -	
1940	Assets	Property Plant and Equipment	Tools, Shop and Garage Equipment	$ 228,293.68			$ -	
1945	Assets	Property Plant and Equipment	Measurement and Testing Equipment	$ 31,082.12			$ -	
1950	Assets	Property Plant and Equipment	Power Operated Equipment	$ 223,085.57			$ -	
1980	Assets	Property Plant and Equipment	System Supervisory Equipment	$ 324,269.00			$ -	
1995	Assets	Property Plant and Equipment	Contributions and Grants - Credit	$ (8,269,099.18)			$ -	
2055	Assets	Property Plant and Equipment	Construction Work in Progress--Electric	$ 2,003,285.64			$ -	
2105	Assets	Property Plant and Equipment	Accumulated Amortization of Electric Utility Plan - PP	$ (19,745,487.02)			$ -	
2120	Assets	Property Plant and Equipment	Accumulated Ammortization of Electric Utility-Intangibles	$ -	$ 33,148,297.75	$ 931,643.00	$ 34,079,940.75	Property, Plant and Equipment
2296	Assets	Future PILS of Income Tax	Future Regulatory Taxes receivable	$ 339,000.00	$ 339,000.00	$ (302,000.00)	$ 37,000.00	Deferred Tax Assets
1508	Current Assets	Regulatory Assets	Other Regulatory Assets	$ 56,218.30			$ -	
1521	Current Assets	Regulatory Assets	Special Purpose Charge Assessment Variance	$ -			$ -	
1551	Current Assets	Regulatory Assets	CGAAP Accounting Changes	$ -			$ -	
1555	Current Assets	Regulatory Assets	Smart Meter Capital and Recovery Offset Variance	$ -			$ -	
1556	Current Assets	Regulatory Assets	Smart Meter OM&A Variance	$ -			$ -	
1562	Current Assets	Regulatory Assets	Smart Metering Entity Variance	$ (6,491.33)			$ -	
1568	Current Assets	Regulatory Assets	LRAM Variance	$ 86,165.66				
1589	Current Assets	Regulatory Assets	RSVA-Global Adjustment	$ 4,149,086.64			$ -	
1595	Current Assets	Regulatory Assets	Recovery of regulatory asset balances	$ 318,214.85			$ -	
1520	Current Assets	Regulatory Assets	Power Purchase Variance Account	$ -			$ -	
1550	Current Assets	Regulatory Assets	LV Variance Account	$ 836,077.34			$ -	
1565	Current Assets	Regulatory Assets	Conservation and Demand Management Expenditures and Recoveries	$ -			$ -	
1566	Current Assets	Regulatory Assets	CDM Contra	$ -			$ -	
1580	Current Assets	Regulatory Assets	RSVAWMS	$ -			$ -	
1582	Current Assets	Regulatory Assets	RSVAONE-TIME	$ -			$ -	
1584	Current Assets	Regulatory Assets	RSVANW	$ -			$ -	
1586	Current Assets	Regulatory Assets	RSVACN	$ 273,733.38			$ -	
1588	Current Assets	Regulatory Assets	RSVAPOWER	$ -	$ 5,713,004.84	$ (5,713,004.84)	$ -	Current -Regulatory Assets
1100	Current Assets	Accounts Receivable	Customer Accounts Receivable	$ 4,612,003.58			$ -	
1102	Current Assets	Accounts Receivable	Accounts Receivable - Services	$ 330,915.66			$ -	
1105	Current Assets	Accounts Receivable	Accounts Receivable - Merchandise, Jobbing, etc.	$ -			$ -	
1110	Current Assets	Accounts Receivable	Other Accounts Receivable	$ 682,602.17			$ -	
1130	Current Assets	Accounts Receivable	Accumulated Provision for Uncollectible Accounts--Credit	$ (804,806.01)	$ 4,820,715.40	$ 32,201.60	$ 4,852,917.00	Accounts Receivable
1120	Current Assets	Accounts Receivable	Accrued Utility Revenues	$ 5,616,741.50	$ 5,616,741.50		$ 5,616,741.50	Unbilled Revenue
1210	Current Assets	Accounts Receivable	Notes Receivable from Associated Companies	$ -			$ -	
1200	Current Assets	Accounts Receivable	Accounts Receivable from Associated Companies	$ 91,040.68	$ 91,040.68	$ 6,116.00	$ 97,156.68	Due from Related Parties
1330	Current Assets	Inventory	Plant Materials and Operating Supplies	$ 86,524.52	$ 86,524.52		$ 86,524.52	Inventory
1070	Current Assets	Prepayments	Current Investments	$ 21,415.04	$ 21,415.04		$ 21,415.04	Investment
1180	Current Assets	Prepayments	Prepayments	$ 82,069.71	$ 82,069.71		$ 82,069.71	Prepaid Expenses
2294	Current Assets		Payment in lieu of taxes receivable	$ 204,555.00	$ 204,555.00		$ 204,555.00	Payment in lieu of taxes receivable
	Assets	Regulatory Assets	Regulatory Balances	$ -	$ -	$ 6,154,937.00	$ 6,154,937.00	Regulatory Balances (Assets)
2205	Current Liabilities	Accounts Payable	Accounts Payable	$ (9,037,811.84)				
2250	Current Liabilities	Accounts Payable	Debt Retirement Charges(DRC) Payable	$ (250,388.84)				
2290	Current Liabilities	Accounts Payable	Commodity Taxes	$ 359,976.09	$ (8,928,224.59)	$ 554,848.00	$ (8,373,376.59)	Accounts Payable and Accrued Liabilities
2225	Current Liabilities	Notes Payable	Notes and Loans Payable	$ (1,695,391.12)	$ (1,695,391.12)		$ (1,695,391.12)	Bank Overdraft
2310	Current Liabilities	Current Portion Long Term Debt	Current Portion Long Term Debt	$ (108,049.46)	$ (108,049.46)		$ (108,049.46)	Current Portion of long-term debt
2310	Current Liabilities	Current Portion Long Term Debt	Current Portion Long Term Debt	$ 108,049.46	$ 108,049.46	$ (108,049.46)	$ -	Current Portion of long-term debt
2210	Current Liabilities	Customer Deposits	AP - MISC AR DEPOSITS	$ (334,463.97)			$ -	
2335	Current Liabilities	Customer deposits	Long Term Customer Deposits	$ (760,379.28)	$ (1,094,843.25)	$ 334,464.00	$ (760,379.25)	Customer Deposits
2225	Current Liabilities	Demand Operating Loan	Notes and Loans Payable	$ -	$ -	$ -	$ -	
2294	Current Liabilities	Payment in Lieu of Income taxes	Accrual for Taxes Payments in Lieu of Taxes, Etc.	$ -	$ -		$ -	Payments in lieu of Income Taxes Payable
2240	Current Liabilities	Due to Related Parties	Accounts Payable to Associated Companies	$ (309,957.51)			$ -	
2525	Current Liabilities	Due to Related Parties	Term Bank Loans - Long Term Portion	$ (10,000,000.00)				
3049	Current Liabilities	Due to Related Parties	Dividends Payable-Common Shares	$ 2,000,000.00	$ (8,309,957.51)	$ 7,406,836.51	$ (903,121.00)	Due to Related Parties
2242	Current Liabilities	Related Party Notes Payable	Notes Payable to Associated Companies	$ (2,083,391.00)	$ (2,083,391.00)	$ 2,083,391.00	$ -	Related Parties Notes Payable
	Current Liabilities	Deferred Revenue	Deferred Revenue	$ -	$ -	$ (472,282.00)	$ (472,282.00)	Deferred Revenue -Current
2520	Liabilities	Related Party Notes Payable	Other Long Term Debt	$ (8,038,524.24)	$ (8,038,524.24)	$ 8,038,524.24	$ -	Related-Party Long-Term Debt
2350	Liabilities	Future Regulatory Taxes Liability	Future Regulatory Taxes Payable	$ (339,000.00)	$ (339,000.00)	$ 339,000.00	$ -	Deferred Tax Liability
2325	Liabilities	Long Term Debt	Obligations under Capital Leases	$ (289,758.79)	$ (289,758.79)	$ (20,013,866.21)	$ (20,303,625.00)	Long-term Debt
2306	Liabilities	Post Retirement Benefit Obligation	Employee Future Benefits	$ (653,100.00)	$ (653,100.00)	$ (176,000.00)	$ (829,100.00)	Post-Retirement Benefit Obligation
	Liabilities	Deferred Revenue	Deferred Revenue	$ -	$ -	$ (1,315,009.00)	$ (1,315,009.00)	Deferred Revenue
1576	Liabilities	Regulatory Liabilities	CGAAP Accounting Changes	$ (962,818.89)			$ -	
1580	Liabilities	Regulatory Liabilities	RSVAWMS	$ (952,496.20)			$ -	
1584	Liabilities	Regulatory Liabilities	RSVANW	$ (57,473.77)				
1588	Liabilities	Regulatory Liabilities	RSVAPOWER	$ (1,060,669.23)				
2425	Liabilities	Regulatory Liabilities	Other Deferred Credits	$ (13,295.63)	$ (3,046,753.72)	$ 3,046,753.72	$ -	Regulatory Liabilities
3005	Equity	Share Capital	Common Shares Issued	$ (10,855,584.70)	$ (10,855,584.70)		$ (10,855,584.70)	Share Capital
3040	Equity	Retained Earnings	Appropriated Retained Earnings	$ (24,324.94)			$ -	
3045	Equity	Retained Earnings	Unappropriated Retained Earnings	$ 899,341.12			$ -	
3055	Equity	Retained Earnings	Adjustment to Retained Earnings	$ (4,751,406.64)			$ -	
3046	Equity	Retained Earnings	Balance Transferred from Income	$ (989,111.74)	$ (4,865,502.20)	$ 2,065,192.20	$ (2,800,310.00)	Retained Earnings
	Equity		Accumulated other Comprehensive Income			$ 110,806.00	$ 110,806.00	Accumulated other Comprehensive Income
			Regulatory Balances			$ (3,525,686.00)	$ (3,525,686.00)	Regulatory Balances (Liabilities)
4006	Statement	Electricity Revenue	ntial Energy Sales	$ (12,668,436.23)			$ -	
4010	Income Statement	Electricity Revenue	Commercial Energy Sales	$ (4,018,264.56)			$ -	
4015	Income Statement	Electricity Revenue	Industrial Energy Sales	$ (1,458,238.78)			$ -	
4020	Income Statement	Electricity Revenue	Energy Sales to Large Users	$ (2,369,698.04)			$ -	
4025	Income Statement	Electricity Revenue	Street Lighting Energy Sales	$ (84,254.23)			$ -	
4030	Income Statement	Electricity Revenue	Sentinel Lighting Energy Sales	$ (24,378.61)			$ -	
4035	Income Statement	Electricity Revenue	General Energy Sales	$ (23,795,590.60)			$ -	
4050	Income Statement	Electricity Revenue	Revenue Adjustment	$ -			$ -	
4055	Income Statement	Electricity Revenue	Energy Sales for Resale	$ (1,653,520.10)			$ -	
4062	Income Statement	Electricity Revenue	Billed WMS	$ (1,941,677.17)			$ -	
4066	Income Statement	Electricity Revenue	Billed NW	$ (3,001,602.61)			$ -	
4068	Statement	Electricity Revenue	Billed CN	$ (2,083,406.88)			$ -	
4075	Income Statement	Electricity Revenue	Billed - LV	$ (718,985.99)	$ (53,987,814.17)	$ 314,097.68	$ (53,673,716.49)	Electricity Revenue
4076	Income Statement	Electricity Revenue	Billed -Smart Meter Entity Charge	$ (169,760.37)			$ -	
4080	Income Statement	Service Revenue	Distribution Services Revenue	$ (9,726,379.15)			$ -	
4086	Income Statement	Service Revenue	SSS Administration Revenue	$ (64,288.31)	$ (9,790,667.46)		$ (9,790,667.46)	Distribution Revenue
4082	Income Statement	Service Revenue	Retail Services Revenues	$ (18,983.00)			$ -	
4084	Income Statement	Service Revenue	Service Transaction Requests (STR) Revenues	$ (8,670.25)			$ -	
4210	Income Statement	Service Revenue	Rent from Electric Property	$ (95,333.82)			$ -	
4220	Income Statement	Service Revenue	Other Electric Revenues	$ (79,612.65)				
4225	Income Statement	Service Revenue	Late Payment Charges	$ (112,833.85)				
4235	Income Statement	Service Revenue	Miscellaneous Service Revenues	$ (103,720.00)			$ -	
4375	Income Statement	Service Revenue	Revenues from Non-Utility Operations	$ (203,359.63)			$ -	
4390	Income Statement	Service Revenue	Miscellaneous Non-Operating Income	$ (12,004.23)	$ (634,517.43)	$ 634,517.43	$ -	Service Revenue
4340	Income Statement	Interest Income	Profits and Losses from Financial Instrument Investments	$ (610.45)	$ (610.45)	$ 610.45	$ -	Interest Income
4305	Income Statement	MIFRS regulatory adjustment	Amortization CGAAP/MCGAAP Varaince-DR	$ 224,505.01	$ 224,505.01	$ (224,505.01)	$ -	
4355	Income Statement	Loss on Sale of Equipment	Gain on Disposition of Utility and Other Property	$ 20,829.01	$ 20,829.01	$ (20,829.01)	$ -	
	Income Statement	Other	Other	$ -		$ (473,117.00)	$ (473,117.00)	Other

Erie Thames Powerlines Corporation

2.1.7 Trial Balance Mapping to 2015 Audited Financial Statements

Account No	Section	Line Grouping	Account Description	Amount	CGAAP Statement	IFRS Adjustment	Ending Line Item	
4705	Income Statement	Cost of Power	Power Purchased	$ 10,924,773.01			$ -	
4706	Statement	Cost of Power	Global Adjustment	$ 35,147,608.14			$ -	
4708	Income Statement	Cost of Power	es-WMS	$ 1,941,677.17			$ -	
4712	Income Statement	Cost of Power	Charges-One-Time				$ -	
4714	Income Statement	Cost of Power	Charges-NW	$ 3,001,602.60			$ -	
4716	Income Statement	Cost of Power	Charges-CN	$ 2,083,406.86			$ -	
4750	Income Statement	Cost of Power	Charges - LV	$ 718,985.99			$ -	
4751	Income Statement	Cost of Power	Charges- Smart Meter Entity Charge	$ 169,760.37	$ 53,987,814.14	$ 438,200.99	$ 54,426,015.13	Cost of Power
4380	Income Statement	Direct Operation	Expenses of Non-Utility Operations	$ 459,532.16			$ -	
5005	Income Statement	Direct Operation	Operation Supervision and Engineering	$ 42,370.14			$ -	
5025	Income Statement	Direct Operation	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses				$ -	
5065	Income Statement	Direct Operation	Meter Expense				$ -	
5085	Income Statement	Direct Operation	Miscellaneous Distribution Expense	$ 85,389.08			$ -	
5096	Income Statement	Direct Operation	Other Rent	$ 810.00			$ -	
5110	Income Statement	Direct Operation	Maintenance of Buildings and Fixtures - Distribution Stations	$ 62,772.34			$ -	
5112	Income Statement	Direct Operation	Maintenance of Transformer Station Equipment	$ 53,287.28			$ -	
5114	Statement	Direct Operation	Maintenance of Distribution Station Equipment				$ -	
5120	Income Statement	Direct Operation	Maintenance of Poles, Towers and Fixtures	$ 56,496.70			$ -	
5125	Income Statement	Direct Operation	Maintenance of Overhead Conductors and Devices				$ -	
5130	Income Statement	Direct Operation	Maintenance of Overhead Services	$ 165,309.92			$ -	
5135	Income Statement	Direct Operation	Overhead Distribution Lines and Feeders - Right of Way	$ 136,952.24			$ -	
5150	Income Statement	Direct Operation	Maintenance of Underground Conductors and Devices	$ 9,237.23			$ -	
5155	Income Statement	Direct Operation	nance of Underground Services	$ (339,010.07)			$ -	
5160	Income Statement	Direct Operation	Maintenance of Line Transformers	$ 41,450.48			$ -	
5175	Income Statement	Direct Operation	Maintenance of Meters	$ 133,663.83			$ -	
5605	Income Statement	Direct Operation	Executive Salaries and Expenses	$ 255,459.68			$ -	
5610	Income Statement	Direct Operation	Management Salaries and Expenses	$ 1,248,014.54			$ -	
5615	Income Statement	Direct Operation	General Administrative Salaries and Expenses	$ 112,292.16			$ -	
5635	Income Statement	Direct Operation	Property Insurance	$ 25,072.39			$ -	
5645	Income Statement	Direct Operation	Employee Pensions and Benefits	$ 1,027,162.91			$ -	
5675	Income Statement	Direct Operation	Maintenance of General Plant	$ 330,340.54			$ -	
6105	Income Statement	Direct Operation	Taxes Other Than Income Taxes	$ 64,612.40	$ 3,971,215.95	$ (3,971,215.95)	$ -	Direct Operation
5315	Income Statement	Billing and Collecting	Customer Billing	$ 840,661.94			$ -	
5330	Income Statement	Billing and Collecting	Collection Charges	$ 183,012.24				
5335	Income Statement	Billing and Collecting	Bad Debt Expense	$ 87,793.37	$ 1,111,467.55	$ (1,111,467.55)	$ -	Billing and Collecting
5405	Income Statement	Community Relatiions	Supervision				$ -	
5410	Income Statement	Community Relatiions	Miscellaneous Customer Service and Informational Expenses	$ 21,168.29				
5425	Income Statement	Community Relatiions	Miscellaneous Customer Service and Informational Expenses	$ 3,681.32			$ -	
5515	Income Statement	Community Relatiions	Advertising Expense	$ 7,043.80	$ 31,893.41	$ (31,893.41)	$ -	Community Relations
5620	Income Statement	Office and Administration	Office Supplies and Expenses	$ 86,341.94			$ -	
5665	Income Statement	Office and Administration	Miscellaneous General Expenses	$ 605,348.74			$ -	
5670	Income Statement	Office and Administration	Rent	$ 227,975.36			$ -	
6205	Income Statement	Office and Administration	Donations (LEAP)	$ 11,825.00	$ 931,491.04	-931491.04	$ -	Office and Administration
5630	Income Statement	Regulatory and Professional	Outside Services Employed	$ 191,698.53			$ -	
5655	Income Statement	Regulatory and Professional	Regulatory Expenses	$ 78,600.87	$ 270,299.40	$ (270,299.40)	$ -	Regulatory and Professional
	Income Statement	Employee Salaries & Benefits	Employee Salaries & Benefits	$ -		$ 3,205,747.00	$ 3,205,747.00	
	Income Statement	Operating Expenses	Operating Expenses	$ -		$ 2,985,667.00	$ 2,985,667.00	
5705	Income Statement	Amortization	Amortization Expense - Property, Plant, and Equipment	$ 1,525,419.47	$ 1,525,419.47	$ 19,080.00	$ 1,544,499.47	Amortization
6035	Income Statement	Interest Expense	Other Interest Expense	$ 70,543.22			$ -	
6005	Income Statement	Interest Expense	Interest on Long Term Debt	$ 1,308,680.76	$ 1,379,223.98	$ (58,496.50)	$ 1,320,727.48	Finance Costs
4405	Income Statement	Interest Income on Reg Assets	Interest and Dividend Income	$ (57,661.20)	$ (57,661.20)	$ 57,661.20	$ -	Finance Income
6110	Income Statement	Payments in Lieu of Income	Income Taxes	$ 28,000.00	$ 28,000.00	$ 236,000.00	$ 264,000.00	Income Tax
							$ -	
	Income Statement	Net Income	Net Income	-989111.75	-989111.75	798266.88	$ (190,844.87)	Net Income
	Income Statement	Regulatory Balances	Net movement in regulatory balances net of tax	0	$ -	$ (762,959.00)	$ (762,959.00)	Net Movement in Regulatory Balances
	Income Statement	Other comprehensive Income	FV instruments		$ -	$ (610.00)	$ (610.00)	
	Income Statement	Other comprehensive Income	Remeasurement of post-employment benefits		$ -	$ (500.00)	$ (500.00)	
			Total comprehensive income for the year		-$ 989,111.75	$ 34,197.88	$ (954,913.87)	

Attachment 14 (of 15):

1-N 2016 Mapping to Audited Financial Statement

Erie Thames Powerlines Corporation

2.1.7 Trial Balance Mapping to 2016 Audited Financial Statements

Account No	Section	Line Grouping	Account Description	Amount	Total Before Reclass	Reclass	Total	Financial Statement Description
CURRENT ASSETS								
1100	Assets	Current Assets	Customer Accounts Receivable	5,951,531.95				
1102	Assets	Current Assets	Accounts Receivable - Services	705,427.01				
1110	Assets	Current Assets	Other Accounts Receivable	26,407.27				
1130	Assets	Current Assets	Accumulated Provision for Uncollectible Accounts--Credit	- 837,820.05	$5,845,546		$5,845,546	Accounts Receivable
1200	Assets	Current Assets	Accounts Receivable from Associated Companies	141,813.01	$141,813		$141,813	Due from Related Parties
1330	Assets	Inventory	Plant Materials and Operating Supplies	88,157.86	$88,158		$88,158	Materials and Supplies
1120	Assets	Current Assets	Accrued Utility Revenues	6,817,837.21	$6,817,837		$6,817,837	Unbilled Revenue
1180	Assets	Current Assets	Prepayments	92,440.70	$92,441		$92,441	Prepaid Expenses
1495	Assets	Non-Current Assets	Deferred Taxes -Non-Current Assests	16,646.04	$16,646		$16,646	Payment in Lieu of Income Taxes Receivable
					$13,002,441		**$13,002,441**	**Current Assets**
NON-CURRENT ASSETS								
1655	Assets	Generation Plants	Water Wheels, Turbines and Generators	163,929.26				
1805	Assets	Distribution Plant	Land	178,544.08				
1808	Assets	Distribution Plant	Buildings and Fixtures	181,389.01				
1810	Assets	Distribution Plant	Leasehold Improvements	-				
1815	Assets	Distribution Plant	Transformer Station Equipment - Normally Primary above 50 kV	-				
1820	Assets	Distribution Plant	Distribution Station Equipment - Normally Primary below 50 kV	367,963.00				
1825	Assets	Distribution Plant	Storage Battery Equipment	-				
1830	Assets	Distribution Plant	Poles, Towers and Fixtures	6,316,020.32				
1835	Assets	Distribution Plant	Overhead Conductors and Devices	14,713,971.18				
1840	Assets	Distribution Plant	Underground Conduit	1,872,159.20				
1845	Assets	Distribution Plant	Underground Conductors and Devices	4,484,016.83				
1850	Assets	Distribution Plant	Line Transformers	5,587,518.69				
1855	Assets	Distribution Plant	Services	3,585,079.84				
1860	Assets	Distribution Plant	Meters	3,250,686.30				
1865	Assets	Distribution Plant	Other Installations on Customer's Premises	-				
1870	Assets	Distribution Plant	Leased Property on Customer Premises	-				
1875	Assets	Distribution Plant	Street Lighting and Signal Systems	-				
1905	Assets	General Plant	Land	-				
1906	Assets	General Plant	Land Rights	-				
1908	Assets	General Plant	Buildings and Fixtures	-				
1910	Assets	General Plant	Leasehold Improvements	439,555.26				
1915	Assets	General Plant	Office Furniture and Equipment	29,418.00				
1920	Assets	General Plant	Computer Equipment - Hardware	151,089.27				
1930	Assets	General Plant	Transportation Equipment	1,093,031.48				
1935	Assets	General Plant	Stores Equipment	-				
1940	Assets	General Plant	Tools, Shop and Garage Equipment	208,523.47				
1945	Assets	General Plant	Measurement and Testing Equipment	31,082.12				
1950	Assets	General Plant	Power Operated Equipment	224,659.37				
1955	Assets	General Plant	Communication Equipment	31,915.40				
1980	Assets	General Plant	System Supervisory Equipment	512,299.44				
1985	Assets	General Plant	Sentinel Lighting Rental Units	-				
1990	Assets	General Plant	Other Tangible Property	-				
1995	Assets	General Plant	Contributions and Grants - Credit	- 5,826,181.64				
2055	Assets	Other Capital Assets	Construction Work in Progress--Electric	1,789,886.04				
2105	Assets	Accumulated Ammortization	Accumulated Amortization of Electric Utility Plan - PP&E	- 2,552,317.13	$36,834,239		$36,834,239	Property, Plant and Equipment
1606	Assets	Intangible Plant	Organization	76,666.68				
1611	Assets	Intangible Plant	Computer Software	735,511.05				
1612	Assets	Intangible Plant	Land Rights	45,679.17				
2120	Assets	Accumulated Ammortization	Accumulated Amortization of Electric Utility Plant - Intangibles	- 370,260.53	$487,596		$487,596	Intangible Assets
1405	Assets	Non-Current Assets	Non-Current Investments in Non-Associated Companies	25,583.84	$25,584		$25,584	Investments
					$37,347,419		**$37,347,419**	**Non-Current Assets**
REGULATORY BALANCES								
1508	Assets	Other Assets and Deferred Charges	Other Regulatory Assets	29,559.25				
1550	Assets	Other Assets and Deferred Charges	LV Variance Account	1,354,729.00				
1551	Assets	Other Assets and Deferred Charges	Smart Metering Entity Charge Variance Account	- 11,389.22				
1568	Assets	Other Assets and Deferred Charges	LRAM Variance Account	335,000.00				
1575	Assets	Other Assets and Deferred Charges	IFRS-CGAAP Transitional PP&E Amounts	300,612.50				
1576	Assets	Other Assets and Deferred Charges	CGAAP Accounting Changes	- 975,652.49				
1580	Assets	Other Assets and Deferred Charges	RSVA - Wholesale Market Service Charge	- 1,389,821.29				
1582	Assets	Other Assets and Deferred Charges	RSVAONE-TIME	-				
1584	Assets	Other Assets and Deferred Charges	RSVA - Retail Transmission Network Charge	55,516.00				
1586	Assets	Other Assets and Deferred Charges	RSVA - Retail Transmission Connection Charge	239,759.26				
1588	Assets	Other Assets and Deferred Charges	RSVA - Power (excluding Global Adjustment)	- 1,822,912.22				
1589	Assets	Other Assets and Deferred Charges	RSVA - Global Adjustment	3,153,845.39				
1592	Assets	Other Assets and Deferred Charges	2006 PILs & Taxes Variance	-				
1595	Assets	Other Assets and Deferred Charges	Disposition and Recovery/Refund of Regulatory Balances Control Account	1,800,578.35	**$3,069,825**	**$4,864,158**	**$7,933,983**	**Regulatory Balances**
TOTAL ASSETS AND REGULATORY BALANCES					**$53,419,685**	**$4,864,158**	**$58,283,843**	**TOTAL ASSETS AND REGULATORY BALANCES**
CURRENT LIABILITIES								
2225	Liabilities	Current Liabilities	Notes and Loans Payable	- 2,507,866.29	-$2,507,866		-$2,507,866	Bank Indebtedness
2205	Liabilities	Current Liabilities	Accounts Payable	- 11,218,800.26				
2250	Liabilities	Current Liabilities	Debt Retirement Charges(DRC) Payable	- 166,510.71				
2290	Liabilities	Current Liabilities	Commodity Taxes	436,261.40	-$10,949,050		-$10,949,050	Accounts Payable and Acrued Liabilities
2240	Liabilities	Current Liabilities	Accounts Payable to Associated Companies	- 351,075.95	-$351,076		-$351,076	Due to Related Parties
2260	Liabilities	Current Liabilities	Current Long Term Debt	- 192,612.39	-$192,612		-$192,612	Long-Term Debt due with one year'
2210	Liabilities	Current Liabilities	Current Portion of Customer Deposits	- 345,866.00	-$345,866		-$345,866	Customer Deposits
2220	Liabilities	Current Liabilities	Miscellaneous Current and Accrued Liabilities	- 442,724.00	-$442,724		-$442,724	Defered Revenue
						-$231,000	-$231,000	Deferred Tax Liability
					-$14,789,194	**-$231,000**	**-$15,020,194**	**Total Current Liabilities**
NON-CURRENT LIABILITIES								
2325	Liabilities	Non-Current Liabilities	Obligations Under Finance Lease--Non-Current	- 811,487.87				
2520	Liabilities	Long Term Debt	Other Long Term Debt	- 19,929,302.86	-$20,740,791		-$20,740,791	Long-Term Debet
2312	Liabilities	Non-Current Liabilities	Past Service Costs-Other Post-Employment Benefits	- 797,100.00	-$797,100		-$797,100	Post-Employment Benefits
2335	Liabilities	Non-Current Liabilities	Non-Current Customer Deposits	- 606,214.99	-$606,215		-$606,215	Customer Deposits
2440	Liabilities	Other Liabilities and Deferred Credits	Deferred Revenues	- 1,903,059.82	-$1,903,060		-$1,903,060	Deferred Revenue
					-$24,047,166	**$0**	**-$24,047,166**	Total Non-Current Liabilities
EQUITY								
3005	Liabilities	Shareholders Equity	Common Shares Issued	- 10,855,584.70	-$10,855,585		-$10,855,585	Share Capital
3040	es	Shareholders Equity	riated Retained Earnings	- 24,324.94				
3045	Liabilities	Shareholders Equity	Unappropriated Retained Earnings	899,341.12				
3055	es	Shareholders Equity	Adjustment to Retained Earnings	- 3,675,324.39				
3046	Equity	Retained Earnings	Balance Transferred from Income	- 1,009,533.48	-$3,809,841.69	$0.00	-$3,809,841.69	Retained Earnings
3090	Liabilities	Shareholders Equity	Accumulated Other Comprehensive Income	38,837.20	$38,837.20	$0.00	$38,837.20	Accumulated Other Comprehensive Loss
					-$14,626,589.19	**$0.00**	**-$14,626,589.19**	**TOTAL EQUITY**
2405	Liabilities	Other Liabilities and Deferred Credits	Other Regulatory Liabilities or Credits	43,264.40	**$43,264**	**-$4,633,158**	**-$4,589,894**	**Regulatory Balances**
					-$53,419,685	**-$4,864,158**	**-$58,283,843**	**Total Liabilites and Regulatory Balances**
INCOME STATEMENT								
REVENUES								
4006	Income Statement	Sales of Electricity	Residential Energy Sales	- 14,701,935.96				
4010	Income Statement	Sales of Electricity	Commercial Energy Sales	- 4,575,861.90				
4015	Income Statement	Sales of Electricity	Industrial Energy Sales	- 693,537.01				
4020	Income Statement	Sales of Electricity	Energy Sales to Large Users	- 1,719,193.24				
4025	Income Statement	Sales of Electricity	Street Lighting Energy Sales	- 89,239.68				
4030	Income Statement	Sales of Electricity	Sentinel Lighting Energy Sales	- 21,958.97				
4035	Statement	Sales of Electricity	General Energy Sales	- 29,600,892.31				
4050	Income Statement	Sales of Electricity	Revenue Adjustment	1,141,204.20				
4055	Income Statement	Sales of Electricity	Energy Sales for Resale	- 1,226,587.48				
4062	Income Statement	Sales of Electricity	Billed WMS	- 2,223,492.33				
4066	Income Statement	Sales of Electricity	Billed NW	- 3,110,306.65				

Erie Thames Powerlines Corporation

2.1.7 Trial Balance Mapping to 2016 Audited Financial Statements

Account No	Section	Line Grouping	Account Description	Amount	Total Before Reclass	Reclass	Total	Financial Statement Description
4068	Income Statement	Sales of Electricity	Billed CN	- 2,297,362.10				
4075	Income Statement	Sales of Electricity	Billed - LV	- 743,745.20				
4076	Income Statement	Sales of Electricity	Billed – Smart Metering Entity Charge	- 171,411.25	-$60,034,320	-$578,300	-$60,612,620	Sale of Energy
4080	Income Statement	Revenue from Services-Distribution	Distribution Services Revenue	- 10,032,880.05				
4086	Income Statement	Revenue from Services-Distribution	SSS Administration Revenue	- 66,018.63	-$10,098,899		-$10,098,899	Distribution Revenue
4082	Income Statement	Revenue from Services-Distribution	Retail Services Revenues	- 14,779.00				
4084	Income Statement	Revenue from Services-Distribution	Service Transaction Requests (STR) Revenues	- 6,461.05				
4210	Income Statement	Other Operating Income	Rent from Electric Property	- 103,987.32				
4220	Income Statement	Other Operating Income	Other Electric Revenues	4,862.55				
4225	Income Statement	Other Operating Income	Late Payment Charges	- 134,656.29				
4235	Income Statement	Other Operating Income	Miscellaneous Service Revenues	- 105,040.00				
4324	Statement	Other Income/Deductions	Special Purpose Charge Recovery	0.94				
4375	Statement	Other Income/Deductions	Revenues from Non-Utility Operations	- 45,230.95				
4390	Income Statement	Other Income/Deductions	Miscellaneous Non-Operating Income	- 27,347.36				
5740	Income Statement	Amortization Expenses	Amortization of Deferred Charges	- 28,634.98	-$461,273	-$72,223	-$533,496	Other
					-$70,594,492	**-$650,523**	**-$71,245,015**	**TOTAL REVENUES**
OPERATING EXPENSES								
4705	Income Statement	Other Power Supply Expenses	Power Purchased	7,584,438.64				
4707	Income Statement	Other Power Supply Expenses	Charges - Global Adjustment	43,903,561.74				
4708	Income Statement	Other Power Supply Expenses	Charges-WMS	2,223,492.33				
4710	Income Statement	Other Power Supply Expenses	Cost of Power Adjustments	-				
4712	Income Statement	Other Power Supply Expenses	Charges-One-Time	-				
4714	Income Statement	Other Power Supply Expenses	Charges-NW	3,110,306.62				
4715	Income Statement	Other Power Supply Expenses	System Control and Load Dispatching	-				
4716	Income Statement	Other Power Supply Expenses	Charges-CN	2,297,362.11				
4720	Income Statement	Other Power Supply Expenses	Other Expenses	-				
4750	Income Statement	Other Power Supply Expenses	Charges - LV	743,745.20				
4751	Income Statement	Other Power Supply Expenses	Charges – Smart Metering Entity Charge	171,411.25	$60,034,318	$972,006	$61,006,324	Cost of Power Purchased
	Income Statement		Employee Salary and Expenses			$3,182,316	$3,182,316	Employee Salaries and Benefits
5085	Income Statement	Distribution Expenses-Operations	Miscellaneous Distribution Expense	90,763.77				
5096	Income Statement	Distribution Expenses-Operations	Other Rent	810.00				
5110	Income Statement	Distribution Expenses-Maintenance	Maintenance of Buildings and Fixtures - Distribution Stations	22,883.60				
5112	Income Statement	Distribution Expenses-Maintenance	Maintenance of Transformer Station Equipment	-				
5114	Income Statement	Distribution Expenses-Maintenance	Maintenance of Distribution Station Equipment	10,735.22				
5120	Income Statement	Distribution Expenses-Maintenance	Maintenance of Poles, Towers and Fixtures	16,572.69				
5125	Income Statement	Distribution Expenses-Maintenance	Maintenance of Overhead Conductors and Devices	-				
5130	Income Statement	Distribution Expenses-Maintenance	Maintenance of Overhead Services	33,201.84				
5135	Income Statement	Distribution Expenses-Maintenance	Overhead Distribution Lines and Feeders - Right of Way	71,793.78				
5145	Income Statement	Distribution Expenses-Maintenance	Maintenance of Underground Conduit	-				
5150	Income Statement	Distribution Expenses-Maintenance	Maintenance of Underground Conductors and Devices	7,066.34				
5155	Income Statement	Distribution Expenses-Maintenance	Maintenance of Underground Services	64,649.08				
5160	Income Statement	Distribution Expenses-Maintenance	Maintenance of Line Transformers	12,367.97				
5175	Income Statement	Distribution Expenses-Maintenance	Maintenance of Meters	47,531.29				
4355	Income Statement	Other Income/Deductions	Gain on Disposition of Utility and Other Property	- 61,533.56				
5315	Income Statement	Billing and Collecting	Customer Billing	799,615.21				
5320	Income Statement	Billing and Collecting	Collecting	155,827.64				
5335	Income Statement	Billing and Collecting	Bad Debt Expense	26,204.23				
5410	Income Statement	Community Relatiions	Community Relations - Sundry	24,584.33				
5425	Income Statement	Community Relatiions	Miscellaneous Customer Service and Informational Expenses	14,840.32				
5515	Income Statement	Sales Expenses	Advertising Expense	5,969.01				
5520	Income Statement	Sales Expenses	Miscellaneous Sales Expense	-				
5605	Income Statement	Administration and General Expenses	Executive Salaries and Expenses	322,273.80				
5610	Income Statement	Administration and General Expenses	Management Salaries and Expenses	1,265,951.13				
5615	Income Statement	Administration and General Expenses	General Administrative Salaries and Expenses	141,562.65				
5620	Income Statement	Administration and General Expenses	Office Supplies and Expenses	139,937.45				
6205	Income Statement	Donations	Donations	11,925.00				
4380	Income Statement	Other Income/Deductions	Expenses of Non-Utility Operations	267,250.00				
5630	Income Statement	Administration and General Expenses	Outside Services Employed	315,346.30				
5635	Income Statement	Administration and General Expenses	Property Insurance	28,197.49				
5645	Income Statement	Administration and General Expenses	Employee Pensions and Benefits	1,128,552.48				
5655	Income Statement	Administration and General Expenses	Regulatory Expenses	71,081.26				
5665	Income Statement	Administration and General Expenses	Miscellaneous General Expenses	692,968.33				
5670	Income Statement	Administration and General Expenses	Rent	238,525.16				
5675	Income Statement	Administration and General Expenses	Maintenance of General Plant	298,563.39				
6105	Income Statement	Taxes	Taxes Other Than Income Taxes	54,539.62	6,320,556.82	-$3,162,508	3,158,049.00	Operating Expense
5705	Income Statement	Amortization Expenses	Depreciation Expense - Property Plant, and Equipment	1,741,257.37	$1,741,257		$1,741,257	Depreciation and Ammortization
					$68,096,132	**$991,814**	**$69,087,946**	**Total Operating Expenses**
4405	Income Statement	Investment Income	t and Dividend Income	- 66,707.12				
6005	Income Statement	Interest Expense	Interest on Long Term Debt	1,491,276.26				
6035	Income Statement	Interest Expense	Other Interest Expense	62,345.53	**1,486,914.67**	**$72,459**	**$1,559,374**	**Finance Costs**
6110	Income Statement	Taxes	Income Taxes	35,000.00	**$35,000**	**$248,998**	**$283,998**	**Income Tax Expense**
4305	Statement	Other Income/Deductions	tory Debits	- 33,088.18	**$ (33,088)**	**$ (662,749)**	**$ (695,837)**	**Net Movement in Regulatory balances, net of tax**
			Total Profit and Loss		**-$1,009,533**	**-$0**	**-$1,009,534**	
Other Comprehensive Income								
7005	Income Statement	Other Comprehensive Income	Available-for-Sale Financial Asset or Cash Flow Hedge	- 4,168.80				
7010	Income Statement	Other Comprehensive Income	Pension Actuarial Gains or Losses or Remeasurement Adjustment	- 67,800.00	**- 71,968.80**	**$0**	**- 71,968.80**	**Other Comprehensive Income**
					-$1,081,502	**-$0**	**-$1,081,503**	**Total Comprehensive Income for the Year**

Attachment 15 (of 15):

1-O Bill Impact Model

Ontario Energy Board

Tariff Schedule and Bill Impacts Model (2018 Cost of Service Filers)

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **The OEB has established that, when assessing the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, a utility shall evaluate the total bill impact for a low volume residential customer consuming at the distributor's 10th consumption percentile19, to a minimum of 50 kWh per month. Refer to page 62 of Chapter 2 Filing Requirements For Electricity Distribution Rate Applications issued July 14, 2016.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2016 of $0.113/kWh (IESO's Monthly Market Report for May 2016, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact chart for the specific class.
2. Due to the change to energy consumption used in the calculation of GA rate riders for the 2017 rate year, the separate "GA Rate Riders" line is only applicable to the "Proposed" section of the bill impact tables.
3. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0451	1.0338	750		N/A	
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	RPP	1.0451	1.0338	2,000		N/A	
GENERAL SERVICE 50 TO 999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0451	1.0338	65,700	100	DEMAND	
GENERAL SERVICE 1,000 TO 4,999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0451	1.0338	821,250	1,250	DEMAND	
LARGE USE SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0451	1.0338	3,942,000	12,350	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0451	1.0338	150	-	DEMAND	1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	Non-RPP (Other)	1.0451	1.0338	150		DEMAND	1
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0451	1.0338	657	1	DEMAND	1
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0451	1.0338	23,500	660	DEMAND	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0451	1.0338	233		N/A	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0451	1.0338	233		N/A	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0451	1.0338	800		N/A	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0451	1.0338	1,000		N/A	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0451	1.0338	500		N/A	
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	RPP	1.0451	1.0338	1,000		N/A	
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	RPP	1.0451	1.0338	5,000		N/A	
GENERAL SERVICE 50 TO 999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0451	1.0338	65,700	500	DEMAND	
GENERAL SERVICE 1,000 TO 4,999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0451	1.0338	821,250	2,500	DEMAND	
GENERAL SERVICE 1,000 TO 4,999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0451	1.0338	821,250	3,500	DEMAND	
Add additional scenarios if required								
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Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 2.70	8.9%	$ 2.00	5.6%	$ 0.50	1.1%	$ 0.49	0.4%
2	GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - RPP	kWh	$ 9.66	18.8%	$ 7.80	12.3%	$ 4.24	4.9%	$ 3.71	1.3%
3	GENERAL SERVICE 50 TO 999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (150.24)	-34.3%	$ (150,011.15)	-99.5%	$ (150,077.92)	-99.2%	$ (169,683.69)	-94.1%
4	GENERAL SERVICE 1,000 TO 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (1,916.13)	-24.5%	$ (3,018,777.21)	-99.6%	$ (3,019,678.46)	-99.4%	$ (3,413,432.13)	-96.2%
5	LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (2,810.86)	-8.3%	$ (2,810.07)	-8.1%	$ (46,168.45)	-45.2%	$ (57,908.58)	-8.5%
6	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ (7.33)	-36.0%	$ (6.86)	-30.5%	$ (7.12)	-29.4%	$ (8.06)	-16.8%
7	SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ (2,331.12)	-98.9%	$ (2,411.50)	-98.9%	$ (2,497.22)	-83.6%	$ (2,821.87)	-83.1%
8	STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (12.22)	-44.4%	$ (1,807.63)	-98.7%	$ (1,808.28)	-98.5%	$ (2,043.39)	-94.4%
9	EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (2,953.56)	-58.6%	$ (84,430.41)	-97.6%	$ (85,063.42)	-93.7%	$ (96,106.46)	-90.7%
10	RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 4.40	17.3%	$ 4.18	15.2%	$ 3.72	12.2%	$ 3.90	7.3%
11	RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 4.40	17.3%	$ 3.90	13.2%	$ 3.44	10.6%	$ 3.60	5.8%
12	RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 2.53	8.2%	$ 0.81	1.9%	$ (0.78)	-1.5%	$ (0.86)	-0.6%
13	RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.87	5.7%	$ 0.94	2.4%	$ (1.05)	-2.0%	$ (1.15)	-0.8%
14	RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 3.52	12.6%	$ 3.06	9.7%	$ 2.06	5.4%	$ 2.14	2.5%
15	GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - RPP	kWh	$ 7.16	19.5%	$ 6.23	14.4%	$ 4.45	8.1%	$ 4.30	2.8%
16	GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - RPP	kWh	$ 17.16	18.1%	$ 12.52	10.1%	$ 3.62	2.0%	$ 1.94	0.3%
17	GENERAL SERVICE 50 TO 999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (568.68)	-33.9%	$ -	0.0%	$ -	0.0%	$ -	0.0%
18	GENERAL SERVICE 1,000 TO 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%
19	GENERAL SERVICE 1,000 TO 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%
20										
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Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**RPP**	
Consumption	**750**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0451**	
Proposed/Approved Loss Factor	**1.0338**	

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 23.22	1	$ 23.22	$ 29.37	1	$ 29.37	$ 6.15	26.49%
Distribution Volumetric Rate	$ 0.0094	750	$ 7.05	$ 0.0053	750	$ 3.98	$ (3.08)	-43.62%
Fixed Rate Riders	$ -	1	$ -	$ (0.98)	1	$ (0.98)	$ (0.98)	
Volumetric Rate Riders	$ -	750	$ -	$ 0.0008	750	$ 0.60	$ 0.60	
Sub-Total A (excluding pass through)			$ 30.27			$ 32.97	**$ 2.70**	**8.90%**
Line Losses on Cost of Power	$ 0.0822	34	$ 2.78	$ 0.0822	25	$ 2.08	$ (0.70)	-25.06%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	0	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0021	750	$ 1.58	$ 0.0021	750	$ 1.58	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 35.41**			**$ 37.41**	**$ 2.00**	**5.64%**
RTSR - Network	$ 0.0063	784	$ 4.94	$ 0.0053	775	$ 4.11	$ (0.83)	-16.78%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0056	784	$ 4.39	$ 0.0048	775	$ 3.72	$ (0.67)	-15.21%
Sub-Total C - Delivery (including Sub-Total B)			**$ 44.74**			**$ 45.24**	**$ 0.50**	**1.12%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	784	$ 2.82	$ 0.0036	775	$ 2.79	$ (0.03)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	784	$ 0.24	$ 0.0003	775	$ 0.23	$ (0.00)	-1.08%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
TOU - Off Peak	$ 0.0650	488	$ 31.69	$ 0.0650	488	$ 31.69	$ -	0.00%
TOU - Mid Peak	$ 0.0950	128	$ 12.11	$ 0.0950	128	$ 12.11	$ -	0.00%
TOU - On Peak	$ 0.1320	135	$ 17.82	$ 0.1320	135	$ 17.82	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 109.67**			**$ 110.14**	**$ 0.47**	**0.43%**
HST	13%		$ 14.26	13%		$ 14.32	$ 0.06	0.43%
8% Rebate	8%		$ (8.77)	8%		$ (8.81)	$ (0.04)	
Total Bill on TOU			**$ 115.15**			**$ 115.64**	**$ 0.49**	**0.43%**

Customer Class:	**GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**RPP**	
Consumption	**2,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0451**	
Proposed/Approved Loss Factor	**1.0338**	

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 22.29**	1	$ 22.29	**$ 26.95**	1	$ 26.95	$ 4.66	20.91%
Distribution Volumetric Rate	**$ 0.0145**	2000	$ 29.00	**$ 0.0175**	2000	$ 35.00	$ 6.00	20.69%
Fixed Rate Riders	**$ -**	1	$ -	**$ -**	1	$ -	$ -	
Volumetric Rate Riders	**$ -**	2000	$ -	**-$ 0.0005**	2000	$ (1.00)	$ (1.00)	
Sub-Total A (excluding pass through)			$ 51.29			$ 60.95	**$ 9.66**	**18.83%**
Line Losses on Cost of Power	**$ 0.0822**	90	$ 7.41	**$ 0.0822**	68	$ 5.55	$ (1.86)	-25.06%
Total Deferral/Variance Account Rate Riders	**$ -**	2,000	$ -	**$ -**	2,000	$ -	$ -	
GA Rate Riders	**0**	2,000	$ -	**$ -**	2,000	$ -	$ -	
Low Voltage Service Charge	**$ 0.0020**	2,000	$ 4.00	**$ 0.0020**	2,000	$ 4.00	$ -	0.00%
Smart Meter Entity Charge (if applicable)	**$ 0.7900**	1	$ 0.79	**$ 0.7900**	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 63.49**			**$ 71.29**	**$ 7.80**	**12.29%**
RTSR - Network	**$ 0.0059**	2,090	$ 12.33	**$ 0.0050**	2,068	$ 10.34	$ (1.99)	-16.17%
RTSR - Connection and/or Line and Transformation Connection	**$ 0.0052**	2,090	$ 10.87	**$ 0.0045**	2,068	$ 9.30	$ (1.56)	-14.40%
Sub-Total C - Delivery (including Sub-Total B)			**$ 86.69**			**$ 90.94**	**$ 4.24**	**4.90%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	2,090	$ 7.52	**$ 0.0036**	2,068	$ 7.44	$ (0.08)	-1.08%
Rural and Remote Rate Protection (RRRP)	**$ 0.0003**	2,090	$ 0.63	**$ -**	2,068	$ -	$ (0.63)	-100.00%
Standard Supply Service Charge	**$ 0.2500**	1	$ 0.25	**$ 0.2500**	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	**$ 0.0070**	2,000	$ 14.00	**$ 0.0070**	2,000	$ 14.00	$ -	0.00%
TOU - Off Peak	**$ 0.0650**	1,300	$ 84.50	**$ 0.0650**	1,300	$ 84.50	$ -	0.00%
TOU - Mid Peak	**$ 0.0950**	340	$ 32.30	**$ 0.0950**	340	$ 32.30	$ -	0.00%
TOU - On Peak	**$ 0.1320**	360	$ 47.52	**$ 0.1320**	360	$ 47.52	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 273.41**			**$ 276.95**	**$ 3.54**	**1.29%**
HST	13%		$ 35.54	13%		$ 36.00	$ 0.46	1.29%
8% Rebate	8%		$ (21.87)	8%		$ (22.16)	$ (0.28)	
Total Bill on TOU			**$ 287.08**			**$ 290.80**	**$ 3.71**	**1.29%**

Customer Class:	**GENERAL SERVICE 50 TO 999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**65,700** kWh
Demand	**100** kW
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 127.91	1	$ 127.91	$ 82.28	1	$ 82.28	$ (45.63)	-35.67%
Distribution Volumetric Rate	$ 3.1024	100	$ 310.24	$ 2.0674	100	$ 206.74	$ (103.50)	-33.36%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	100	$ -	-$ 0.0111	100	$ (1.11)	$ (1.11)	
Sub-Total A (excluding pass through)			$ 438.15			$ 287.91	**$ (150.24)**	**-34.29%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	100	$ -	$ -	100	$ -	$ -	
GA Rate Riders	2.2875	65,700	$ 150,288.75	$ 0.0065	65,700	$ 427.05	$ (149,861.70)	-99.72%
Low Voltage Service Charge	$ 0.7099	100	$ 70.99	$ 0.7099	100	$ 70.99	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 150,797.89**			**$ 786.74**	**$ (150,011.15)**	**-99.48%**
RTSR - Network	$ 2.6482	100	$ 264.82	$ 2.2471	100	$ 224.71	$ (40.11)	-15.15%
RTSR - Connection and/or Line and Transformation Connection	$ 1.8703	100	$ 187.03	$ 1.6037	100	$ 160.37	$ (26.66)	-14.25%
Sub-Total C - Delivery (including Sub-Total B)			**$ 151,249.74**			**$ 1,171.82**	**$ (150,077.92)**	**-99.23%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	68,663	$ 247.19	$ 0.0036	67,921	$ 244.51	$ (2.67)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	68,663	$ 20.60	$ 0.0003	67,921	$ 20.38	$ (0.22)	-1.08%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	65,700	$ 459.90	$ 0.0070	65,700	$ 459.90	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	68,663	$ 7,559.80	$ 0.1101	67,921	$ 7,478.06	$ (81.74)	-1.08%
Total Bill on Average IESO Wholesale Market Price			**$ 159,537.23**			**$ 9,374.68**	**$ (150,162.55)**	**-94.12%**
HST	13%		$ 20,739.84	13%		$ 1,218.71	$ (19,521.13)	-94.12%
Total Bill on Average IESO Wholesale Market Price			**$ 180,277.07**			**$ 10,593.38**	**$ (169,683.69)**	**-94.12%**

Customer Class:	**GENERAL SERVICE 1,000 TO 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**821,250** kWh
Demand	**1,250** kW
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2,537.23	1	$ 2,537.23	$ 2,537.23	1	$ 2,537.23	$ -	0.00%
Distribution Volumetric Rate	$ 4.2161	1250	$ 5,270.13	$ 2.5270	1250	$ 3,158.75	$ (2,111.38)	-40.06%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	1250	$ -	$ 0.1562	1250	$ 195.25	$ 195.25	
Sub-Total A (excluding pass through)			$ 7,807.36			$ 5,891.23	**$ (1,916.13)**	**-24.54%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	1,250	$ -	$ -	1,250	$ -	$ -	
GA Rate Riders	3.68	821,250	$ 3,022,200.00	$ 0.0065	821,250	$ 5,338.13	$ (3,016,861.88)	-99.82%
Low Voltage Service Charge	$ 0.7635	1,250	$ 954.38	$ 0.7635	1,250	$ 954.38	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3,030,961.73**			**$ 12,184.52**	**$ (3,018,777.21)**	**-99.60%**
RTSR - Network	$ 2.8748	1,250	$ 3,593.50	$ 2.4394	1,250	$ 3,049.25	$ (544.25)	-15.15%
RTSR - Connection and/or Line and Transformation Connection	$ 2.0036	1,250	$ 2,504.50	$ 1.7180	1,250	$ 2,147.50	$ (357.00)	-14.25%
Sub-Total C - Delivery (including Sub-Total B)			**$ 3,037,059.73**			**$ 17,381.27**	**$ (3,019,678.46)**	**-99.43%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	858,288	$ 3,089.84	$ 0.0036	849,008	$ 3,056.43	$ (33.41)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	858,288	$ 257.49	$ 0.0003	849,008	$ 254.70	$ (2.78)	-1.08%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	821,250	$ 5,748.75	$ 0.0070	821,250	$ 5,748.75	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	858,288	$ 94,497.55	$ 0.1101	849,008	$ 93,475.81	$ (1,021.74)	-1.08%
Total Bill on Average IESO Wholesale Market Price			**$ 3,140,653.35**			**$ 119,916.96**	**$ (3,020,736.39)**	**-96.18%**
HST	13%		$ 408,284.94	13%		$ 15,589.20	$ (392,695.73)	-96.18%
Total Bill on Average IESO Wholesale Market Price			**$ 3,548,938.29**			**$ 135,506.17**	**$ (3,413,432.13)**	**-96.18%**

Customer Class:	**LARGE USE SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**3,942,000 kWh**
Demand	**12,350 kW**
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 10,362.66	1	$ 10,362.66	$ 10,362.66	1	$ 10,362.66	$ -	0.00%
Distribution Volumetric Rate	$ 1.9046	12350	$ 23,521.81	$ 2.5716	12350	$ 31,759.26	$ 8,237.45	35.02%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	12350	$ -	-$ 0.8946	12350	$ (11,048.31)	$ (11,048.31)	
Sub-Total A (excluding pass through)			$ 33,884.47			$ 31,073.61	**$ (2,810.86)**	**-8.30%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	12,350	$ -	$ -	12,350	$ -	$ -	
GA Rate Riders	0	3,942,000	$ -	$ -	3,942,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0733	12,350	$ 905.26	$ 0.0733	12,350	$ 905.26	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 34,789.73**			**$ 31,979.66**	**$ (2,810.07)**	**-8.08%**
RTSR - Network	$ 3.1869	12,350	$ 39,358.22	$ -	12,350	$ -	$ (39,358.22)	-100.00%
RTSR - Connection and/or Line and Transformation Connection	$ 2.2727	12,350	$ 28,067.85	$ 1.9488	12,350	$ 24,067.68	$ (4,000.17)	-14.25%
Sub-Total C - Delivery (including Sub-Total B)			**$ 102,215.79**			**$ 56,047.34**	**$ (46,168.45)**	**-45.17%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	4,119,784	$ 14,831.22	$ 0.0036	4,075,240	$ 14,670.86	$ (160.36)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	4,119,784	$ 1,235.94	$ 0.0003	4,075,240	$ 1,222.57	$ (13.36)	-1.08%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	3,942,000	$ 27,594.00	$ 0.0070	3,942,000	$ 27,594.00	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	4,119,784	$ 453,588.24	$ 0.1101	4,075,240	$ 448,683.88	$ (4,904.36)	-1.08%
Total Bill on Average IESO Wholesale Market Price			**$ 599,465.18**			**$ 548,218.65**	**$ (51,246.53)**	**-8.55%**
HST	13%		$ 77,930.47	13%		$ 71,268.42	$ (6,662.05)	-8.55%
Total Bill on Average IESO Wholesale Market Price			**$ 677,395.66**			**$ 619,487.07**	**$ (57,908.58)**	**-8.55%**

Customer Class:	**UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**150 kWh**
Demand	**- kW**
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 3.20**	1	$ 3.20	**$ 2.10**	1	$ 2.10	$ (1.10)	-34.38%
Distribution Volumetric Rate	**$ 0.1142**	150	$ 17.13	**$ 0.0749**	150	$ 11.24	$ (5.90)	-34.41%
Fixed Rate Riders	**$ -**	1	$ -	**$ -**	1	$ -	$ -	
Volumetric Rate Riders	**$ -**	150	$ -	**-$ 0.0022**	150	$ (0.33)	$ (0.33)	
Sub-Total A (excluding pass through)			$ 20.33			$ 13.01	**$ (7.33)**	**-36.03%**
Line Losses on Cost of Power	**$ 0.1101**	7	$ 0.74	**$ 0.1101**	5	$ 0.56	$ (0.19)	-25.06%
Total Deferral/Variance Account Rate Riders	**$ -**	150	$ -	**$ -**	150	$ -	$ -	
GA Rate Riders	**0.0074**	150	$ 1.11	**$ 0.0065**	150	$ 0.98	$ (0.14)	-12.16%
Low Voltage Service Charge	**$ 0.0020**	150	$ 0.30	**$ 0.0020**	150	$ 0.30	$ -	0.00%
Smart Meter Entity Charge (if applicable)	**$ -**	1	$ -	**$ 0.7900**	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 22.48**			**$ 15.63**	**$ (6.86)**	**-30.49%**
RTSR - Network	**$ 0.0059**	157	$ 0.92	**$ 0.0050**	155	$ 0.78	$ (0.15)	-16.17%
RTSR - Connection and/or Line and Transformation Connection	**$ 0.0052**	157	$ 0.82	**$ 0.0045**	155	$ 0.70	$ (0.12)	-14.40%
Sub-Total C - Delivery (including Sub-Total B)			**$ 24.22**			**$ 17.10**	**$ (7.12)**	**-29.41%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	157	$ 0.56	**$ 0.0036**	155	$ 0.56	$ (0.01)	-1.08%
Rural and Remote Rate Protection (RRRP)	**$ 0.0003**	157	$ 0.05	**$ 0.0003**	155	$ 0.05	$ (0.00)	-1.08%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	**$ 0.0070**	150	$ 1.05	**$ 0.0070**	150	$ 1.05	$ -	0.00%
Average IESO Wholesale Market Price	**$ 0.1101**	150	$ 16.52	**$ 0.1101**	150	$ 16.52	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 42.40**			**$ 35.27**	**$ (7.13)**	**-16.82%**
HST	13%		$ 5.51	13%		$ 4.59	$ (0.93)	-16.82%
Total Bill on Average IESO Wholesale Market Price			**$ 47.91**			**$ 39.86**	**$ (8.06)**	**-16.82%**

Customer Class:	**SENTINEL LIGHTING SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**150** kWh
Demand	**-** kW
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 5.59	1	$ 5.59	$ 12.31	1	$ 12.31	$ 6.72	120.21%
Distribution Volumetric Rate	$ 15.6727	150	$ 2,350.91	$ 0.0893	150	$ 13.40	$ (2,337.51)	-99.43%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	150	$ -	-$ 0.0022	150	$ (0.33)	$ (0.33)	
Sub-Total A (excluding pass through)			$ 2,356.50			$ 25.38	**$ (2,331.12)**	**-98.92%**
Line Losses on Cost of Power	$ 0.1101	7	$ 0.74	$ 0.1101	5	$ 0.56	$ (0.19)	-25.06%
Total Deferral/Variance Account Rate Riders	$ -	150	$ -	$ -	150	$ -	$ -	
GA Rate Riders	0	150	$ -	$ 0.0065	150	$ 0.98	$ 0.98	
Low Voltage Service Charge	$ 0.5482	150	$ 82.23	$ 0.0018	150	$ 0.27	$ (81.96)	-99.67%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 2,439.47**			**$ 27.97**	**$ (2,411.50)**	**-98.85%**
RTSR - Network	$ 2.0441	157	$ 320.44	$ 1.7345	155	$ 268.97	$ (51.47)	-16.06%
RTSR - Connection and/or Line and Transformation Connection	$ 1.4388	157	$ 225.55	$ 1.2337	155	$ 191.31	$ (34.24)	-15.18%
Sub-Total C - Delivery (including Sub-Total B)			**$ 2,985.47**			**$ 488.25**	**$ (2,497.22)**	**-83.65%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	157	$ 0.56	$ 0.0036	155	$ 0.56	$ (0.01)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	157	$ 0.05	$ 0.0003	155	$ 0.05	$ (0.00)	-1.08%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	150	$ 1.05	$ 0.0070	150	$ 1.05	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	150	$ 16.52	$ 0.1101	150	$ 16.52	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 3,003.64**			**$ 506.42**	**$ (2,497.23)**	**-83.14%**
HST	13%		$ 390.47	13%		$ 65.83	$ (324.64)	-83.14%
Total Bill on Average IESO Wholesale Market Price			**$ 3,394.12**			**$ 572.25**	**$ (2,821.87)**	**-83.14%**

Customer Class:	**STREET LIGHTING SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**657 kWh**
Demand	**1 kW**
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 4.04	1	$ 4.04	$ 2.25	1	$ 2.25	$ (1.79)	-44.31%
Distribution Volumetric Rate	$ 23.5048	1	$ 23.50	$ 13.1162	1	$ 13.12	$ (10.39)	-44.20%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	1	$ -	-$ 0.0424	1	$ (0.04)	$ (0.04)	
Sub-Total A (excluding pass through)			$ 27.54			$ 15.32	**$ (12.22)**	**-44.37%**
Line Losses on Cost of Power	$ 0.1101	30	$ 3.26	$ 0.1101	22	$ 2.44	$ (0.82)	-25.06%
Total Deferral/Variance Account Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
GA Rate Riders	2.7392	657	$ 1,799.65	$ 0.0065	657	$ 4.27	$ (1,795.38)	-99.76%
Low Voltage Service Charge	$ 0.5482	1	$ 0.55	$ 0.5482	1	$ 0.55	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,831.01**			**$ 23.38**	**$ (1,807.63)**	**-98.72%**
RTSR - Network	$ 2.0441	1	$ 2.04	$ 1.7345	1	$ 1.73	$ (0.31)	-15.15%
RTSR - Connection and/or Line and Transformation Connection	$ 2.3780	1	$ 2.38	$ 2.0391	1	$ 2.04	$ (0.34)	-14.25%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,835.43**			**$ 27.15**	**$ (1,808.28)**	**-98.52%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	687	$ 2.47	$ 0.0036	679	$ 2.45	$ (0.03)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	687	$ 0.21	$ 0.0003	679	$ 0.20	$ (0.00)	-1.08%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	657	$ 4.60	$ 0.0070	657	$ 4.60	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	657	$ 72.34	$ 0.1101	657	$ 72.34	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 1,915.04**			**$ 106.73**	**$ (1,808.31)**	**-94.43%**
HST	13%		$ 248.96	13%		$ 13.88	$ (235.08)	-94.43%
Total Bill on Average IESO Wholesale Market Price			**$ 2,164.00**			**$ 120.61**	**$ (2,043.39)**	**-94.43%**

Customer Class:	**EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**23,500** kWh
Demand	**660** kW
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2,361.50	1	$ 2,361.50	$ 978.34	1	$ 978.34	$ (1,383.16)	-58.57%
Distribution Volumetric Rate	$ 4.0623	660	$ 2,681.12	$ 1.6829	660	$ 1,110.71	$ (1,570.40)	-58.57%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	660	$ -	$ -	660	$ -	$ -	
Sub-Total A (excluding pass through)			$ 5,042.62			$ 2,089.05	**$ (2,953.56)**	**-58.57%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	660	$ -	$ -	660	$ -	$ -	
GA Rate Riders	3.4671	23,500	$ 81,476.85	$ -	23,500	$ -	$ (81,476.85)	-100.00%
Low Voltage Service Charge	$ -	660	$ -		660	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 86,519.47**			**$ 2,089.05**	**$ (84,430.41)**	**-97.59%**
RTSR - Network	$ 3.8460	660	$ 2,538.36	$ 3.2635	660	$ 2,153.91	$ (384.45)	-15.15%
RTSR - Connection and/or Line and Transformation Connection	$ 2.6423	660	$ 1,743.92	$ 2.2657	660	$ 1,495.36	$ (248.56)	-14.25%
Sub-Total C - Delivery (including Sub-Total B)			**$ 90,801.75**			**$ 5,738.33**	**$ (85,063.42)**	**-93.68%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	24,560	$ 88.42	$ 0.0036	24,294	$ 87.46	$ (0.96)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	24,560	$ 7.37	$ 0.0021	24,294	$ 51.02	$ 43.65	592.43%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	23,500	$ 164.50	$ 0.0070	23,500	$ 164.50	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	24,560	$ 2,704.04	$ 0.1101	24,294	$ 2,674.80	$ (29.24)	-1.08%
Total Bill on Average IESO Wholesale Market Price			**$ 93,766.07**			**$ 8,716.11**	**$ (85,049.96)**	**-90.70%**
HST	13%		$ 12,189.59	13%		$ 1,133.09	$ (11,056.50)	-90.70%
Total Bill on Average IESO Wholesale Market Price			**$ 105,955.66**			**$ 9,849.20**	**$ (96,106.46)**	**-90.70%**

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**233 kWh**
Demand	**- kW**
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 23.22	1	$ 23.22	$ 29.37	1	$ 29.37	$ 6.15	26.49%
Distribution Volumetric Rate	$ 0.0094	233	$ 2.19	$ 0.0053	233	$ 1.23	$ (0.96)	-43.62%
Fixed Rate Riders	$ -	1	$ -	$ (0.98)	1	$ (0.98)	$ (0.98)	
Volumetric Rate Riders	$ -	233	$ -	$ 0.0008	233	$ 0.19	$ 0.19	
Sub-Total A (excluding pass through)			$ 25.41			$ 29.81	**$ 4.40**	**17.32%**
Line Losses on Cost of Power	$ 0.0822	11	$ 0.86	$ 0.0822	8	$ 0.65	$ (0.22)	-25.06%
Total Deferral/Variance Account Rate Riders	$ -	233	$ -	$ -	233	$ -	$ -	
GA Rate Riders	0	233	$ -	$ -	233	$ -	$ -	
Low Voltage Service Charge	$ 0.0021	233	$ 0.49	$ 0.0021	233	$ 0.49	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 27.55**			**$ 31.74**	**$ 4.18**	**15.19%**
RTSR - Network	$ 0.0063	244	$ 1.53	$ 0.0053	241	$ 1.28	$ (0.26)	-16.78%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0056	244	$ 1.36	$ 0.0048	241	$ 1.16	$ (0.21)	-15.21%
Sub-Total C - Delivery (including Sub-Total B)			**$ 30.45**			**$ 34.17**	**$ 3.72**	**12.22%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	244	$ 0.88	$ 0.0036	241	$ 0.87	$ (0.01)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	244	$ 0.07	$ 0.0003	241	$ 0.07	$ (0.00)	-1.08%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
TOU - Off Peak	$ 0.0650	151	$ 9.84	$ 0.0650	151	$ 9.84	$ -	0.00%
TOU - Mid Peak	$ 0.0950	40	$ 3.76	$ 0.0950	40	$ 3.76	$ -	0.00%
TOU - On Peak	$ 0.1320	42	$ 5.54	$ 0.1320	42	$ 5.54	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 50.79**			**$ 54.50**	**$ 3.71**	**7.30%**
HST	13%		$ 6.60	13%		$ 7.09	$ 0.48	7.30%
8% Rebate	8%		$ (4.06)	8%		$ (4.36)	$ (0.30)	
Total Bill on TOU			**$ 53.33**			**$ 57.23**	**$ 3.90**	**7.30%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	233 kWh
Demand	- kW
Current Loss Factor	1.0451
Proposed/Approved Loss Factor	1.0338

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 23.22	1	$ 23.22	$ 29.37	1	$ 29.37	$ 6.15	26.49%
Distribution Volumetric Rate	$ 0.0094	233	$ 2.19	$ 0.0053	233	$ 1.23	$ (0.96)	-43.62%
Fixed Rate Riders	$ -	1	$ -	$ (0.98)	1	$ (0.98)	$ (0.98)	
Volumetric Rate Riders	$ -	233	$ -	$ 0.0008	233	$ 0.19	$ 0.19	
Sub-Total A (excluding pass through)			$ 25.41			$ 29.81	**$ 4.40**	**17.32%**
Line Losses on Cost of Power	$ 0.1101	11	$ 1.16	$ 0.1101	8	$ 0.87	$ (0.29)	-25.06%
Total Deferral/Variance Account Rate Riders	$ -	233	$ -	$ -	233	$ -	$ -	
GA Rate Riders	0.0074	233	$ 1.72	$ 0.0065	233	$ 1.51	$ (0.21)	-12.16%
Low Voltage Service Charge	$ 0.0021	233	$ 0.49	$ 0.0021	233	$ 0.49	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 29.57**			**$ 33.47**	**$ 3.90**	**13.19%**
RTSR - Network	$ 0.0063	244	$ 1.53	$ 0.0053	241	$ 1.28	$ (0.26)	-16.78%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0056	244	$ 1.36	$ 0.0048	241	$ 1.16	$ (0.21)	-15.21%
Sub-Total C - Delivery (including Sub-Total B)			**$ 32.47**			**$ 35.91**	**$ 3.44**	**10.59%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	244	$ 0.88	$ 0.0036	241	$ 0.87	$ (0.01)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	244	$ 0.07	$ 0.0003	241	$ 0.07	$ (0.00)	-1.08%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)								
Non-RPP Retailer Avg. Price	$ 0.1101	233	$ 25.65	$ 0.1101	233	$ 25.65	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 59.07**			**$ 62.50**	**$ 3.43**	**5.80%**
HST	13%		$ 7.68	13%		$ 8.12	$ 0.45	5.80%
8% Rebate	8%		$ (4.73)	8%		$ (5.00)		
Total Bill on Non-RPP Avg. Price			**$ 62.02**			**$ 65.62**	**$ 3.60**	**5.80%**

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**800** **kWh**
Demand	**-** **kW**
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 23.22**	1	$ 23.22	**$ 29.37**	1	$ 29.37	$ 6.15	26.49%
Distribution Volumetric Rate	**$ 0.0094**	800	$ 7.52	**$ 0.0053**	800	$ 4.24	$ (3.28)	-43.62%
Fixed Rate Riders	**$ -**	1	$ -	**$ (0.98)**	1	$ (0.98)	$ (0.98)	
Volumetric Rate Riders	**$ -**	800	$ -	**$ 0.0008**	800	$ 0.64	$ 0.64	
Sub-Total A (excluding pass through)			$ 30.74			$ 33.27	**$ 2.53**	**8.23%**
Line Losses on Cost of Power	**$ 0.1101**	36	$ 3.97	**$ 0.1101**	27	$ 2.98	$ (1.00)	-25.06%
Total Deferral/Variance Account Rate Riders	**$ -**	800	$ -	**$ -**	800	$ -	$ -	
GA Rate Riders	**0.0074**	800	$ 5.92	**$ 0.0065**	800	$ 5.20	$ (0.72)	-12.16%
Low Voltage Service Charge	**$ 0.0021**	800	$ 1.68	**$ 0.0021**	800	$ 1.68	$ -	0.00%
Smart Meter Entity Charge (if applicable)	**$ 0.7900**	1	$ 0.79	**$ 0.7900**	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 43.10**			**$ 43.92**	**$ 0.81**	**1.89%**
RTSR - Network	**$ 0.0063**	836	$ 5.27	**$ 0.0053**	827	$ 4.38	$ (0.88)	-16.78%
RTSR - Connection and/or Line and Transformation Connection	**$ 0.0056**	836	$ 4.68	**$ 0.0048**	827	$ 3.97	$ (0.71)	-15.21%
Sub-Total C - Delivery (including Sub-Total B)			**$ 53.05**			**$ 52.27**	**$ (0.78)**	**-1.47%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	836	$ 3.01	**$ 0.0036**	827	$ 2.98	$ (0.03)	-1.08%
Rural and Remote Rate Protection (RRRP)	**$ 0.0003**	836	$ 0.25	**$ 0.0003**	827	$ 0.25	$ (0.00)	-1.08%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)								
Non-RPP Retailer Avg. Price	**$ 0.1101**	800	$ 88.08	**$ 0.1101**	800	$ 88.08	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 144.39**			**$ 143.58**	**$ (0.82)**	**-0.57%**
HST	13%		$ 18.77	13%		$ 18.66	$ (0.11)	-0.57%
8% Rebate	8%		$ (11.55)	8%		$ (11.49)		
Total Bill on Non-RPP Avg. Price			**$ 151.61**			**$ 150.75**	**$ (0.86)**	**-0.57%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	**1,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0451**	
Proposed/Approved Loss Factor	**1.0338**	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 23.22	1	$ 23.22	$ 29.37	1	$ 29.37	$ 6.15	26.49%
Distribution Volumetric Rate	$ 0.0094	1000	$ 9.40	$ 0.0053	1000	$ 5.30	$ (4.10)	-43.62%
Fixed Rate Riders	$ -	1	$ -	$ (0.98)	1	$ (0.98)	$ (0.98)	
Volumetric Rate Riders	$ -	1000	$ -	$ 0.0008	1000	$ 0.80	$ 0.80	
Sub-Total A (excluding pass through)			$ 32.62			$ 34.49	**$ 1.87**	**5.73%**
Line Losses on Cost of Power	$ 0.0822	45	$ 3.71	$ 0.0822	34	$ 2.78	$ (0.93)	-25.06%
Total Deferral/Variance Account Rate Riders	$ -	1,000	$ -	$ -	1,000	$ -	$ -	
GA Rate Riders	0	1,000	$ -	$ -	1,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0021	1,000	$ 2.10	$ 0.0021	1,000	$ 2.10	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 39.22**			**$ 40.16**	**$ 0.94**	**2.40%**
RTSR - Network	$ 0.0063	1,045	$ 6.58	$ 0.0053	1,034	$ 5.48	$ (1.10)	-16.78%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0056	1,045	$ 5.85	$ 0.0048	1,034	$ 4.96	$ (0.89)	-15.21%
Sub-Total C - Delivery (including Sub-Total B)			**$ 51.65**			**$ 50.60**	**$ (1.05)**	**-2.04%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	1,045	$ 3.76	$ 0.0036	1,034	$ 3.72	$ (0.04)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	1,045	$ 0.31	$ 0.0003	1,034	$ 0.31	$ (0.00)	-1.08%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
TOU - Off Peak	$ 0.0650	650	$ 42.25	$ 0.0650	650	$ 42.25	$ -	0.00%
TOU - Mid Peak	$ 0.0950	170	$ 16.15	$ 0.0950	170	$ 16.15	$ -	0.00%
TOU - On Peak	$ 0.1320	180	$ 23.76	$ 0.1320	180	$ 23.76	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 138.14**			**$ 137.04**	**$ (1.10)**	**-0.79%**
HST	13%		$ 17.96	13%		$ 17.82	$ (0.14)	-0.79%
8% Rebate	8%		$ (11.05)	8%		$ (10.96)	$ 0.09	
Total Bill on TOU			**$ 145.04**			**$ 143.89**	**$ (1.15)**	**-0.79%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	**500** kWh
Demand	**-** kW
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 23.22	1	$ 23.22	$ 29.37	1	$ 29.37	$ 6.15	26.49%
Distribution Volumetric Rate	$ 0.0094	500	$ 4.70	$ 0.0053	500	$ 2.65	$ (2.05)	-43.62%
Fixed Rate Riders	$ -	1	$ -	$ (0.98)	1	$ (0.98)	$ (0.98)	
Volumetric Rate Riders	$ -	500	$ -	$ 0.0008	500	$ 0.40	$ 0.40	
Sub-Total A (excluding pass through)			$ 27.92			$ 31.44	**$ 3.52**	**12.61%**
Line Losses on Cost of Power	$ 0.0822	23	$ 1.85	$ 0.0822	17	$ 1.39	$ (0.46)	-25.06%
Total Deferral/Variance Account Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
GA Rate Riders	0	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge	$ 0.0021	500	$ 1.05	$ 0.0021	500	$ 1.05	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 31.61**			**$ 34.67**	**$ 3.06**	**9.67%**
RTSR - Network	$ 0.0063	523	$ 3.29	$ 0.0053	517	$ 2.74	$ (0.55)	-16.78%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0056	523	$ 2.93	$ 0.0048	517	$ 2.48	$ (0.45)	-15.21%
Sub-Total C - Delivery (including Sub-Total B)			**$ 37.83**			**$ 39.89**	**$ 2.06**	**5.44%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	523	$ 1.88	$ 0.0036	517	$ 1.86	$ (0.02)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	523	$ 0.16	$ 0.0003	517	$ 0.16	$ (0.00)	-1.08%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
TOU - Off Peak	$ 0.0650	325	$ 21.13	$ 0.0650	325	$ 21.13	$ -	0.00%
TOU - Mid Peak	$ 0.0950	85	$ 8.08	$ 0.0950	85	$ 8.08	$ -	0.00%
TOU - On Peak	$ 0.1320	90	$ 11.88	$ 0.1320	90	$ 11.88	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 81.20**			**$ 83.24**	**$ 2.04**	**2.51%**
HST	13%		$ 10.56	13%		$ 10.82	$ 0.26	2.51%
8% Rebate	8%		$ (6.50)	8%		$ (6.66)	$ (0.16)	
Total Bill on TOU			**$ 85.26**			**$ 87.40**	**$ 2.14**	**2.51%**

Customer Class:	GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	1,000 kWh
Demand	- kW
Current Loss Factor	1.0451
Proposed/Approved Loss Factor	1.0338

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 22.29	1	$ 22.29	$ 26.95	1	$ 26.95	$ 4.66	20.91%
Distribution Volumetric Rate	$ 0.0145	1000	$ 14.50	$ 0.0175	1000	$ 17.50	$ 3.00	20.69%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	1000	$ -	-$ 0.0005	1000	$ (0.50)	$ (0.50)	
Sub-Total A (excluding pass through)			$ 36.79			$ 43.95	**$ 7.16**	**19.46%**
Line Losses on Cost of Power	$ 0.0822	45	$ 3.71	$ 0.0822	34	$ 2.78	$ (0.93)	-25.06%
Total Deferral/Variance Account Rate Riders	$ -	1,000	$ -	$ -	1,000	$ -	$ -	
GA Rate Riders	0	1,000	$ -	$ -	1,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0020	1,000	$ 2.00	$ 0.0020	1,000	$ 2.00	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 43.29**			**$ 49.52**	**$ 6.23**	**14.40%**
RTSR - Network	$ 0.0059	1,045	$ 6.17	$ 0.0050	1,034	$ 5.17	$ (1.00)	-16.17%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0052	1,045	$ 5.43	$ 0.0045	1,034	$ 4.65	$ (0.78)	-14.40%
Sub-Total C - Delivery (including Sub-Total B)			**$ 54.89**			**$ 59.34**	**$ 4.45**	**8.11%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	1,045	$ 3.76	$ 0.0036	1,034	$ 3.72	$ (0.04)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	1,045	$ 0.31	$ -	1,034	$ -	$ (0.31)	-100.00%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ 0.0070	1,000	$ 7.00	$ 0.0070	1,000	$ 7.00	$ -	0.00%
TOU - Off Peak	$ 0.0650	650	$ 42.25	$ 0.0650	650	$ 42.25	$ -	0.00%
TOU - Mid Peak	$ 0.0950	170	$ 16.15	$ 0.0950	170	$ 16.15	$ -	0.00%
TOU - On Peak	$ 0.1320	180	$ 23.76	$ 0.1320	180	$ 23.76	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 148.37**			**$ 152.47**	**$ 4.10**	**2.76%**
HST	13%		$ 19.29	13%		$ 19.82	$ 0.53	2.76%
8% Rebate	8%		$ (11.87)	8%		$ (12.20)	$ (0.33)	
Total Bill on TOU			**$ 155.79**			**$ 160.09**	**$ 4.30**	**2.76%**

Customer Class:	**GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**5,000** **kWh**
Demand	**-** **kW**
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 22.29**	1	$ 22.29	**$ 26.95**	1	$ 26.95	$ 4.66	20.91%
Distribution Volumetric Rate	**$ 0.0145**	5000	$ 72.50	**$ 0.0175**	5000	$ 87.50	$ 15.00	20.69%
Fixed Rate Riders	**$ -**	1	$ -	**$ -**	1	$ -	$ -	
Volumetric Rate Riders	**$ -**	5000	$ -	**-$ 0.0005**	5000	$ (2.50)	$ (2.50)	
Sub-Total A (excluding pass through)			$ 94.79			$ 111.95	**$ 17.16**	**18.10%**
Line Losses on Cost of Power	**$ 0.0822**	226	$ 18.53	**$ 0.0822**	169	$ 13.89	$ (4.64)	-25.06%
Total Deferral/Variance Account Rate Riders	**$ -**	5,000	$ -	**$ -**	5,000	$ -	$ -	
GA Rate Riders	**0**	5,000	$ -	**$ -**	5,000	$ -	$ -	
Low Voltage Service Charge	**$ 0.0020**	5,000	$ 10.00	**$ 0.0020**	5,000	$ 10.00	$ -	0.00%
Smart Meter Entity Charge (if applicable)	**$ 0.7900**	1	$ 0.79	**$ 0.7900**	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 124.11**			**$ 136.63**	**$ 12.52**	**10.09%**
RTSR - Network	**$ 0.0059**	5,226	$ 30.83	**$ 0.0050**	5,169	$ 25.85	$ (4.99)	-16.17%
RTSR - Connection and/or Line and Transformation Connection	**$ 0.0052**	5,226	$ 27.17	**$ 0.0045**	5,169	$ 23.26	$ (3.91)	-14.40%
Sub-Total C - Delivery (including Sub-Total B)			**$ 182.11**			**$ 185.73**	**$ 3.62**	**1.99%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	5,226	$ 18.81	**$ 0.0036**	5,169	$ 18.61	$ (0.20)	-1.08%
Rural and Remote Rate Protection (RRRP)	**$ 0.0003**	5,226	$ 1.57	**$ -**	5,169	$ -	$ (1.57)	-100.00%
Standard Supply Service Charge	**$ 0.2500**	1	$ 0.25	**$ 0.2500**	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	**$ 0.0070**	5,000	$ 35.00	**$ 0.0070**	5,000	$ 35.00	$ -	0.00%
TOU - Off Peak	**$ 0.0650**	3,250	$ 211.25	**$ 0.0650**	3,250	$ 211.25	$ -	0.00%
TOU - Mid Peak	**$ 0.0950**	850	$ 80.75	**$ 0.0950**	850	$ 80.75	$ -	0.00%
TOU - On Peak	**$ 0.1320**	900	$ 118.80	**$ 0.1320**	900	$ 118.80	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 648.54**			**$ 650.39**	**$ 1.85**	**0.29%**
HST	13%		$ 84.31	13%		$ 84.55	$ 0.24	0.29%
8% Rebate	8%		$ (51.88)	8%		$ (52.03)	$ (0.15)	0.29%
Total Bill on TOU			**$ 680.97**			**$ 682.91**	**$ 1.94**	**0.29%**

Customer Class:	GENERAL SERVICE 50 TO 999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	65,700 kWh
Demand	500 kW
Current Loss Factor	1.0451
Proposed/Approved Loss Factor	1.0338

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 127.91	1	$ 127.91	$ 82.28	1	$ 82.28	$ (45.63)	-35.67%
Distribution Volumetric Rate	$ 3.1024	500	$ 1,551.20	$ 2.0674	500	$ 1,033.70	$ (517.50)	-33.36%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	500	$ -	-$ 0.0111	500	$ (5.55)	$ (5.55)	
Sub-Total A (excluding pass through)			$ 1,679.11			$ 1,110.43	**$ (568.68)**	**-33.87%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
GA Rate Riders	2.2875	65,700	$ 150,288.75	$ 0.0065	65,700	$ 427.05	$ (149,861.70)	-99.72%
Low Voltage Service Charge	$ 0.7099	500	$ 354.95	$ 0.7099	500	$ 354.95	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 152,322.81**			**$ 1,893.22**	**$ (150,429.59)**	**-98.76%**
RTSR - Network	$ 2.6482	500	$ 1,324.10	$ 2.2471	500	$ 1,123.55	$ (200.55)	-15.15%
RTSR - Connection and/or Line and Transformation Connection	$ 1.8703	500	$ 935.15	$ 1.6037	500	$ 801.85	$ (133.30)	-14.25%
Sub-Total C - Delivery (including Sub-Total B)			**$ 154,582.06**			**$ 3,818.62**	**$ (150,763.44)**	**-97.53%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	68,663	$ 247.19	$ 0.0036	67,921	$ 244.51	$ (2.67)	-1.08%
Rural and Remote Rate Protection (RRRP)	$ 0.0003	68,663	$ 20.60	$ 0.0003	67,921	$ 20.38	$ (0.22)	-1.08%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	65,700	$ 459.90	$ 0.0070	65,700	$ 459.90	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	68,663	$ 7,559.80	$ 0.1101	67,921	$ 7,478.06	$ (81.74)	-1.08%
Total Bill on Average IESO Wholesale Market Price			**$ 162,869.55**			**$ 12,021.48**	**$ (150,848.07)**	**-92.62%**
HST	13%		$ 21,173.04	13%		$ 1,562.79	$ (19,610.25)	-92.62%
Total Bill on Average IESO Wholesale Market Price			**$ 184,042.59**			**$ 13,584.27**	**$ (170,458.32)**	**-92.62%**

Customer Class:	**GENERAL SERVICE 1,000 TO 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**821,250 kWh**
Demand	**2,500 kW**
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 2,537.23**	1	$ 2,537.23	$ 2,537.23	1	$ 2,537.23	$ -	0.00%
Distribution Volumetric Rate	**$ 4.2161**	2500	$ 10,540.25	$ 2.5270	2500	$ 6,317.50	$ (4,222.75)	-40.06%
Fixed Rate Riders	**$ -**	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	**$ -**	2500	$ -	$ 0.1562	2500	$ 390.50	$ 390.50	
Sub-Total A (excluding pass through)			$ 13,077.48			$ 9,245.23	**$ (3,832.25)**	**-29.30%**
Line Losses on Cost of Power	**$ -**	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	**$ -**	2,500	$ -	$ -	2,500	$ -	$ -	
GA Rate Riders	**3.68**	821,250	$ 3,022,200.00	$ 0.0065	821,250	$ 5,338.13	$ (3,016,861.88)	-99.82%
Low Voltage Service Charge	**$ 0.7635**	2,500	$ 1,908.75	$ 0.7635	2,500	$ 1,908.75	$ -	0.00%
Smart Meter Entity Charge (if applicable)	**$ -**	1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3,037,186.23**			**$ 16,492.90**	**$ (3,020,693.34)**	**-99.46%**
RTSR - Network	**$ 2.8748**	2,500	$ 7,187.00	$ 2.4394	2,500	$ 6,098.50	$ (1,088.50)	-15.15%
RTSR - Connection and/or Line and Transformation Connection	**$ 2.0036**	2,500	$ 5,009.00	$ 1.7180	2,500	$ 4,295.00	$ (714.00)	-14.25%
Sub-Total C - Delivery (including Sub-Total B)			**$ 3,049,382.23**			**$ 26,886.40**	**$ (3,022,495.84)**	**-99.12%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	858,288	$ 3,089.84	$ 0.0036	849,008	$ 3,056.43	$ (33.41)	-1.08%
Rural and Remote Rate Protection (RRRP)	**$ 0.0003**	858,288	$ 257.49	$ 0.0003	849,008	$ 254.70	$ (2.78)	-1.08%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	**$ 0.0070**	821,250	$ 5,748.75	$ 0.0070	821,250	$ 5,748.75	$ -	0.00%
Average IESO Wholesale Market Price	**$ 0.1101**	858,288	$ 94,497.55	$ 0.1101	849,008	$ 93,475.81	$ (1,021.74)	-1.08%
Total Bill on Average IESO Wholesale Market Price			**$ 3,152,975.85**			**$ 129,422.09**	**$ (3,023,553.77)**	**-95.90%**
HST	13%		$ 409,886.86	13%		$ 16,824.87	$ (393,061.99)	-95.90%
Total Bill on Average IESO Wholesale Market Price			**$ 3,562,862.72**			**$ 146,246.96**	**$ (3,416,615.76)**	**-95.90%**

Customer Class:	**GENERAL SERVICE 1,000 TO 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**821,250 kWh**
Demand	**3,500 kW**
Current Loss Factor	**1.0451**
Proposed/Approved Loss Factor	**1.0338**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 2,537.23**	1	$ 2,537.23	**$ 2,537.23**	1	$ 2,537.23	$ -	0.00%
Distribution Volumetric Rate	**$ 4.2161**	3500	$ 14,756.35	**$ 2.5270**	3500	$ 8,844.50	$ (5,911.85)	-40.06%
Fixed Rate Riders	**$ -**	1	$ -	**$ -**	1	$ -	$ -	
Volumetric Rate Riders	**$ -**	3500	$ -	**$ 0.1562**	3500	$ 546.70	$ 546.70	
Sub-Total A (excluding pass through)			$ 17,293.58			$ 11,928.43	**$ (5,365.15)**	**-31.02%**
Line Losses on Cost of Power	**$ -**	-	$ -	**$ -**	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	**$ -**	3,500	$ -	**$ -**	3,500	$ -	$ -	
GA Rate Riders	**3.68**	821,250	$ 3,022,200.00	**$ 0.0065**	821,250	$ 5,338.13	$ (3,016,861.88)	-99.82%
Low Voltage Service Charge	**$ 0.7635**	3,500	$ 2,672.25	**$ 0.7635**	3,500	$ 2,672.25	$ -	0.00%
Smart Meter Entity Charge (if applicable)	**$ -**	1	$ -	**$ 0.7900**	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3,042,165.83**			**$ 19,939.60**	**$ (3,022,226.24)**	**-99.34%**
RTSR - Network	**$ 2.8748**	3,500	$ 10,061.80	**$ 2.4394**	3,500	$ 8,537.90	$ (1,523.90)	-15.15%
RTSR - Connection and/or Line and Transformation Connection	**$ 2.0036**	3,500	$ 7,012.60	**$ 1.7180**	3,500	$ 6,013.00	$ (999.60)	-14.25%
Sub-Total C - Delivery (including Sub-Total B)			**$ 3,059,240.23**			**$ 34,490.50**	**$ (3,024,749.74)**	**-98.87%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	858,288	$ 3,089.84	**$ 0.0036**	849,008	$ 3,056.43	$ (33.41)	-1.08%
Rural and Remote Rate Protection (RRRP)	**$ 0.0003**	858,288	$ 257.49	**$ 0.0003**	849,008	$ 254.70	$ (2.78)	-1.08%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	**$ 0.0070**	821,250	$ 5,748.75	**$ 0.0070**	821,250	$ 5,748.75	$ -	0.00%
Average IESO Wholesale Market Price	**$ 0.1101**	858,288	$ 94,497.55	**$ 0.1101**	849,008	$ 93,475.81	$ (1,021.74)	-1.08%
Total Bill on Average IESO Wholesale Market Price			**$ 3,162,833.85**			**$ 137,026.19**	**$ (3,025,807.67)**	**-95.67%**
HST	13%		$ 411,168.40	13%		$ 17,813.40	$ (393,355.00)	-95.67%
Total Bill on Average IESO Wholesale Market Price			**$ 3,574,002.26**			**$ 154,839.59**	**$ (3,419,162.67)**	**-95.67%**